BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120009-EI

In the Matter of:

NUCLEAR COST RECOVERY CLAUSE.
______________________________/

VOLUME 6

Pages 911 through 1149

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, September 11, 2012

TIME: Commenced at 11:42 a.m.
Concluded at 2:21 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
45		916
46		916
47		916
48		916
49		916
50		916
51		1130
52		1130
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EXHIBITS

NUMBER:	ID.	ADMTD.
68		1130
69		1130
70		1130
71		1130
72		1130
73		1130
74		1130
75		1130
112		1130
113		1130
131	977	1130

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

CHAIRMAN BRISÉ: Okay. FPL, please call your next witness.

MS. CANO: Next on the list is Winnie Powers, who has been stipulated to and excused. So at this time FPL would move the prefiled testimony of Ms. Powers into the record. This includes her testimony filed March 1st, April 27th, errata filed June 11th, and her supplemental testimony filed September 7th, and we would move that as though read.

CHAIRMAN BRISÉ: All right. We will enter Ms. Winnie Powers' testimony into the record as though read --

MS. CANO: And --

CHAIRMAN BRISÉ: -- seeing no objections.

MS. CANO: Sorry. Thank you. And FPL also moves her prefiled exhibits WP-1 through WP-6, which are marked as Exhibits 45 through 50 on the composite exhibit list. And I would just note that these are as corrected by the errata that was just moved a moment ago with the testimony.

CHAIRMAN BRISÉ: Okay. We will move Exhibits 45 through 50 into the record, with the comment that the errata sheet that travels with these exhibits have been moved into the record already.

MS. CANO: Thank you.

(Exhibit 45, 46, 47, 48, 49, and 50 admitted into the record.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Power Plant) Costs Recovery Clause)	DOCKET NO. 120009-EI FILED: June 11, 2012

ERRATA SHEET

MARCH 1, 2012 TESTIMONY AND EXHIBITS OF WINNIE POWERS

MARCH 1, 2012 TESTIMONY OF WINNIE POWERS

PAGE #	LINE #	
Page 3	Line 22	Change "($15,767,471)" to "($15,102,473)"
Page 3	Line 23	Change "$119,802,583" to "$120,467,581"
Page 4	Line 4	Change "$15,767,471" to "$15,102,473"
Page 4	Line 18	Change "$15,767,471" to "$15,102,473"
Page 4	Line 21	Change "$119,802,583" to "$120,467,581"
Page 11	Line 9	Change "$394,941" to "$270,057"
Page 11	Line 9	Change "Overrecovery" to " Underrecovery"
Page 11	Line 10	Change "$7,299,217" to "$7,964,134"
Page 11	Line 12	Change "$7,014,783" to "$7,014,702"
Page 11	Line 13	Change "$394,941" to "$270,057"
Page 11	Line 13	Change "Overrecovery" to " Underrecovery"
Page 11	Line 13	Change "reduce" to "be included, in"
Page 11	Line 19	Change "$666,684,324" to "$667,493,187"
Page 11	Line 23	Change "$640,057,608" to "$640,855,812"
Page 12	Line 4	Change "$621,131,017" to "$621,935,221"
Page 12	Line 10	Change "$77,586,524" to "$78,251,442"
Page 12	Line 14	Change "$7,299,217" to "$7,964,134"
Page 14	Line 7	Change "$9,825,669" to "$9,825,749"
Page 14	Line 7	Change "$9,138,802" to "$9,138,883"
Page 14	Line 8	Change "($686,867)" to "($686,866)"
Page 14	Line 12	Change "$7,014,783" to "$7,014,702"
Page 14	Line 21	Change "$146,881,977" to "$146,949,175"
Page 15	Line 9	Change "$146,881,977" to "$146,949,175"

COM ____
APA 1
ECR 1
GCL 1
RAD 1
SRC ____
ADM ____
OPC ____
CLK 1-CtRep

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WINNIE POWERS

DOCKET NO. 120009-EI

MARCH 1, 2012

Q. Please state your name and business address.

A. My name is Winnie Powers. My business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as the New Nuclear Accounting Project Manager.

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

A. I am responsible for the accounting related to the new nuclear projects, which include Turkey Point 6 & 7 (TP 6 & 7 or New Nuclear) and the Extended Power Uprate Project at Turkey Point and St. Lucie Nuclear Plants (EPU or Uprate). I ensure that the costs expended and projected for these projects are accurately reflected in the Nuclear Cost Recovery filing requirements (NFR) schedules. In addition, I am responsible for ensuring that the Company's assets associated with these projects are appropriately recorded and reflected in FPL's financial statements.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1976 with a Bachelor of Science Degree in Business Administration, majoring in Accounting. After college, I was employed as an accountant by RCA Corporation in New York. In 1983, I was hired by Southeastern Public Service Company in Miami and attained the position of manager of corporate accounting. In 1985, I joined FPL and have held a variety of positions in the regulatory and accounting areas during my 27 years with the Company. I obtained my Masters of Accounting from Florida International University in 1994. I am a Certified Public Accountant (CPA) licensed in the State of Florida, and I am a member of the American Institute of CPAs.

Q. Are you sponsoring or co-sponsoring any Exhibits in this case?

A. Yes, I am sponsoring the following Exhibits for the TP 6 & 7 and Uprate Projects:

- Exhibit WP-1, 2011 Revenue Requirements, details the components of the 2011 TP 6 & 7 and Uprate revenue requirements reflected in the True-Up (T schedules) by project, by year and by category of costs being recovered (e.g. for Site Selection and Preconstruction costs, carrying costs on unrecovered balances and on the deferred tax asset/liability, and for Uprates, carrying costs on construction costs and on the deferred tax asset/liability, recoverable operation and maintenance (O&M) costs including interest, and base rate revenue requirements including interest for the year plant is placed into service).
- Exhibit WP-2, 2011 TP 6 & 7 Preconstruction Costs and Uprate Construction Costs, details the total company costs and jurisdictional costs by project and by cost category.

- Exhibit WP-3, 2011 Base Rate Revenue Requirements details the 2011 actual revenue requirements for the Uprate plant modifications placed into service during 2011, the true-up of the in-service date, true-up of the actual plant placed into service, and the rate of return. FPL Witness Jones describes the plant being placed into service.
- Exhibit WP–4, 2011 Incremental Labor Guidelines flowcharts the process used by the business unit accounting teams to determine incremental payroll costs chargeable to the projects for 2011.

Additionally, I sponsor or co-sponsor some of the NFRs included in exhibits sponsored by FPL Witnesses Scroggs and Jones as described below:

- Exhibit SDS-1, T Schedules, 2011 TP 6 & 7 Site Selection and Preconstruction costs, consists of the 2011 TP 6 & 7 Site Selection Schedules T-1, T-2 and T-3A and the 2011 TP 6 & 7 Preconstruction Schedules T-1 through T-7B. Page 2 of SDS-1 contains a table of contents which lists the T Schedules sponsored and co-sponsored by FPL Witness Scroggs and by me, respectively.
- Exhibit TOJ-1, T Schedules, 2011 EPU Construction Costs, consists of the 2011 Uprate Schedules T-1 through T-7B. Page 2 of TOJ-1 contains a table of contents which lists the T Schedules sponsored and co-sponsored by FPL Witness Jones and by me, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the true-up calculation of the 2011 revenue requirements of ($15,767,471). This is a result of the difference between $119,802,583 in actual 2011 revenue requirements that FPL is requesting the

Commission approve as prudent in this filing compared to the Actual/Estimated revenue requirements for 2011 of $135,570,054 (approved by the Commission in Docket No. 110009-EI, Order No. PSC 11-0547-FOF-EI). The overrecovery of $15,767,471 will reduce the Capacity Cost Recovery Clause (CCRC) charge to be paid by customers in 2013. The revenue requirements are summarized in my Exhibit WP-1 and shown in the NFR T Schedules for 2011 TP 6 & 7 Site Selection and Preconstruction costs and 2011 Uprate costs. I provide an overview of the components of the revenue requirements included in FPL's filing and demonstrate that the filing complies with the Florida Public Service Commission (FPSC or Commission) Rule No. 25-6.0423, Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery (NCR) Rule. I also explain how carrying costs are provided for under the Nuclear Cost Recovery Rule, describe the base rate revenue requirements included for recovery in the schedules, and discuss the Accounting controls FPL relies upon to ensure only appropriate costs are charged to the projects.

Q. Please summarize your testimony.

A. FPL is requesting the Commission approve as prudent its 2011 costs and the resulting overrecovery of revenue requirements of $15,767,471 which will reduce the CCRC charge to customers in 2013. As shown in my Exhibit WP-1, these revenue requirements are comprised of the difference between $119,802,583 actual costs versus $135,570,054 Actual/Estimated costs. My testimony includes the exhibits and NFRs needed to support the true-up of the 2011 actual costs.

My testimony also describes FPL's compliance with the NCR Rule and the robust and comprehensive corporate and overlapping business unit controls for incurring and validating costs and recording transactions associated with FPL's TP 6 & 7 and Uprate Projects. I describe these controls and outline the documentation, assessment and auditing process for these overlapping control activities. Throughout my testimony, I refer to exhibits and NFR schedules that provide an overview of the true-up of the 2011 revenue requirements FPL is requesting be included in the CCRC in 2013.

NUCLEAR COST RECOVERY RULE

Q. Please describe the Commission's Nuclear Cost Recovery Rule and the NFR schedules.

A. On March 20, 2007, in Order No. PSC-07-0240-FOF-EI, the FPSC adopted the Nuclear Cost Recovery Rule to implement Section 366.93, Florida Statutes (the Statute), which was enacted by the Florida Legislature in 2006.

The NFR schedules provide an overview of nuclear power plant projects and a roadmap to the detailed project costs. The NFR schedules consist of True-Up (T), Actual/Estimated (AE), Projected (P), and True-Up to Original (TOR) Schedules. The T Schedules filed each March provide the True-Up for the prior year.

The Nuclear Cost Recovery Rule applies to FPL's TP 6 & 7 and Uprate Projects. In compliance with the NCR Rule, FPL is recovering the costs and carrying costs for the TP 6 & 7 Project on an annual basis, as they are incurred for the licensing and permitting activites described by FPL Witness Scroggs. Since the Uprate Project is in the construction phase, FPL is recovering only the carrying charges on the construction balance together with recoverable O&M and the base rate revenue requirements for the year plant is placed into service.

FPL does not recover its capital investment in the EPU project until systems or components are placed in service, and even then, such base rate recovery does not reimburse FPL immediately. Rather, the substantial sums FPL is expending (to purchase equipment, pay vendors, etc.) will be recovered over the lives of the uprated units or lives of the systems placed into service.

Q. Please describe the process by which FPL recovers the Uprate plant in-service subsequent to the year it is placed into service.

A. In accordance with Nuclear Cost Recovery Rule No. 25-6.0423 (7), costs to be recovered subsequent to the year plant is placed into service are to be requested in a petition for Commission approval of the base rate increase related to the plant. On September 19, 2011 FPL filed a request to recover in base rates in 2012 the annualized base rate revenue requirements related to the Uprate modifications placed into service in 2011, (along with a true-up of its 2010 plant placed into service) separate from its cost recovery clause petition, and received approval in Order No. PSC-11-0575-PAA-EI, Docket No. 110270-EI.

Q. Is FPL recovering any costs through the Nuclear Cost Recovery Clause in advance of incurring costs?

A. No. With respect to TP 6 & 7, FPL is recovering current costs necessary to pay vendors and personnel working now to obtain the licenses and permits needed for the project, as described by FPL Witness Scroggs. The amount FPL is recovering through the Nuclear Cost Recovery Clause in 2012 for Turkey Point 6 & 7 reflects work performed and expenses incurred through 2012. Cost recovery, therefore, reflects historical and contemporaneous expenses – not advanced recovery for future, unknown expenses.

For the EPU project, the timing considerations are the same. The amount FPL is currently recovering through the Nuclear Cost Recovery Clause in 2012 for the EPU project reflects work performed and expenses incurred through 2012. Because the EPU project is in the construction phase, FPL is only recovering carrying charges on its investment, O&M, and partial-year revenue requirements for those portions of the project that are placed into service – FPL does not recover its capital investment dollar-for-dollar. FPL's recovery of its capital investment will occur through base rate revenue increases over the lives of the uprated units or the plant placed into service.

Through 2011, FPL has invested approximately $1.3 billion in the EPU project, as compared to the approximately $149 million it has recovered through the

NCRC. As described by FPL Witness Jones, the EPU project is already providing increased output for FPL's customers, and will be completed in 2013.

Q. Please describe the NFR Schedules you are filing in this Docket.

A. FPL is filing its 2011 final True-up (T) Schedules in this docket to provide an overview of the financial aspects of our nuclear plant projects, outline the categories of costs and provide the calculation of detailed project revenue requirements. We are including for the TP 6 & 7 Project Site Selection and Preconstruction NFRs, and for the Uprates, Construction NFRs.

TURKEY POINT 6 & 7 2011 TRUE-UP

Site Selection

Q. Is FPL filing any NFRs related to TP 6 & 7 Site Selection costs?

A. Yes. FPL is filing the NFR schedules T-1, T-2, and T-3A described in FPL Witness Scroggs's testimony for TP 6 & 7 Site Selection costs.

Q. What are FPL's 2011 actual TP 6 & 7 Site Selection expenditures compared to the previous Actual/Estimated costs?

A. FPL's TP 6 & 7 Site Selection expenditures ceased with the filing of its need petition on October 16, 2007. All recoveries of site selection costs and resulting true-ups have been reflected in prior nuclear cost recovery filings. Accordingly, the true-up of costs and resulting revenue requirements each equal zero.

Q. What are FPL's 2011 TP 6 & 7 Site Selection actual carrying charges compared to the previous Actual/Estimated carrying charges and any resulting over/underrecovery of costs?

A. The calculation of FPL's 2011 actual TP 6 & 7 Site Selection carrying charges on the deferred tax asset are $171,052 as shown in Exhibit SDS-1, schedule T-3A. FPL's previous Actual/Estimated carrying costs on the deferred tax asset were $171,052. The deferred tax asset is created by the recovery of Site Selection costs and the payment of income taxes before a deduction for the costs is allowed for income tax purposes. Since FPL no longer incurs Site Selection costs other than the return on the deferred tax asset, there is no true-up of 2011 costs needed.

Preconstruction

Q. Is FPL filing any NFRs related to 2011 TP 6 & 7 Project Preconstruction costs?

A. Yes. FPL is filing the NFR schedules T-1 through T-7B as described in FPL Witness Scroggs's testimony for the final True-up of TP 6 & 7 Preconstruction costs.

Q. What revenue requirement amount is FPL requesting to reflect the true-up of its 2011 TP 6 & 7 Preconstruction costs?

A. FPL is requesting to include in its 2013 CCRC charge an overrecovery of $15,372,530 in revenue requirements, which represents an overrecovery of Preconstruction costs of $14,629,595, and an overrecovery of carrying charges of

$742,934 as shown on Exhibit WP-1 and in the calculations in Exhibit SDS-1, Schedule T-2 and T-3A. The overrecovery of $15,372,530 will reduce the CCRC charge paid by customers when the CCRC is reset for 2013.

Q. What are FPL's 2011 actual TP 6 & 7 Preconstruction expenditures compared to costs previously Actual/Estimated and any resulting over/under recoveries of costs?

A. FPL's actual TP 6 & 7 Preconstruction expenditures for the period January through December 2011 are $23,150,979, ($22,877,378 on a jurisdictional basis) as presented in FPL Witness Scroggs's testimony and provided on SDS-1, Schedule T-6. FPL's Actual/Estimated 2011 Preconstruction expenditures were $37,955,536 ($37,506,973 on a jurisdictional basis). The result is an overrecovery of Preconstruction revenue requirements of $14,629,595.

Q. What are FPL's 2011 actual TP 6 & 7 Preconstruction carrying charges compared to carrying charges previously Actual/Estimated and any resulting over/under recoveries of costs?

A. FPL's 2011 actual TP 6 & 7 Preconstruction carrying charges are ($1,555,615). FPL's previous Actual/Estimated carrying charges were ($812,681), resulting in an overrecovery of revenue requirements of $742,934. The calculations of the carrying charges can be found in Exhibit SDS-1, Schedules T-2 and T-3A.

UPRATE 2011 TRUE-UP

Q. Is FPL filing any NFRs related to its 2011 Uprate costs?

A. Yes, FPL is filing the NFR schedules T-1 through T-7B as described in FPL Witness Jones's testimony for the final True-up of 2011 Uprate costs as shown in Exhibit TOJ-1.

Q. What revenue requirement amount is FPL requesting to reflect the true-up of its 2011 Uprate Project costs?

A. FPL is requesting to include an overrecovery of $394,941 in revenue requirements, which represents an underrecovery of carrying costs of $7,299,217, an overrecovery of O&M and interest costs of $679,375 and an overrecovery of base rate revenue requirements and carrying costs of $7,014,783 as shown on Exhibit WP-1. This net overrecovery of $394,941 will reduce the CCRC charge paid by customers when the CCRC is reset for 2013.

Q. What are FPL's 2011 actual Uprate Project expenditures compared to expenditures previously Actual/Estimated?

A. FPL's actual Uprate generation and transmission expenditures for the calculation of carrying costs, for the period January through December 2011 are $666,684,324, total company. As presented in FPL Witness Jones's testimony and shown on Exhibit TOJ-1, Schedule T-6 deducts the portion of this total for which the St. Lucie Unit 2 participants are responsible and then applies the retail jurisdictional factor to the remainder. This results in jurisdictional, net of participants Uprate generation and transmission expenditures of $640,057,608.

For the calculation of actual carrying charges further adjustments are made to present the expenditures on a cash basis (i.e., excluding accruals and pension and welfare benefit credits) and results in the expenditures shown on Exhibit TOJ-1, T-3 for the calculation of carrying charges of $621,131,017. These adjustments are necessary in order to comply with the Commission's practice regarding Allowance for Funds Used During Construction (AFUDC) accruals.

Q. Where can the calculation of FPL's Uprate Project 2011 actual carrying charges be found?

A. The calculation of the Uprate Project actual carrying charges on construction expenditures and on the deferred tax liability of $77,586,524 are shown in Exhibit TOJ-1, Schedules T-3 and T-3A, respectively. FPL's previous Actual/Estimated 2011 Uprate carrying charges were $70,287,307. As a result of the final true-up of 2011 carrying charges in this March 1, 2012 filing, there is an underrecovery of $7,299,217 in 2011.

Q. What are FPL's Uprate Project 2011 actual recoverable O&M costs?

A. FPL's Uprate Project 2011 actual recoverable O&M costs including interest are $12,172,529 ($11,584,442 jurisdictional, net of participants), the calculation of which can be found in Exhibit TOJ-1, Schedule T-4. FPL's previous Actual/Estimated 2011 Uprate Project recoverable O&M including interest was $12,721,405 ($12,263,818 jurisdictional, net of participants). As shown in schedule T-4, over/under recoveries of recoverable O&M incur interest at the 30-day dealer commercial paper rate reported in the Wall Street Journal through August 31, 2011. Since that time FPL has been using the AA Financial 30-day rate posted on the Federal Reserve website as comparable to the previously used 30-day dealer commercial paper rate, which is no longer published. As a result of the actual final true-up of 2011 Uprate Project recoverable O&M including interest, there is an overrecovery of $679,375, jurisdictional, net of participants in 2011.

Q. Please describe the calculation of base rate revenue requirements.

A. As described in Order No. PSC-08-0749-FOF-EI in Docket No. 080009-EI, FPL "shall be allowed to recover through the NCRC associated revenue requirements for a phase or portion of a system placed into commercial service during a projected recovery period. The revenue requirement shall be removed from the Nuclear Cost Recovery Clause (NCRC) at the end of the period. Any difference in recoverable costs due to timing (projected versus actual placement in service) shall be reconciled through the true-up provision". Until the plant goes into service, FPL will continue to recover the carrying charges on the construction costs. Effective in the month each transfer to plant in-service is made, FPL will transfer the related costs from Construction Work in Progress (CWIP) to plant in-service. For plant placed into service less than $10 million, carrying charges will be calculated for half a month and base rate revenue requirements will be calculated for half a month. For plant placed into service greater than $10 million, the calculation of carrying charges and base rate revenue requirements are to the day the plant is placed into service. Subsequent to the month the plant is placed into service, carrying charges cease and the 2011 base rate revenue requirements related to the plant going into service is included for recovery through the NCRC. Included in the base rate revenue requirement is any non-incremental labor related to the Uprate Project. FPL's 2011 actual transfers to plant in service, including non-incremental labor, are shown in Exhibit WP-3.

Q. Where can the calculation of the base rate revenue requirements for plant being placed into service in 2011 for the Uprate Project be found?

A. Uprate Project actual base rate revenue requirements for plant being placed into service in 2011 of $9,825,669, or $9,138,802 including carrying charges of ($686,867), are shown in Exhibit WP-1. FPL's previous Actual/Estimated 2011 base rate revenue requirements were $16,585,797, or $16,153,585 net of carrying charges of ($432,212). As a result of the true-up of actual 2011 Uprate Project base rate revenue requirements, including carrying charges, there is an overrecovery of $7,014,783 as shown on my Exhibit WP-1. The plant being placed into service and the calculation of the base rate revenue requirements is shown in Exhibit WP-3 and the carrying charge in Exhibit TOJ-1, Appendix B. The carrying charges on the over/underrecoveries of the base rate revenue requirement compared to prior Actual/Estimated are shown in Appendix C in TOJ-1.

Q. What is the total of FPL's 2011 actual transfers to plant in-service for the Uprate Project in 2011?

A. In 2011, FPL's actual transfers to plant in service total $164,575,211 ($146,881,977, jurisdictional, net of participants), as shown on TOJ-1, Appendix A. The 2011 Actual/Estimated transfers to plant in service were $242,223,012,

($220,437,506, jurisdictional, net of participants). A description of the plant placed into service in 2011 is found in FPL Witness Jones's testimony.

Q. What caused the difference between 2011's base rate revenue requirements in the AE schedules and the base rate revenue requirements in the T schedules for the Uprate modifications placed into service?

A. The 2011 AE Schedules reflect FPL's estimate that Uprate modifications of $242,223,012 ($220,437,506 jurisdictional, net of participants) would be placed into service in 2011. The actual plant placed into service during 2011 was $164,575,211 ($146,881,977 jurisdictional, net of participants), which is reflected in my Exhibit WP-3. The plant placed into service in 2011 and the revised in-service dates are also shown in Exhibit WP-3. FPL Witness Jones addresses the actual plant placed into service in 2011 in his testimony.

In the AE schedules, FPL used its then most current rate of return which was based on the December 2010 Surveillance Report. The rate of return in our 2011 T schedules is the rate of return based on the most current 2011 monthly surveillance reports at the time the Uprate modifications are placed into service. This is in accordance with the requirements of the Nuclear Cost Recovery Rule No. 25-6.0423 Section 7 (d). The reasons for the changes related to the plant planned to be placed into service are explained in greater detail in FPL Witness Jones's testimony.

Q. What accounting and regulatory treatment is provided for costs that would have been incurred regardless of the Uprate Project?

A. Costs that would have been incurred regardless of the Uprate Project are not included in FPL's NCRC calculations. Such expenditures that are not "separate and apart" from the nuclear Uprate Project will be accounted for under the normal process for O&M and capital expenditures. Capital expenditures will accrue AFUDC while in CWIP until the system or component is placed into service. Only costs incurred for activities necessary for the Uprate Project are charged to the Uprate work orders/internal orders and included as recoverable O&M or as construction costs included in the calculation of carrying charges in the NFR schedules. This method ensures that FPL only receives recovery of the appropriate recoverable O&M or carrying charge return currently under the Nuclear Cost Recovery Rule and expenses or accrues the appropriate O&M or AFUDC return on costs that are not "separate and apart" that will be recovered through rate base when the project is placed into service. FPL employs a rigorous, engineering-based process to segregate costs that are "separate and apart" from those that would have normally been incurred, so that only the appropriate costs are reflected in the NCRC request. This process is discussed in more detail in FPL Witness Jones's March 1, 2012 testimony.

ACCOUNTING CONTROLS

Q. Please describe the accounting controls FPL relies upon to ensure proper cost recording and reporting for these projects.

A. FPL relies on its comprehensive corporate and overlapping business unit controls for recording and reporting transactions associated with any of its capital projects including the Uprate Project and TP 6 & 7. These comprehensive and overlapping controls include:

- FPL's Accounting Policies and Procedures;
- Financial systems and related controls including FPL's general ledger and construction asset tracking system (CATS or PowerPlant);
- FPL's annual budgeting and planning process;
- Reporting and monitoring of plan costs to actual costs incurred; and
- Business Unit specific controls and processes.

The project controls are further discussed in the March 1, 2012 testimony of FPL Witnesses Scroggs and Jones.

Q. Are there any changes to existing accounting controls or additional accounting controls implemented and relied upon for these projects and the related reporting for 2011?

A. No. However, as I discuss later in my testimony, FPL did implement a new general ledger system and an updated version of its construction asset tracking system.

Q. Are these controls documented, assessed and audited and/or tested on an ongoing basis?

A. Yes. The FPL corporate accounting policies and procedures are documented and published on the Company's internal website, Employee Web. In addition, accounting management provides formal representation as to the continued compliance with those policies and procedures each year. Sarbanes-Oxley processes are identified, documented, tested and maintained, including specific processes for planning and executing capital work orders, as well as acquiring and developing fixed assets. Certain key financial processes are tested during the Company's annual test cycle. The Company's external auditor, Deloitte & Touche, LLP, as a part of its annual audit, which includes assessing the Company's internal controls over financial reporting and testing of general computer controls, expresses an opinion as to the effectiveness of those controls.

Q. Describe the responsibilities and accounting controls of the New Nuclear Accounting Project Group.

A. The primary responsibility of the New Nuclear Accounting Project Group is to provide financial accounting guidance for the recovery of costs under the Nuclear Cost Recovery Rule. Additional responsibilities include the preparation and maintenance of the NFR schedules, (i.e., T, AE, P, and TOR Schedules) and on a monthly basis, ensuring the costs included in the NFR schedules are recorded to the financial records of the Company and reconciled to the NFRs. The Nuclear Cost Recovery projects utilize unique work orders/internal orders to capture costs directly related to these projects. After ensuring accurate costs are recorded, adjustments are made to reflect participants' credits, jurisdictionalize the costs, and include other adjustments required in the NFR schedules. Monthly journal entries are prepared to reflect the effects of the recovery of these costs and monthly reconciliations of the NFR accounts are performed. The resulting schedules are included in our Nuclear Cost Recovery filings and described in testimony.

The New Nuclear Accounting Project Group works closely with the Nuclear Business Unit, Engineering, Construction & Corporate Services Division (ECCS), and the Transmission Business Unit to address issues surrounding the costs related to the projects. This involves researching, providing direction and resolving project accounting issues that arise as the new nuclear and uprate projects develop.

TURKEY POINT 6 & 7 SPECIFIC ACCOUNTING CONTROLS

Q. Describe the role of the Engineering, Construction & Corporate Services (ECCS) Division related to the TP 6 & 7 Project.

A. The ECCS Division has a Project Controls Group that reports through the Vice President of ECCS and provides structural leadership, governance and oversight for the project. On a monthly basis, the group completes a thorough review of all costs ensuring accuracy of the charges posted to the project. Additionally, Project Controls prepares monthly variance reports, identifying variances against budgeted information. Team members and project management meet monthly to review and understand existing budget variances against the projected forecast. The Group consists of a Director of Construction with an economics degree and 30 years experience at FPL, 22 years in the ECCS and Nuclear Business Units and 8 years in the Auditing, Property and Financial Accounting Groups. He is supported by staff with business, finance and accounting degrees and nuclear and construction experience.

Q. **Describe the Engineering, Construction & Corporate Services Division accounting controls which ensure costs are appropriately incurred for the TP 6 & 7 Project.**

A. When FPL filed its Need Determination in October 2007, costs related to the project recorded in a deferred debit account were transferred to CWIP. A separate work order was set up for Site Selection costs and Preconstruction costs. As stated in the Rule, a site is deemed to be selected upon the filing of a petition for a determination of need; therefore, all costs expended prior to the Need Filing are categorized as Site Selection costs. All Site Selection expenditures have been determined prudent by this Commission in Order No. PSC-08-0749-FOF-EI and all recoveries (other than carrying costs on the deferred tax asset) with resulting true-ups have been reflected in previous filings. Preconstruction costs are costs expended after a site has been selected, captured in a unique work order/internal order, and are included in the Preconstruction T Schedules for actual costs incurred in each year.

Q. **Describe the Engineering, Construction & Corporate Services Division accounting controls which ensure costs are appropriately charged to the TP 6 & 7 Project with the implementation of SAP.**

A. When a potential expenditure greater than $5,000 is identified, project personnel will route the relevant information detailing the need, justification, estimated cost and documentation for the request to the Project Controls Group for review. Upon verification of the documentation and availability of budgeted resources, the Project Controls Group will electronically advise the requestor of the appropriate internal order and cost element for charging. The requester will then create a "shopping cart" in the Integrated Supply Chain (ISC) module of SAP, attaching the aforementioned documentation including the electronic notification from the Project Controls Group. This information is sent electronically through the shopping cart system to the ISC agent of the functional area who verifies the appropriate documentation is attached to the shopping cart. Upon verification, a Purchase Order (PO) is initiated by the ISC agent and forwarded with the attachments to the applicable Director for review to ensure the expenditure is appropriate and relevant to the project. If the Director is in agreement with the expenditure, he will electronically approve the PO and a notification will be sent to the issuing ISC agent. The ISC agent will then electronically issue to the vendor a PO available for charging, copying the original requestor, the Project Controls Group and the approving Director. After the goods have been received or services have been rendered, an invoice is received by the functional area, it is reviewed, and if determined to be appropriate, approved based on FPL Approval Authorization amounts. Approved invoices are then forwarded to the Invoice Processor and upon verification of the approvals and account coding; the invoice is entered into the SAP system for processing and payment to the vendor.

Currently, the majority of expenditures are for one vendor (Bechtel), which is handling the Combined Operating License Application (COLA), and supporting the site certification application. The invoices from this and other vendors which can be quite voluminous are received electronically by the Project Controls Group. They are loaded into a Share Point database and routed to the appropriate business unit contacts to assess, review and approve where appropriate. The Project Controls Analyst ensures all parties have signed off on their appropriate section of the invoice checklist approval form prior to payment. The invoices are also reviewed for compliance with the purchase order and/or contract and differences with vendors are resolved. The remaining invoices relate to charges incurred by groups such as Legal, Marketing and Communications, Transmission, and Environmental Services.

Q. **Describe the review and reporting performed by the ECCS Project Controls organization related to the TP 6 & 7 Project.**

A. The Project Controls organization is responsible for preparing, analyzing and clearly and concisely explaining variances against planned budgets for current month, year-to-date and year end. Project Controls holds monthly meetings with team members and project management to review and understand existing budget variances and any projected variances. Project Controls provides the resulting expenditures to Accounting for inclusion in the NFR schedules.

UPRATE SPECIFIC ACCOUNTING CONTROLS

Nuclear Business Unit Accounting Controls

Q. Describe the oversight role of the Nuclear Business Operations (NBO) Group related to the Uprate Project.

A. The NBO Group is independent of the EPU Project Team and provides oversight of the costs charged to the Uprate Project. The NBO Group is primarily responsible for the work order/internal order maintenance function, reviewing payroll to ensure only appropriate payroll is charged to the Uprates, determining appropriate accounting for costs, raising potential issues to the Property Accounting Group when necessary, providing accounting guidance and training to the Uprate team, assisting with internal and external audit-related matters, reviewing project projections and producing monthly variance reports.

Q. Describe the NBO Group accounting controls which ensure costs are appropriately incurred and tracked for the Uprate Project.

A. The NBO Group accounts for the activities necessary to perform the Uprates at the four nuclear units, Turkey Point Units 3 and 4 and St. Lucie Units 1 and 2. Costs associated with the work performed on components defined as a property retirement unit will be transferred from CWIP to plant in service at the end of each outage or when they become used and useful (e.g., such as the modifications to the St. Lucie Unit 2 Turbine Gantry Crane). In order to facilitate this process, a separate budget activity/work breakdown structure was set up for each unit along with capital work orders/internal orders to capture costs related to each Uprate outage. Additional work orders/internal orders are set up, as necessary, to capture costs associated with plant placed into service at a different time than the outages (e.g. turbine gantry cranes, generator step-up transformers, etc.).

Q. Describe the NBO Group accounting controls which ensure costs are appropriately charged to the Uprate Project.

A. Invoices are routed to the St. Lucie or Turkey Point site project controls analyst, as appropriate. The analyst checks the invoices for accuracy and for agreement to the PO terms and conditions. Once the invoice has been appropriately verified, the analyst records invoice information on an Invoice Tracking Log. The Invoice Approval/Route List is then routed for verification of receipt of goods/services and all required approvals. Before payment can be made on any invoice greater than $1 million, the approval of the Vice President, Nuclear Power Uprates is required. Before payment can be made on any invoice greater than $5 million, the approval of the Executive Vice President & Chief Nuclear Officer is required. Once all necessary approvals have been obtained, the project controls analyst processes the invoice for payment in NAMS (Nuclear Asset Management System) against the respective purchase order. Extended Power Uprate Project Instruction Number EPPI-230, *Project Invoice*, details the flow of the invoice through the approval, receipt and payment process at the sites and establishes responsibilities at each stage of the process.

Q. Describe the review performed by the EPU Project Controls Team and the NBO Group related to the Uprate Project.

A. Throughout the month, general ledger detail transactions are monitored by the EPU Project Controls Team and NBO to ensure that costs charged to the Uprates are appropriate and are accurately classified as capital or O&M. Site cost engineers perform reviews to ensure invoices are accurately coded to the appropriate activity/scope work order/internal order. NBO reviews internal labor costs to ensure that only appropriate payroll is charged to the Uprates. In addition, all steps in this process are subject to internal and external audits and reviews.

The Project engineers and NBO work together closely to make sure the costs are appropriate and are accurately classified as capital or O&M. Construction Leads perform reviews to ensure invoices are accurately coded to the appropriate activity/scope work order/internal order.

Q. Describe the reporting performed by the EPU Project Controls Team and the NBO Group related to the Uprate Project.

A. The Uprate Project Controls Director, along with the Uprate Project Controls Teams at each site, records schedule changes, project delays, and project costs. The Uprate Project Controls Director, along with the Uprate Project Controls Team, supports risk management and contract administration.

The NBO Group drafts monthly variance reports that compare actual expenditures incurred to the originally estimated budget and reports year end forecast estimates. The draft reports are sent to the St. Lucie and Turkey Point Uprate Project Controls Teams responsible for providing variance explanations and forecast updates to NBO. The reports are reviewed by the Uprate Project control supervisors and management prior to the submission to NBO. NBO reviews the variance explanations and forecast numbers for reasonableness and accuracy prior to compilation and inclusion in the Nuclear Business Unit corporate monthly variance report submitted to the Corporate Budget Group. NBO is also responsible for reviewing numbers reported to the FPL Executive Steering Committee to ensure consistency with corporate variance reports and for providing the Accounting Department with project amounts for inclusion in the NFR schedules.

Transmission Business Unit Accounting Controls

Q. Describe the role of the Transmission Business Unit related to the Uprate Project.

A. The Transmission Business Unit is incurring expenditures related to the Uprate Project in order to perform substation and transmission line engineering, procurement, and construction on specific work orders/internal orders assigned to projects which resulted from transmission interconnection and integration studies performed by FPL Transmission Planning. These studies were based on incorporating the additional megawatts to be generated by the uprated nuclear units at St. Lucie 1 & 2 and Turkey Point 3 & 4 into the FPL transmission system. The Transmission Business Unit cost and performance team ensures costs are appropriately incurred and charged to the Uprate Projects. The Transmission Business Unit reviews payroll to ensure only appropriate payroll is charged to the Uprate Project, determines appropriate accounting for costs, raises potential issues to the Property Accounting Group when necessary, provides accounting guidance and training to the Uprate Project team, assists with internal and external audit-related matters, reviews project projections, and produces monthly variance reports. Transmission related work for the Uprate project is also being accounted for by work order/internal order based on the scope of work and will be placed into service when the respective work is used and useful.

Q. Describe the Transmission Business Unit accounting controls which ensure costs are appropriately incurred and tracked for the Uprate Project.

A. The Transmission Business Unit identifies the transmission activities necessary to support the increased electrical output of the Uprates at the four nuclear units, St. Lucie Units 1 & 2 and Turkey Point Units 3 & 4. Costs associated with the work performed for each outage are transferred from CWIP to plant in service by Property Accounting as necessary. In order to facilitate this process and identify activities, two separate budget activities/work breakdown structures were set up with appropriate sub activities and multiple work orders/internal orders. Purchase Orders are handled by ISC via the Shopping Cart Process. A Shopping Cart PO request is routed from the originator to all approvers required based on the dollar amount of the PO. The PO Requisitioning group determines the required approvals based on the business unit's PO approval limits, and routes the request as required. Once all required approvals are secured, the PO will be created based on the information in the Shopping Cart request.

Q. Describe the Transmission Business Unit accounting controls which ensure costs are appropriately charged to the Uprate Project.

A. Invoices are routed to the Transmission Project Control Administrator (Administrator). The Administrator checks the invoices for accuracy and for agreement to the PO terms and conditions. Once the invoice has been appropriately verified, the Administrator records invoice information on the Cost Control Tracking sheet and routes the invoice for all required approvals. Invoices found to contain any inaccuracies are returned to the requestor for revisions. Any invoice greater than $1 million requires the approval of the Business Unit Vice President. Any invoice greater than $5 million requires the approval of the FPL President & Chief Executive Officer before payment is made. Once all necessary approvals have been obtained, the Administrator processes the invoice for payment in SAP against the respective purchase order.

Q. Describe the additional reviews performed by the Transmission Business Unit related to the Uprate Project.

A. The Cost & Performance Analyst updates the Turkey Point and St Lucie Uprate Cost reports on a monthly basis for actual costs incurred. The Turkey Point and St Lucie Uprate Cost reports are then reviewed by the assigned Project Managers and Administrators who work closely together to ensure that all costs are appropriately charged to the Uprate Project and are accurately classified as either Capital or O&M. Construction Leaders also perform reviews to ensure all invoices are accurately assigned and coded to the appropriate work order/internal order for the Uprate Project as well. Any discrepancies identified as a result of these reviews are resolved at this time. The assigned Project Manager then updates the individual work order/internal order forecasts, if warranted.

Q. Describe the reporting performed by the Transmission Business Unit related to the Uprate Project.

A. The Transmission Cost & Performance group drafts monthly variance reports that compare actual expenditures incurred to the originally estimated budget and reports year end forecast estimates. These Corporate monthly variance reports are reviewed by the assigned Project Manager for reasonableness and accuracy and the final is then submitted to the Corporate Budget Group.

ADDITIONAL NEW NUCLEAR AND UPRATE ACCOUNTING OVERSIGHT

Q. Are there any additional controls implemented and relied upon for these Projects and the related reporting?

A. Yes. The Company has issued specific guidelines for charging costs to the project work orders/internal orders. These guidelines emphasize the need for particular care in charging only incremental labor to the project work orders/internal orders included for nuclear cost recovery and ensure consistent application of the Company's capitalization policy. These guidelines describe the process for the exclusion of non-incremental labor from current NCRC recovery while providing full capitalization of all appropriate labor costs through the implementation of separate project capital work orders/internal orders that will be included in future non-NCRC base rate recoveries. Exhibit WP-4 provides a flowchart depicting this process for 2011.

Q. Did the guidelines for charging costs to the project work orders/internal orders change from 2010 to 2011?

A. No. The guidelines in effect in 2010 apply to 2011. As a result of FPL's rate case (Docket No. 080677-EI), the Company reset the basis upon which incremental employee labor is established in determining which employees are clause recoverable. Starting in 2010, personnel previously determined non-incremental became incremental and eligible to record labor to NCRC work orders/internal orders. Any employee dedicated to the Project and charging 100% of his time to the NCRC during 2010 is considered incremental for the entire year 2010. Any employee that charged a percentage of his time to capital in the NCRC in 2010 will be designated incremental for that percentage of his costs. This became the basis for determining incremental payroll in 2011.

Q. What is the purpose of the continuous internal audits conducted by FPL on the TP 6 & 7 and Uprate Projects?

A. The Company continues to undergo specific project related internal audits. The objective of these audits is to test the propriety of expenses charged to the NCRC to ensure they are recoverable project expenses and to ensure compliance with the Commission's Rule. Any potential process improvements identified during the audits are communicated to management to further enhance internal controls. FPL will continue to ensure these projects are audited on an ongoing basis. The 2011 costs and controls related to the TP 6 & 7 and the Uprate Projects will have been audited prior to the start of the hearing in this docket. These audits will continue to provide assurance that the internal controls surrounding transactions and processes are well established, maintained and communicated to employees, and provide additional assurance that the financial and operating information generated within the Company is accurate and reliable.

Q. Please comment on the overall level of control and oversight of the NCRC process.

A. The ongoing cycles of cost collection, aggregation, analysis and review which lead to the NFR filings provide for a level of detailed review that is unprecedented. For example, in the preparation of the NFR schedules, transactional expenditures are projected by activity and an immediate review of projection to actual, in many cases at the transactional level, is conducted. The nature of the data collection and aggregation process, along with the calculation of carrying charges and construction period interest, provides an increased level of detailed review. The requirements of the Rule have, by design, significantly increased the review and transparency of the costs themselves.

Q. Was a new general ledger system implemented?

A. Yes. In July 2011, FPL successfully implemented a new general ledger system (SAP) to replace its previous general ledger system (Walker). To facilitate the conversion, also in July 2011, FPL implemented a new version of its fixed asset system (previously referred to as CATs but with the new version renamed to PowerPlant). As a result, work orders for the New Nuclear and Uprate Projects in Walker and CATs were converted to internal orders in SAP and PowerPlant.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Power Plant)
Costs Recovery Clause)

DOCKET NO. 120009-EI
FILED: June 11, 2012

ERRATA SHEET

APRIL 27, 2012 TESTIMONY AND EXHIBITS OF WINNIE POWERS

APRIL 27, 2012 TESTIMONY OF WINNIE POWERS

PAGE #	LINE #	
Page 3	Line 1	Change "$150,739,659" to "$151,491,402"
Page 3	Line 17	Change "$150,739,659" to "$151,491,402"
Page 3	Line 19	Change "($15,767,471)" to "($15,102,473)"
Page 3	Line 20	Change "$46,300,768" to "$46,349,770"
Page 3	Line 21	Change "$120,206,363" to "$120,244,105"
Page 9	Line 13	Change "$150,739,659" to "$151,491,402"
Page 9	Line 15	Change "($15,767,471)" to "($15,102,473)"
Page 9	Line 15	Change "$46,300,768" to "$46,349,770"
Page 9	Line 16	Change "$120,206,363" to "$120,244,105"
Page 13	Line 14	Change "$990,524,170" to "$990,590,949"
Page 13	Line 20	Change "$45,566,270" to "$45,615,272"
Page 14	Line 5	Change "$198,482,692" to "$198,531,694"
Page 14	Line 6	Change "$45,566,270" to "$45,615,272"
Page 14	Line 9	Change "$45,566,270" to "$45,615,272"
Page 14	Line 11	Change "$45,566,270" to "$45,615,272"
Page 14	Line 11	Change "$37,596,272" to "$37,645,274"
Page 14	Line 18	Change "$104,860,725" to "$104,909,726"
Page 14	Line 22	Change "$37,596,272" to "$37,645,274"
Page 17	Line 21	Change "$85,212,207" to "$85,249,950"
Page 17	Line 22	Change "$15,396,136" to "$15,433,878"
Page 18	Line 6	Change "$15,396,136" to "$15,433,878"
Page 19	Line 3	Change "$130,383,536" to "$131,135,279"
Page 19	Line 6	Change "($394,942)" to "$270,057"
Page 19	Line 7	Change "$45,566,270" to "$45,615,272"
Page 19	Line 8	Change "$85,212,207" to "$85,249,950"
Page 22	Line 6	Change "$150,739,659" to "$151,491,402"
Page 22	Line 8	Change "($15,767,471)" to "($15,102,473)"
Page 22	Line 10	Change "$46,300,768" to "$46,349,770"
Page 22	Line 11	Change "$120,206,363" to "$120,244,105"

PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WINNIE POWERS

DOCKET NO. 120009-EI

April 27, 2012

Q. Please state your name and business address.

A. My name is Winnie Powers. My business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as New Nuclear Accounting Project Manager.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. Are you sponsoring or co-sponsoring any Exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit WP-5, 2013 Revenue Requirements, details the Revenue Requirements being recovered in 2013. These amounts include the results of the 2011 True-Up (T) Nuclear Filing Requirements Schedules (NFRs) filed in this docket on March 1, 2012 and the 2012 Actual/Estimated (AE), and 2013 Projected (P) NFRs FPL is now filing. The NFRs detail the components of cost by project, by year and by category of costs being recovered. For Turkey Point 6 & 7 (TP 6 & 7 or New Nuclear), this includes Site Selection costs, Preconstruction costs, and carrying costs on unrecovered balances and on the deferred tax asset/liability. For the Extended Power Uprate Project (EPU or Uprate Project), this includes carrying costs on construction costs and on the deferred tax asset/liability, recoverable operation and maintenance costs (O&M) including interest, and base rate revenue requirements, including carrying charges, for the year plant is placed into service.

- Exhibit WP-6, 2012 and 2013 Base Rate Revenue Requirements, details the revenue requirements for the Uprate plant modifications expected to be placed into service during 2012 (as updated for actual/estimated information) and during 2013 (as projected).

(I additionally sponsor or co-sponsor some of the NFRs included in Exhibits sponsored by FPL Witnesses Scroggs and Jones as described below.)

- Exhibit SDS-8, TP 6 & 7 Site Selection and Preconstruction NFRs, consists of 2012 AE Schedules, 2013 P Schedules, and 2013 True-up to Original (TOR) Schedules. The NFR Schedules contain a table of contents listing the schedules sponsored and co-sponsored by FPL Witness Scroggs and me, respectively.
- Exhibit TOJ-14, Uprate NFRs, consists of 2012 AE Schedules, 2013 P Schedules, and 2013 TOR Schedules. The NFR Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Jones and me, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the $150,739,659 revenue requirements that FPL is requesting to recover through the Capacity Cost Recovery Clause (CCRC) in 2013. These revenue requirements are summarized in my Exhibit WP-5 and shown in the NFR Schedules we are now filing in this docket. Included in these revenue requirements is our final true-up for the 2011 T schedules filed on March 1, 2012 in this docket. In addition, I provide an overview of the components of the revenue requirements included in FPL's filing and demonstrate the filing complies with the Florida Public Service Commission (FPSC or Commission) Rule No. 25-6.0423, Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery (Nuclear Cost Recovery Rule or NCR Rule). I also explain how carrying charges are provided for under the Nuclear Cost Recovery Rule, describe the base rate revenue requirements included for recovery in the schedules and discuss the accounting controls FPL relies upon to ensure only appropriate costs are charged to the projects.

Q. Please summarize your testimony.

A. FPL is requesting to recover $150,739,659 in revenue requirements in 2013. These revenue requirements are based on:

(1) The final true-up of 2011 costs of ($15,767,471);

(2) The actual/estimated true-up of 2012 costs of $46,300,768; and

(3) The projection of 2013 costs of $120,206,363.

My testimony includes the exhibits and NFRs needed to support the true-up of the 2012 AE schedules and the 2013 P schedules.

My testimony describes FPL's April filings under the Nuclear Cost Recovery Rule and the robust and comprehensive corporate and overlapping business unit controls for incurring and validating costs and recording transactions associated with FPL's TP 6 & 7 and Uprate Projects. Throughout my testimony, I refer to exhibits and NFR schedules that provide an overview of the 2013 revenue requirements FPL is requesting to recover.

NUCLEAR FILING REQUIREMENT SCHEDULES

Q. Please describe the NFR Schedules you are filing in this Docket.

A. FPL is filing its 2012 AE, 2013 P, and 2013 TOR Schedules in this docket consistent with the requirements of the NCR Rule to provide an overview of the financial and construction aspects of its nuclear power plant projects, outline the categories of costs represented, and provide the calculation of detailed project revenue requirements. FPL previously filed its 2011 T Schedules on March 1, 2012 in this docket. My testimony refers to Exhibits that include the 2012 AE Schedules, 2013 P Schedules, and the 2013 TOR Schedules. The 2013 TOR Schedules provide an updated summary of the project costs through 2013.

Q. Please generally describe the types of costs that FPL is seeking recovery of in this docket.

A. With respect to TP 6 & 7, FPL is seeking recovery of current costs necessary to pay vendors and personnel working now to obtain the licenses and permits needed for the project, as described by FPL Witness Scroggs. These costs are preconstruction costs.

Because the EPU project is in the construction phase, FPL is recovering carrying charges on its investment, O&M, and partial-year revenue requirements for those portions of the project that are placed into service – FPL does not recover its capital investment dollar-for-dollar. FPL will recover its capital investment through base rates over the lives of the uprated units or the plant that is placed into service. As described by FPL Witness Jones, the EPU project is already providing increased output for FPL's customers, and will be completed in 2013.

Q. Does the Nuclear Cost Recovery Rule describe the annual filing requirements that a utility must make in support of its current year (2012) expenditures for Commission review and approval?

A. Yes. The Nuclear Cost Recovery Rule states:

" 1. Each year, a utility shall submit, for Commission review and approval, as part of its Capacity Cost Recovery Clause filings: …

b. True-Up and Projections for Current Year. By May 1, a utility shall submit for Commission review and approval its Actual/Estimated true-up of Projected pre-construction expenditures based on a comparison of current year Actual/Estimated expenditures and the previously-filed estimated expenditures for such current year and a description of the pre-construction work projected to be performed during such year; or, once construction begins, its Actual/Estimated true-up of Projected carrying costs on construction expenditures based on a comparison of current year Actual/Estimated carrying costs on construction expenditures and the previously filed estimated carrying costs on construction expenditures for such current year and a description of the construction work projected to be performed during such year."

Q. Is FPL complying with these requirements with respect to its 2012 Actual/Estimated TP 6 & 7 and Uprate Project costs?

A. Yes. FPL has included for TP 6 & 7 the 2012 AE Schedules in Exhibit SDS-8 for Site Selection and Preconstruction costs. FPL has included for the Uprate Project the 2012 AE Schedules in Exhibit TOJ-14. These schedules include two months of actual costs and ten months of estimated costs. In their testimonies, FPL Witness Scroggs for the TP 6 & 7 Project and FPL Witness Jones for the Uprate Project provide the reasons why these actual/estimated costs and resulting true-ups are reasonable.

Q. Does the Nuclear Cost Recovery Rule describe the annual filing requirements that a utility must make for the projected year (2013) expenditures for Commission review and approval?

A. Yes. The Nuclear Cost Recovery Rule states:

" 1. Each year, a utility shall submit, for Commission review and approval, as part of its Capacity Cost Recovery Clause filings: …

c. Projected Costs for Subsequent Years. By May 1, a utility shall submit, for Commission review and approval, its Projected pre-construction expenditures for the subsequent year and a description of the pre-construction work projected to be performed during such year; or, once construction begins, its Projected construction expenditures for the subsequent year and a description of the construction work projected to be performed during such year."

Q. Is FPL complying with these requirements with respect to its 2013 Projected TP 6 & 7 Project and Uprate Project costs?

A. Yes. FPL has included for TP 6 & 7 the 2013 P Schedules in Exhibit SDS-8 for Site Selection and Preconstruction costs. FPL has included for the Uprate Project the 2013 P Schedules in Exhibit TOJ-14. In their testimonies, FPL Witness Scroggs for the TP 6 & 7 Project and FPL Witness Jones for the Uprate Project, provide the reasons why the 2013 projected costs are reasonable. My Exhibit WP-5, details the true up of 2011 actuals (as filed on March 1, 2012 in this docket), the 2012 actual/estimated and the 2013 projected costs and revenue requirements FPL is filing now and requesting to recover in 2013.

Q. How is FPL providing an update to the original TP Unit 6 & 7 Project and Uprate Project costs, respectively?

A. FPL has included for TP 6 & 7 the 2013 TOR Schedules in Exhibit SDS-8 for Site Selection and Preconstruction costs. FPL has included for the Uprate Project the 2013 TOR Schedules in Exhibit TOJ-14. The TOR Schedules follow the format of the T, AE, and P Schedules but also detail the actual to date project costs and projected total retail revenue requirements for the duration of the project based on the best available information prior to the filing, i.e., at the "freeze date" of the assumptions.

- Schedule TOR-1 - Reflects the jurisdictional amounts used to calculate the final true-up, actual/estimated true-up, projection, deferrals, and requested recovery amounts for each project included in the NCRC.
- Schedule TOR-2 – Reports the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate if necessary.
- Schedule TOR-3 - Provides a summary of the actual amounts through 2011 and projected total amounts for the project.
- Schedule TOR-4 - Provides the annual construction O&M expenditures by function as reported for all historical years through 2011, for the current year, and for the projected year.
- Schedule TOR-6 - Provides the actual expenditures through 2011 and projected annual expenditures by major tasks performed within Site Selection, Pre-Construction, and Construction for the project.
- Schedule TOR-6a - Provides a description of the major tasks performed within the Site Selection, Pre-construction, and Construction category for the year filed.

- Schedule TOR-7 - Reflects initial project milestones in terms of costs, budget levels, initiation dates, and completion dates as well as all revised milestones and reasons for each revision.

Q. What are the sunk costs that FPL is accounting for in the feasibility analysis?

A. As discussed in FPL Witness Dr. Sim's testimony, for TP 6 & 7, FPL is excluding in the feasibility analysis a total of approximately $157 million of sunk costs as of December 31, 2011. For the Uprate Project, FPL is excluding in the feasibility analysis a total of approximately $1.46 billion of sunk costs as of December 31, 2011.

Q. Please explain the components of the revenue requirements that FPL is requesting to include for recovery effective January 1, 2013.

A. The total amount FPL is requesting to recover in 2013 is $150,739,659. This amount reflects the true-up of 2011 actual costs as filed on March 1, 2012 of ($15,767,471), the true-up to 2012 actual/estimated costs of $46,300,768, and the recovery of 2013 projected costs of $120,206,363 as shown on Exhibit WP-5.

TURKEY POINT 6 & 7

Actual/Estimated Revenue Requirements - 2012

Q. What is the revenue requirement amount that FPL is requesting to reflect in the true-up of its 2012 TP 6 & 7 Costs?

A. FPL is requesting $734,498 in revenue requirements, which represents an underecovery of Preconstruction costs of $3,257,796, and an overrecovery of carrying charges of $2,523,298 as shown on Exhibit WP-5. This amount will be reflected in the CCRC charge paid by customers when the CCRC is reset in 2013. There is no true-up of 2012 Site Selection costs since there is only the recovery of carrying costs remaining on the deferred tax asset for Site Selection and no true-up is required. FPL's calculation of carrying costs on the deferred tax asset is $180,883 as presented on FPL Witness Scroggs's Exhibit SDS-8, Schedule AE-3A.

Q. What are FPL's 2012 actual/estimated TP 6 & 7 Preconstruction expenditures compared to costs previously projected and any resulting (over)/under recoveries of costs?

A. FPL's actual/estimated TP 6 & 7 Preconstruction expenditures for the period January through December 2012 are $34,907,426 ($34,279,877 on a jurisdictional basis) as presented in FPL Witness Scroggs's testimony and provided on SDS-8, Schedule AE-6. FPL's previous projected 2012 Preconstruction expenditures were $31,022,080 on a jurisdictional basis. The result is an underrecovery of Preconstruction revenue requirements of $3,257,796.

Q. What are FPL's 2012 actual/estimated TP 6 & 7 Preconstruction carrying charges compared to carrying charges previously projected and any resulting (over)/under recoveries of costs?

A. FPL's 2012 actual/estimated TP 6 & 7 Preconstruction carrying charges are $3,097,000. FPL's previous projected carrying charges were $5,620,298, resulting in an overrecovery of revenue requirements of $2,523,298. The calculations of the carrying charges can be found in Exhibit SDS-8, Schedules AE-2 and AE-3A.

Projected Revenue Requirements - 2013

Q. What revenue requirement amount is FPL requesting for its 2013 projected TP 6 & 7 Costs?

A. FPL is requesting recovery of $34,994,155 in revenue requirements related to its projected 2013 TP 6 & 7 Site Selection and Preconstruction costs. These revenue requirements consist of projected TP 6 & 7 Preconstruction expenditures of $29,211,385 ($28,686,236 on a jurisdictional basis) as presented in FPL Witness Scroggs's testimony and provided in Exhibit SDS-8, Schedule P-6 and projected carrying charges of $6,127,036 as shown in Exhibit SDS-8, Schedule P-2 and P-3A. Also included are projected TP 6 & 7 Site Selection carrying costs on the deferred tax asset of $180,883 as shown on Exhibit SDS-8.

Q. What is the total amount FPL is requesting to recover in its 2013 NCRC Capacity Cost Recovery factor for TP 6 & 7 Preconstruction costs?

A. FPL is requesting to include $20,356,123 of revenue requirements in 2013 for TP 6 & 7 Preconstruction costs.

This amount consists of the true-up of 2011 actual TP 6 & 7 Preconstruction costs and carrying costs of ($15,372,530), described in my March 1, 2012 testimony, the true-up of 2012 actual/estimated TP 6 & 7 Preconstruction costs and carrying costs of $734,498, the 2013 projected TP 6 & 7 Site Selection carrying costs of $180,883 and 2013 Preconstruction costs and carrying costs of $34,813,272, as shown on Exhibit WP-5.

For the reasons stated in FPL Witness Scroggs's testimony, FPL respectfully requests that the Commission approve the 2012 Actual/Estimated, and 2013 Projected Preconstruction costs and the carrying charges as reasonable, and approve the resulting revenue requirements described in my testimony for recovery in FPL's 2013 CCRC charge.

UPRATE PROJECT

Actual/Estimated Revenue Requirements - 2012

Q. What are FPL's 2012 actual/estimated Uprate Project expenditures compared to costs previously projected?

A. FPL's actual/estimated Uprate generation and transmission expenditures for the period January through December 2012 are $1,058,854,365, total company. As presented in FPL Witness Jones's testimony and shown on Exhibit TOJ-14, Schedule AE-6 deducts the portion of this total for which the

St. Lucie Unit 2 participants are responsible and then applies the retail jurisdictional factor to the remainder. This results in jurisdictional, net of participants Uprate generation and transmission expenditures of $1,017,306,408.

For actuals, further adjustments are made to present the expenditures on a cash basis (i.e., excluding accruals and pension and welfare benefit credits) for the calculation of carrying charges. These adjustments are necessary in order to comply with the Commission's current practice regarding AFUDC accruals. Since the estimated costs are on a cash basis, it is not necessary to project any non-cash accruals for the remainder of the year. After making these additional adjustments for calculating carrying charges, the actual/estimated 2012 jurisdictional, net of participants Uprate Project expenditures are $990,524,170, as shown on AE-6 in Exhibit TOJ-14. FPL's previous projected 2012 Uprate Project expenditures were $736,198,427 ($701,018,839, jurisdictional, net of participants).

Q. What is the revenue requirement amount that FPL is requesting to reflect the true-up of its 2012 actual/estimated Uprate Project costs?

A. FPL is requesting to true-up its 2012 revenue requirements for the Uprate Project by an additional $45,566,270.

Q. What are FPL's 2012 actual/estimated Uprate Project carrying charges, recoverable O&M, and base rate revenue requirements for plant placed

into service in 2012 compared to costs previously projected and any resulting (over)/under recoveries of costs?

A. FPL's 2012 actual/estimated Uprate Project carrying charges, recoverable O&M, and base rate revenue requirements for plant placed into service in 2012 are $198,482,692. FPL's previous projected revenue requirements were $152,916,422, resulting in an underrecovery of $45,566,270. The details of these jurisdictional costs (carrying charges, recoverable O&M and base rate revenue requirements) are summarized on Exhibit WP-5.

Q. What are the components of the true-up of $45,566,270 of 2012 revenue requirements?

A. The $45,566,270 consists of the true-up of carrying charges of $37,596,272, recoverable O&M including interest of $9,085,552 and base rate revenue requirements including carrying charges of ($1,115,554) as shown on Exhibit WP-5.

Q. Where can the calculation of FPL's Uprate Project 2012 actual/estimated carrying charges be found?

A. The calculation of the Uprate Project 2012 actual/estimated carrying charges of $104,860,725 can be found in Exhibit TOJ-14, Schedules AE-3 and AE-3A. FPL's previous projected 2012 Uprate carrying charges were $67,264,453 as filed in Docket No. 110009-EI. As a result of the actual/estimated true-up of 2012 carrying charges in this filing, there is an underrecovery of $37,596,272 in 2012.

Q. What are FPL's Uprate Project 2012 actual/estimated recoverable O&M costs and where can these costs be found?

A. FPL's Uprate Project 2012 actual/estimated recoverable O&M costs including interest are $15,000,523 ($14,546,749 jurisdictional, net of participants) and can be found in Exhibit TOJ-14, schedule AE-4. FPL previously projected 2012 recoverable O&M costs including interest of $5,626,844 ($5,461,197, jurisdictional, net of participants) as filed in Docket No. 110009-EI. As explained in schedule AE-4, over/under recoveries of recoverable O&M incur interest at the 30 day dealer commercial rate in the Wall Street Journal. As a result of the actual/estimated true-up of 2012 Uprate Project recoverable O&M including interest, there is an underrecovery of $9,085,552, jurisdictional, net of participants in 2012.

Q. What are the base rate revenue requirements for plant being placed into service in 2012 for the Uprate Project and where can the calculations be found?

A. The Uprate Project actual/estimated base rate revenue requirements including carrying charges for plant being placed into service in 2012 are $79,075,219 as shown in Exhibit WP-5. FPL previously projected base rate revenue requirements including carrying charges in the amount of $80,190,773.

The 2012 Actual/Estimated base rate revenue requirement calculations along with over/underrecoveries are shown on Appendices B and C in Exhibit TOJ-14. The 2012 Actual/Estimated base rate revenue requirements are based on

FPL's actual/estimated AE-3 transfers to plant in service of $1,637,991,957 ($1,524,087,530, jurisdictional, net of participants, net of adjustments), as shown in Exhibit TOJ-14, Appendix A. The 2012 projected base rate revenue requirements were based on transfers to plant in service filed in Docket No. 110009-EI of $1,268,800,397 ($1,187,022,441, jurisdictional, net of participants, net of adjustments). The plant expected to be placed into service in 2012 is discussed in FPL Witness Jones's testimony.

As described in Order No. PSC-08-0749-FOF-EI in Docket No. 080009-EI, FPL "shall be allowed to recover through the NCRC associated revenue requirements for a phase or portion of a system placed into commercial service during a projected recovery period. The revenue requirement shall be removed from the NCRC at the end of the period. Any difference in recoverable costs due to timing (projected versus actual placement in service) shall be reconciled through the true-up provision". Until the plant goes into service, FPL will continue to recover the carrying charges on the construction costs. Effective in the month each transfer to plant in-service is made, FPL will transfer the related costs from Construction Work in Progress (CWIP) to plant in-service and the carrying charges will cease. For the portion of the month the plant is in service and in subsequent months, inclusion of the 2012 base rate revenue requirements related to the plant going into service is included for recovery through the NCRC. Included in the base rate revenue requirement is any non-incremental labor related to the Uprate Project. FPL's

2012 actual/estimated transfers to plant in service, including non-incremental labor, is shown in Exhibit WP-6. An explanation of non-incremental labor was provided in my March 1, 2012 testimony in this docket.

Projected Revenue Requirements - 2013

Q. **What are FPL's Projected Uprate Project construction expenditures for the period January through December 2013?**

A. FPL's 2013 Projected Uprate generation and transmission construction expenditures are $163,996,072 (total company), as presented in FPL Witness Jones's testimony and provided on Exhibit TOJ-14, Schedule P-6. Schedule P-6 of Exhibit TOJ-14 deducts the portion of this total for which the St. Lucie Unit 2 participants are responsible and then applies the retail jurisdictional factor to the remainder. Since FPL's projections are on a cash basis, it is not necessary to project any non-cash accruals. After making the above adjustments, the jurisdictional, net of participants, 2013 projected Uprate Project construction expenditures are $161,047,828.

Q. **What are FPL's 2013 Projected Uprate Project carrying charges, recoverable O&M, and base rate revenue requirements for plant placed into service in 2013?**

A. FPL's 2013 projected Uprate Project revenue requirements are $85,212,207, consisting of carrying charges of $15,396,136, recoverable O&M including interest of $5,170,770 ($5,077,869 jurisdictional net of participants), and base rate revenue requirements of $64,738,202 for plant projected to be placed into service in 2013, as shown on Exhibit WP-5 and TOJ-14, P-4 for total company O&M.

The calculation of the Uprate Project 2013 projected carrying charges of $15,396,136 is shown on Exhibit TOJ-14, Schedules P-3 and P-3A and includes carrying charges on overrecoveries of base rate revenue requirements as noted in footnote (d) on Schedule P-3. The Uprate Project 2013 projected recoverable O&M including interest $5,170,770 ($5,077,869, jurisdictional, net of participants) is shown in Exhibit TOJ-14, Schedule P-4. As explained in Schedule P-4, over/under recoveries of recoverable O&M incur interest at the 30 day dealer commercial rate in the Wall Street Journal. The Uprate Project projected base rate revenue requirements for plant placed into service in 2013 are $64,738,202 as shown in Exhibit WP-5. The calculation of the base rate revenue requirements are reflected in Exhibit TOJ-14, Appendices A, B and C. As I explained previously, included in the base rate revenue requirement impact is any non-incremental labor related to the Uprate Project.

Q. What is FPL projecting to transfer to plant in-service for the Uprate Project in 2013?

A. In 2013, FPL's projected transfers to plant in service total $719,494,626 ($706,559,889, jurisdictional, net of participants) as shown on Exhibit TOJ-14, Appendix A. The plant projected to be placed into service is discussed in FPL Witness Jones's testimony.

Q. What is the amount FPL is requesting to recover through the Capacity Clause Recovery factor for the Uprate Project in 2013?

A. In 2013, FPL is requesting to recover for the Uprate Project $130,383,536 for carrying charges, O&M, and base rate revenue requirements. This amount consists of the true-up of 2011 actual Uprate Project revenue requirements of ($394,942) described in my March 1, 2012 testimony, the true-up of 2012 actual/estimated Uprate Project revenue requirements of $45,566,270, and the 2013 projected Uprate revenue requirements of $85,212,207.

For the reasons stated in FPL Witness Jones's testimony, FPL respectfully requests that the Commission approve FPL's 2012 Actual/Estimated and 2013 Projected Uprate expenditures and the resulting revenue requirements as reasonable, and approve the resulting revenue requirements described in my testimony for recovery in FPL's 2013 CCRC charge.

ACCOUNTING CONTROLS

Q. Please describe the accounting controls that provide you reasonable assurance that the costs included in the filing are correct.

A. FPL has a robust system of corporate accounting controls. The Company relies on its comprehensive corporate and overlapping business unit controls for recording and reporting transactions associated with any of its capital projects including the TP 6 & 7 Project and Uprate Project. Highlights of the Company's comprehensive and overlapping controls include:

- FPL's Accounting Polices and Procedures;
- Financial systems and related controls including FPL's general ledger and construction asset tracking system;
- FPL's annual budgeting and planning process;
- Reporting and monitoring of plan costs to actual costs incurred; and
- Business Unit specific controls and processes.

These accounting control are discussed in my March 1, 2012 testimony and are further discussed along with project controls in the testimonies of FPL Witnesses Scroggs and Jones.

Q. Are these controls documented, assessed and audited and/or tested on an ongoing basis?

A. Yes. The FPL corporate accounting policies and procedures are documented and published on the Company's internal website (Employee Web). Included on the Company's internal website are the corporate procedures regarding cash disbursements, accounts payable, contract administration, and financial closing schedules, which provide the business units guidance as to the processing and recording of transactions. The business units can then build their more specific procedures around these corporate procedures. FPL's internal audit department annually audits the TP 6 & 7 and Uprate Projects. The FPSC staff also is continuing its audits. Additionally, by virtue of the schedules themselves, a high level of transparency allows all parties to review and determine the prudence and reasonableness of our filing.

Q. How does FPL ensure only incremental payroll is charged to the projects?

A. The Company has issued specific guidelines for charging labor costs to the project work orders. These guidelines emphasize the need for particular care in charging only incremental labor to the project work orders included for nuclear cost recovery and ensure consistent application of the Company's capitalization policy. These guidelines describe the process for the exclusion of non-incremental labor from NCRC recovery while providing full capitalization of all appropriate labor costs through the implementation of separate project capital work orders that will be included in future base rate recoveries.

Q. Did anything change in the method incremental labor is established from 2011 to 2012?

A. No. The guidelines in effect for 2011 apply to 2012 since, as a result of FPL's rate case (Docket No. 080677-EI), the Company reset the basis upon which incremental employee labor is established in determining which employees are clause recoverable. Employees dedicated to the Project and charging 100% of their time to the NCRC Projects during 2010 were considered incremental for the entire year 2010 and as a result, incremental for 2012. Employees that charged a percentage of their time to capital in the NCRC in 2010 are designated incremental for that percentage of their labor costs in 2012.

SUMMARY

Q. What is the total revenue requirement FPL is requesting the Commission approve for the 2013 Capacity Cost Recovery Clause factor?

A. FPL is requesting the Commission approve recovery of $150,739,659 in revenue requirements through the 2013 Capacity Cost Recovery factor. This amount consists of a true-up of ($15,767,472) in revenue requirements as calculated in the 2011 T Schedules filed on March 1, 2012, a true-up of $46,300,768 in revenue requirements as calculated in the 2012 AE Schedules, and $120,206,363 in revenue requirements as calculated in the 2013 P Schedules.

FPL is also requesting the Commission determine that FPL's 2012 actual/estimated and 2013 projected costs and the resulting revenue requirements are reasonable as supported by my Exhibit WP-5.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF WINNIE POWERS

DOCKET NO. 120009-EI

SEPTEMBER 7, 2012

Q. Please state your name and business address.

My name is Winnie Powers, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

Q. Have you previously filed testimony in this docket?

A. Yes. This is a supplement to my previously-filed testimony.

Q. What is the purpose of this supplement to your testimony?

A. The purpose of my testimony is to explain my errata filed June 11, 2012.

Q. Are you sponsoring any supplemental exhibits to this testimony?

A. No.

Q. Please explain the corrections in your errata dated June 11, 2012.

A. First, FPL made corrections to implement the financial audit findings by Staff Witness Ms. Maitre. Second, FPL corrected an error to the return that was paid on the deferred tax liability after plant was placed into service. Third, a few computational and formulaic errors were corrected.

Q. Does this conclude your supplemental testimony?

A. Yes.

MR. ANDERSON: FPL will call as its next witness Mr. Terry Jones. We have some handouts which are exhibits from his testimony that he will be addressing, and you can see some of them back behind where he will appear as a witness.

CHAIRMAN BRISÉ: Thank you.

Just as a housekeeping note, we will be breaking for lunch at noon, so just keep that in mind. Not that -- we're not trying to say that we'll be done with Dr. Jones by noon. We're just suggesting that we will break at around that time.

MR. ANDERSON: I believe a handheld microphone is being made available also. Are you good on that down there? Good. Okay.

So, Mr. Jones, whenever you're set, just let us know. We'll be good.

Whereupon,

TERRY O. JONES

was called as a witness on behalf of Florida Power & Light Company, and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. ANDERSON:

Q Good morning, Mr. Jones.

A Good morning.

Q You've been sworn already this morning?
A Yes, I have.
Q Would you tell us your name and business address?
A Terry Jones, 700 Universe Boulevard, Juno Beach --
Q By whom are you employed and in what capacity?
A I'm employed by Florida Power & Light. I'm the vice president for the extended power uprate.
Q Have you prepared and caused to be filed 46 pages of prefiled direct testimony on March 1, 2012?
A That is correct.
Q You also prepared and caused to be filed 47 pages of prefiled direct testimony on April 27, 2012; is that right?
A That is correct.
Q You also filed three pages of prefiled supplemental testimony on August 1; is that right?
A That is correct.
Q You submitted errata on August 1 and September 7?
A That is correct.
Q Do you have any other changes or revisions to your prefiled direct?
A Yes. Consistent with my errata filed

September 7th and my April 27th testimony, page 8, line 2, the reference to fifty-two cents should be fifty-five cents. And on line 3, 24% should be 25%.

Q So if you were asked the same questions today contained in your prefiled direct and the supplemental testimony with the changes you've provided, would your answers be the same?

A Yes.

MR. ANDERSON: Chairman Brisé, FPL asks that the prefiled direct and supplemental testimony of Mr. Jones and errata dated August 1 and September 7 be inserted into the record as though read.

CHAIRMAN BRISÉ: Okay. We will enter Mr. Jones' direct testimony as well as supplemental testimony into the record as though read, including the errata.

BY MR. ANDERSON:

Q Mr. Jones, you have a number of exhibits?

A Yes.

Q TOJ-1 through TOJ-25, which have been premarked as Exhibits 51 through 75?

A That's correct.

Q Also TOJ-28 and 29, as corrected by the June 11 errata that you referred to?

A That's correct.

Q And those are, have been premarked as Exhibits 112 and 113.

MR. ANDERSON: Mr. Commissioner, we'd like to ask that the June 11 errata have an exhibit number.

CHAIRMAN BRISÉ: Sure. We, we are at 131.

MR. ANDERSON: Okay.

CHAIRMAN BRISÉ: This is June 11 errata.

(Exhibit 131 marked for identification.)

MR. ANDERSON: And those are the exhibits which at the end of his testimony we'll be offering into the record.

CHAIRMAN BRISÉ: Sure. Sure.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Power Plant	)	DOCKET NO. 120009-EI
Cost Recovery Clause	)	FILED: August 1, 2012

TESTIMONY OF TERRY O. JONES, MARCH 1, 2012

PAGE #	Line	ERRATA
35	7	Change "and this work caused the outage to be extended approximately 22 days" to "and this work took approximately 22 days to complete."

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 120009-EI

MARCH 1, 2012

Q. Please state your name and business address.

A. My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprate.

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

A. In my current role, I report directly to the Chief Nuclear Officer. I am responsible for the management and execution of the Extended Power Uprate ("EPU" or "Uprate") Project.

Q. Please describe your educational background and professional experience.

A. I was appointed Vice President, Nuclear Power Uprate on August 1, 2009. In my current position I provide executive leadership, governance, and oversight to ensure the safe and reliable implementation of the EPU Projects for the four FPL nuclear units.

I joined FPL in 1987 in the Nuclear Operations Department at Turkey Point. Since then, my positions at FPL have included Vice President, Operations, Midwest Region; Vice President, Nuclear Plant Support; Vice President, Special Projects; Vice President, Turkey Point Nuclear Power Plant; Plant General Manager; Maintenance Manager; Operations Manager and Operations Supervisor. Prior to my employment at FPL, I worked for the Tennessee Valley Authority at the Browns Ferry Nuclear Plant and served in the US Nuclear Navy. I hold a Bachelors of Science degree and an MBA from the University of Miami.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring or co-sponsoring the following exhibits which are incorporated herein by reference:

- Exhibit TOJ-1, T-Schedules, 2011 EPU Construction Costs, containing schedules T-1 through T-7B. Exhibit TOJ-1 contains a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and myself.
- Exhibit TOJ-2, EPU Workforce, Investment, and Cost Recovery Summary
- Exhibit TOJ-3, Extended Power Uprate Project Instructions (EPPI) Index as of December 31, 2011
- Exhibit TOJ-4, Extended Power Uprate Project Reports 2011
- Exhibit TOJ-5, St. Lucie Unit 2 Main Transformer
- Exhibit TOJ-6, St. Lucie Unit 2 Turbine Rotor
- Composite Exhibit TOJ-7, St. Lucie Plant Pictures
- Composite Exhibit TOJ-8, Turkey Point Plant Pictures

- Exhibit TOJ-9, Extended Power Uprate Work Activities List as of December 31, 2011
- Exhibit TOJ-10, Equipment Placed In Service in 2011
- Exhibit TOJ-11 Plant Change Modification (PCM) Status as of December 31, 2011
- Exhibit TOJ-12, Extended Power Uprate Project Schedule as of December 31, 2011
- Exhibit TOJ-13, Summary of 2011 Extended Power Uprate Construction Costs

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain the EPU project; key management decisions and project activities that occurred in 2011; FPL's 2011 Uprate construction expenditures; and the procedures, processes, and controls that ensure that those expenditures are reasonable and the result of prudent decision making. My testimony also explains the careful engineering-based process employed by FPL to ensure that it is including in its Nuclear Cost Recovery request only nuclear Uprate costs that are "separate and apart" from other costs, such as those for base rate nuclear operations and maintenance or capital projects that are unrelated to the nuclear Uprate Project.

Q. Please summarize your testimony.

A. The EPU project is a complex undertaking to safely increase the capacity of FPL's four existing nuclear units – St. Lucie (PSL) Units 1 & 2 and Turkey Point (PTN) Units 3 & 4 – which will provide significant and quantifiable benefits for customers without expanding the footprint of FPL's existing nuclear power plant sites. Upon completion in 2013, FPL estimates that approximately 490 megawatts electric power (MWe) will be provided by the EPU project for FPL's customers, and that customers will realize significant fuel cost savings as a result. This represents a 40 MWe increase over the previous assumption that the EPU project could be expected to provide approximately 450 MWe for the benefit of FPL's customers, and a 91 MWe increase over the conservative initial projection of 399 MWe. Most of this increased output will begin serving customers in 2012.

FPL's substantial investment in the EPU project – only a small portion of which is recovered through the Nuclear Cost Recovery (NCR) clause – is employing over a thousand workers and achieving complex nuclear fleet improvements that will serve FPL's customers for decades. Through 2011, as shown on Exhibit TOJ-2, for the EPU project, FPL has:

- invested approximately $1.3 billion; and
- employed over 3,300 EPU workers at its nuclear power plant sites.

This investment in Florida's energy infrastructure and economy has been made possible by the legislature's policy to support investment in nuclear projects, set forth in the NCR statute, and the Commission's careful implementation of that policy through the NCR Rule and this annual hearing process.

Through 2011, FPL has invested a total of $1.3 billion in the EPU project and has collected $149 million through the NCR Clause. Consistent with the NCR Rule, FPL recovers (i) carrying charges on the capital investment, (ii) incremental Operations & Maintenance (O&M) expenses, and (iii) partial-year revenue requirements for systems placed in service for the EPU project – not its construction costs. Construction costs will be recovered through base rates over the life of the uprated units or systems placed in service. While the NCR amount is modest in comparison to FPL's total investment, the annual nuclear cost recovery process and continued support for investment in nuclear projects is crucial to the successful completion of the EPU project.

The project team substantially completed the licensing engineering in 2011 and continued responding to Nuclear Regulatory Commission (NRC) Requests for Additional Information (RAI) associated with the EPU License Amendment Request (LAR) submittals made in 2010 and 2011, and is in the process of completing design modification engineering, procuring equipment and materials, and implementing plant modifications necessary to support the uprate conditions for each of the nuclear units. This process is supported by robust and overlapping project schedule and cost controls, along with rigorous risk management. Additionally, the EPU team manages the Uprate work in a manner that ensures that only the costs necessary for the Uprates are expended and included in the Nuclear Cost Recovery process.

Progress in 2011 included the following:

- the successful completion of two EPU outages, one at Turkey Point Unit 4 and the other at St. Lucie Unit 2 resulting in increased electrical output from St. Lucie Unit 2 of 31 MWe that is already benefitting FPL's customers;
- the continuance of the LAR engineering evaluations along with the submittal of the EPU LAR for St. Lucie Unit 2 and submittal of the Core Operating Limits Report (COLR) LAR for Turkey Point;

- the acceptance for review of the three EPU LARs by the NRC – the St. Lucie Unit 1 EPU LAR, the St. Lucie Unit 2 EPU LAR, and the Turkey Point Units 3 & 4 EPU LAR – and the COLR LAR for Turkey Point;
- NRC approval of the Turkey Point Alternative Source Term (AST) LAR and Spent Fuel Criticality LAR;
- continued work towards completing the engineering design of approximately 220 plant design modification packages;
- continued intensive management of major vendors including the Engineering, Procurement and Construction (EPC) vendor Bechtel;
- establishment of a target price for the St. Lucie scope of work and discussions related to a possible target price for the Turkey Point scope of work;
- extensive modification engineering for the 2011 St. Lucie and Turkey Point EPU outages and continued management of the EPC vendor and other major vendors;
- continued scheduling and planning for implementation of the modifications in proper sequence; and
- continued forward-looking project management resulting in adjustments to outage dates and durations and project plans.

FPL prudently incurred approximately $681 million of EPU costs during 2011, as compared to the May 2, 2011 actual/estimated amount of approximately $610 million. The 2011 variance is primarily attributable to additional NRC-required licensing engineering and NRC resource constraints which resulted in unanticipated project delays, increased work scope for design modification engineering, and increased modification implementation time due to increased work scope and constructability complexities.

Q. Please describe how the remainder of your testimony is organized.

A. My testimony includes the following sections:

- 2011 Project Summary
- Project Management Internal Controls
- Procurement Processes and Controls
- Internal/External Audits and Reviews
- "Separate and Apart" Considerations
- 2011 Project Activities
- 2011 Construction Costs

2011 PROJECT SUMMARY

Q. What is the EPU Project?

A. The EPU project will increase FPL's nuclear generating capacity from its four existing nuclear units by fitting the units with higher capacity and more efficient turbines and other necessary equipment to accommodate increased steam flow that will result from increased reactor power. This involves the modification or outright replacement of a large number of components and support structures within FPL's operating nuclear power plants. Each modification/replacement is considered a project in and of itself which is then integrated into the planned implementation work scope. In the case of some major modifications, some permanent plant equipment will have to be removed in order to have the necessary access to perform Uprate modifications and then reinstalled as part of the construction process.

Because the project will modify FPL's operating nuclear plants, it is a much different construction project than constructing a new combined cycle generating unit at a greenfield site or a modernization project in which the existing generating unit is removed from the site before the new generating unit is installed. In addition to being much more technically difficult, there are far greater engineering, construction, and cost uncertainties since FPL is performing the EPU project on existing operating nuclear units. FPL plans to perform almost all of the modifications during the units' pre-planned refueling outages. Performing the Uprate work during the refueling outages minimizes the amount of time that these low fuel-cost generators are off line.

FPL expects the EPU project to produce approximately 490 net MWe for FPL's customers. This reflects the turbine vendor's estimate of the turbine generator's performance less the co-owners' share of PSL Unit 2 and increased plant electrical requirements. During 2011, plant heat balances were recalculated and estimates for house loads were reduced, which resulted in an increase from FPL's previous 450 MWe output estimates. These recalculations support FPL's current estimate that a total of about 490 MWe will be produced by the uprated units for FPL's customers.

Q. How will customers benefit from the EPU project?

A. Among other benefits, this increase in nuclear power output will: (i) enhance system reliability and integrity by diversifying FPL's fuel mix; (ii) provide energy and baseload capacity to FPL's customers with zero greenhouse gas emissions; (iii) provide significant fuel cost and environmental compliance cost savings; and (iv) due to the increased capacity at the Turkey Point site, will help maintain balance between generation and load in Southeastern Florida. Some of these benefits have been realized in 2011, when the replacement of a low pressure turbine generator at St. Lucie Unit 2 with a more efficient low pressure turbine generator resulted in increased electrical power for FPL's customers of approximately 31 MWe. Quantification of these types of benefits will be provided along with an updated project feasibility analysis in FPL's May 2012 testimony.

Q. Please describe the general approach to the EPU project.

A. In 2007, FPL prepared an initial conceptual engineering study for performing an EPU at St. Lucie and Turkey Point which included a conceptual cost estimate based on a preliminary scope. This study provided the basis for FPL's request for a determination of need. In addition, in 2008, Shaw Stone & Webster (Shaw) performed a scoping study for FPL.

The EPU project is currently being implemented in four overlapping phases:

1. In the Engineering Analysis Phase, the analyses that support the LAR are performed. During this phase, the major modifications required to implement the EPU are identified and confirmed, the LARs are prepared and submitted to the NRC for acceptance and approval, the NRC approves a license amendment for

each plant (or unit, as applicable), and the conceptual scope is better defined. In 2011 this phase of the project was essentially completed with the acceptance for review by the NRC of three EPU LARs, St. Lucie Unit 1, St. Lucie Unit 2, and the Turkey Point Units 3&4. The remaining effort for this phase is to respond to NRC RAIs, confirm any plant design modification changes that may be required as a result of the NRC's review, and obtain NRC approval of the LARs. In 2011, the NRC approved the Turkey Point AST LAR, which was submitted and accepted for review by the NRC in June of 2009, and the Turkey Point Spent Fuel Criticality LAR which was submitted and accepted for review by the NRC in August 2010.

2. In the Long Lead Equipment Procurement Phase, the major long lead equipment is procured. During this phase, purchase specifications were developed, vendor quotes were requested, vendor proposals were received and evaluated, contracts were awarded, and the cost of long lead equipment was better defined. The vast majority of this phase was completed in 2011. Delivery dates and payment schedules for this equipment were established around the planned outages when the equipment would be installed into each facility.

3. In the Engineering Design Modification Phase, the detailed modification packages are prepared. During this phase, calculations are prepared, construction drawings are issued, some equipment and materials are procured, general installation instructions are provided, and high level testing requirements are identified. These activities provide the basis for preparing detailed estimates of the implementation costs. Approximately 220 design modification packages will be

prepared, ranging from small modifications, such as changing a valve size, to major modifications, such as removing a major piece of large heavy equipment and replacing it with new larger and heavier equipment needed to support the EPU conditions of increased energy flow. Additionally, some design modification packages are necessary to meet NRC requirements. The engineering design modification packages needed for the three outages in 2011 were completed to support the preparation of the modification packages work scope along with progressing with those needed for the three 2012 outages.

4. The Implementation Phase consists of two major parts. The first part is planning and scheduling. Planning is the process to convert the design modification packages into detailed work orders for implementation. During this part of the implementation, revisions to the design may be warranted based on constructability. Scheduling is the process that takes the detailed work orders and converts them into a detailed integrated implementation schedule which ultimately is the point at which the final outage durations are determined. The second part of the implementation phase is actual execution of the physical work in the plant including extensive testing and systematic turnover to operations. This phase of the project is reaching its peak and will continue through completion of the EPU project. Following the startup of each unit and operation at EPU conditions, extensive baseline testing will be performed to ensure continued reliable operation. Once the final outage at each unit is complete and the unit is operating at EPU conditions the project close out will begin. Project close out completes the implementation phase of the project.

Q. Are some activities being performed in parallel?

A. Yes. FPL is performing many activities in parallel in order to bring the benefits of additional nuclear power generation to its customers as soon as practical. The current project schedule is approximately 5 years long and scheduled to end in 2013. On the other hand, if FPL had worked through each phase of the project in sequence (i.e., by performing all LAR analyses for all units first, then procuring all equipment for all units next, etc.) the EPU project would have taken many more years.

Q. When will customers begin receiving the additional output from FPL's nuclear units?

A. Customers began benefitting from an additional 31 MWe from St. Lucie Unit 2 in 2011, by virtue of the installation of a more efficient low pressure turbine generator rotor. Most of the additional output from the EPU project – about 336 MWe – is expected to come on line by the end of 2012. The remaining approximately 123 MWe will be realized in 2013 after the final outage.

Q. Does FPL include industry best practices into the work being performed for the EPU project?

A. Yes. For example, the FPL project team members participate in nuclear industry working groups organized by the Institute of Nuclear Plant Operations and the Nuclear Energy Institute and benefit from lessons learned at other plants. This is supplemented with direct engagement with our industry peers through benchmarking trips to other nuclear sites which have performed similar scopes of work to incorporate best practices. These sources help ensure project decisions are supported by the best information currently available.

Q. Will project scope continue to evolve as the project moves forward?

A. Yes. Even after completing the engineering analyses required for the LAR submittal, the potential exists that additional scope will be required by the NRC. After the NRC approves the LARs, the project scope will be further defined and, commensurate with engineering design modification progress, the cost estimate range will be further refined. During the engineering design modification phase, additional scope is identified as specific designs evolve. During the detailed constructability reviews additional required work scope may be identified including additional construction support activities such as rigging or interference removal. Once the modification packages are final and the work order planning is complete, the implementation scope will be fully defined allowing the final refinement of the detailed implementation cost estimates and outage schedule durations. These activities lead to increased cost certainty with the achievement of each milestone.

Q. Please provide a brief overview of 2011 activities and costs.

A. Through 2011, the EPU project was nearing completion of the Engineering Analysis and the Long Lead Procurement Phases, and progressing with the Engineering Design Modification and Implementation Phases in support of each outage. Several of the key activities completed in 2011 include:

- the successful completion of two EPU outages, one at Turkey Point Unit 4 and the other at St. Lucie Unit 2 resulting in increased electrical output from St. Lucie Unit 2 of 31 MWe that is already benefitting FPL's customers;

- the continuance of the LAR engineering evaluations along with the submittal of the EPU LAR for St. Lucie Unit 2 and submittal of the COLR LAR for Turkey Point;
- the acceptance for review of the three EPU LARs by the NRC – the St. Lucie Unit 1 EPU LAR, the St. Lucie Unit 2 EPU LAR, and the Turkey Point Units 3 & 4 EPU LAR – and the COLR LAR for Turkey Point;
- NRC approval of the Turkey Point AST LAR and Spent Fuel Criticality LAR;
- continued work towards completing the engineering design of approximately 220 plant design modification packages;
- continued intensive management of major vendors including the EPC vendor Bechtel;
- establishment of a target price for the St. Lucie scope of work and discussions related to a possible target price for the Turkey Point scope of work;
- extensive modification engineering for the 2011 St. Lucie and Turkey Point EPU outages and continued management of the EPC vendor and other major vendors;
- continued scheduling and planning for implementation of the modifications in proper sequence; and
- continued forward-looking project management resulting in adjustments to outage dates and durations and project plans.

In total, FPL spent approximately $681 million in 2011 (as compared to the $610 million that was previously estimated) to carry out these key activities and proceed with the execution of the Uprate Project, all of which work was subject to the robust project planning, management, and cost control processes that FPL has in place and strives to continuously improve.

FPL's EPU activities and expenditures, including cost variances by cost category, and its internal processes and controls, are described in more detail below.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. Please describe the EPU project management organization during 2011.

A. As described below, FPL has robust project planning, management, and execution processes in place. These efforts are spearheaded by personnel with significant experience in project management within the nuclear industry. Additionally, the EPU project uses guidelines and Project Instructions to assist project personnel in the performance of their assigned duties. Exhibit TOJ-3, Extended Power Uprate Project Instructions (EPPI) Index as of December 31, 2011 is provided to illustrate the types of instructions that were used.

FPL has a dedicated Nuclear Power Uprate team within the Nuclear fleet that is responsible for monitoring and managing the Uprate Project, schedule, and costs. In addition to centralized project oversight, there is an EPU Site Director and an EPU organization at each site responsible for the efficient and effective engineering and implementation of the EPU project modifications. This decentralized management structure is appropriate as the EPU Project carries out the implementation phase at each of the sites to better integrate EPU activities with plant operating and outage activities.

There is also a separate Nuclear Business Operations (NBO) group that provides accounting and regulatory oversight for the EPU Project. This organization is independent of the EPU Project team and reports to the Vice President Nuclear Finance.

Q. Please describe the role of the NBO group in more detail.

A. As described in project instruction EPPI-150, EPU Project – Nuclear Business Ops Interface, NBO provides accounting and regulatory oversight for the EPU Project. It is independent of the EPU Project team and reports to the Vice President Nuclear Finance. NBO's primary responsibilities include:

- Review, approval, and recording of monthly accruals prepared by the Site Cost Engineers;
- Conducting monthly detail transaction reviews to ensure that labor costs recorded to the EPU Project are only for those FPL personnel authorized to charge time to the EPU Project;
- Conducting on-going analysis to evaluate project costs to ensure they are "separate and apart";
- Creating monthly variance reports that include cost figures used in the EPU Monthly Operating Performance Report;

- Performing analyses of the costs being incurred by the project to ensure that those costs are appropriately allocated to the correct Capital Expenditure Requisitions established for each nuclear unit's outages;
- Assisting in the classification of Property Retirement Units;
- Setting up and maintaining the EPU Project account coding structure;
- Providing accounting guidance and training to the EPU Team;
- Working closely with FPL's Accounting and Regulatory Accounting Departments to determine which costs related to the EPU Project are capital and which are O&M;
- Managing internal and external financial audit requests and ensuring that findings and recommendations are dispositioned, as appropriate; and
- Providing oversight and guidance to the EPU Project Team in developing and maintaining accounting-related project instructions to ensure compliance with corporate policies and procedures, and Sarbanes Oxley processes.

Q. What other schedule and cost monitoring controls were in place during 2011?

A. FPL utilizes a variety of mutually reinforcing schedule and cost controls and draws upon the expertise provided by employees within the project team, employees within the separate NBO group, and senior Nuclear management. Within the organization of the Vice President, Nuclear Power Uprate is a Controls Group. The Controls Director provides functional leadership, governance, and oversight. Each site has a dedicated EPU Project Controls group lead by a Project Controls Supervisor. The site Project Controls group provides cost and schedule analysis and associated performance indicators on a routine and forward-looking basis thus allowing Project Management to make informed decisions. Exhibit TOJ-4, Extended Power Uprate Project Reports

2011, lists many of the reports that are a direct result of the information the Controls group provides, analyzes and produces.

FPL's efforts to meet the desired completion date of each uprate is tracked through the use of Primavera P-6 scheduling software, enabling FPL to track the schedule daily and update the schedule weekly. This allows Project Management to monitor and report schedule status on a periodic basis. Updates to the schedule and scope of the project are made as such changes are approved by management. FPL's use of this scheduling software system allows management to examine the project status at any time as well as request the development and generation of specialized reports to facilitate informed decision making. When FPL identifies a scheduled milestone date that may have a high probability of missing its schedule date, a mitigation plan is prepared, reviewed, approved, and implemented with increased management attention to restore the scheduled milestone date or mitigate any impact of missing the scheduled date.

As part of the site Project Controls group, there are several highly experienced Cost Engineers assigned to monitor, analyze, and report project costs associated with the Uprate Project. Governed by well established procedures and work instructions, the Cost Engineer receives contractor invoices and forwards them to technical representatives to ensure the scope of work has been completed and the deliverables have been accepted. For fixed-price contracts, the Cost Engineer matches the invoice amount to the correct amount and the deliverable work received from the subject matter expert, which is then sent to the appropriate personnel for approval and payment. The Cost Engineer also prepares accruals and reviews variance reports monthly for each of the sites, to monitor and document expenditures and commitments to the approved budget. The Project Controls group operates in a transparent manner and its accountability is clear in providing sound analysis based on all available cost and schedule information at their disposal.

Q. What periodic reviews were conducted in 2011 to ensure that the project and key decisions were appropriately analyzed, reviewed and approved at the appropriate management levels?

A. Regularly scheduled meetings are held to help effectively manage the Uprate Project and communicate the performance of the project in terms of quality, schedule and costs. These include the following:

- Daily meetings to mutually share lessons learned information from each of the projects and to coordinate project activities;
- Weekly project management, project controls, and risk meetings to review the status of the schedules and project costs, and to identify areas needing attention;
- Biweekly meetings with the Chief Nuclear Officer; Vice President, Power Uprate; Implementation Owner South; and other project leaders to review project progress and work through any identified risks to schedules or costs;
- Routine, usually quarterly, FPL Executive Steering Committee meetings where Project Management presents the status of the project. Strategy discussions take place to help improve management of risk areas;

- Monthly Project Meetings involving FPL and individual major vendors during which the project schedules and challenges are discussed; and
- Quarterly Project Meetings involving FPL and its major vendors during which strategy discussions take place to help improve management of risk areas.

The EPU Project also produces several reports. Exhibit TOJ-4, Extended Power Uprate Project Reports, is a listing of reports generated by the project during 2011 with a brief description, the periodicity, and the intended audience of each report. Generally, the project reports provide a status of the project, scope changes, schedule and cost adherence/variance, safety, quality, risks, risk mitigation, and a path forward as appropriate. The information provided by these reports assists in the overall management of the EPU Project.

Finally, the project is annually reviewed to assess its continued economic feasibility. This analysis is conducted in a similar manner to the analysis that supported the affirmative need determination by the Commission, but it is updated to reflect engineering progress and what is currently known regarding the scope, cost, schedule,and predicted output of the project, and the cost and viability of alternative generation technologies. The analyses submitted by FPL Witness Sim in 2011 demonstrated that the EPU project continued to present a significant economic advantage in all fuel and environmental compliance cost scenarios. An updated feasibility analysis will be provided in the May 2012 NCR filing.

Q. Please describe the risk management process for the EPU project.

A. FPL's risk management process is governed by project instructions EPPI-340 and EPPI-345. FPL's risk management process is used to identify and manage potential risks associated with the uprates. A Project Risk Committee, consisting of site project directors and subject matter experts reviews and evaluates initial cost and schedule projections and any potential significant variances. This committee enables senior managers to critically assess and discuss risks faced by the EPU projects from different departmental perspectives. The committee also ensures that actions are taken to mitigate or eliminate identified risks. When an identified risk is evaluated as high, a risk mitigation action plan is prepared, approved, and executed. The high risk item is monitored through this process until it is reduced or eliminated. Additionally, an EPU Project Risk Management report is presented at meetings with senior management, identifying potential risks by site, unit, priority, probability, cost impact, and the unit or persons responsible for mitigating or eliminating the risk. These steps ensure continuous, vigilant identification of and response to potential project risks that could pose an adverse impact on cost or schedule performance of the project.

Q. Please describe the risk management process as it applies to Operational risk.

A. EPU Project work will be performed during normal plant operations and during planned refueling outages that are extended in duration in order to permit uprate work to be performed. The amount of work that can be safely performed during these plant conditions is dependent upon the minimum required systems or components needed to support the plant operating condition. Extreme care in the planning, scheduling, and execution of the work activities is required to ensure the plant is operated in accordance with applicable NRC regulatory and plant technical specification requirements. This requires proper sequencing of work activities that can be safely performed during normal plant operations or those that must be performed during planned refueling outages, including work activities that can be safely performed in parallel and those that must be performed in series. This operational risk management accomplishes two major objectives: first is to ensure the equipment is in a state that makes it safe for workers to perform the work, and secondly that the plant systems and components are properly maintained to ensure public safety. This operational risk management through the careful planning, scheduling, and execution of work activities adds to the complexity of the implementation phase of the EPU project.

PROCUREMENT PROCESSES AND CONTROLS

Q. Please describe the contractor selection and contractor management procedures that applied to the EPU projects in 2011.

A. The contractor selection procedures applicable to the Uprate Project are found in General Operating Procedure 705, Purchasing Goods and Services-Policy and Definitions and its series of procurement procedures and Nuclear Fleet Guideline BO-AA-102-1008, Procurement Control. As explained in those procedures, the standard approach for the procurement of materials or services with a value in excess of $25,000 is to use competitive bidding. However, the use of single source, sole source, and Original Equipment Manufacturer providers is also necessary in certain situations. FPL's policies require proper documentation of justifications and senior-level management approval of single or sole source procurements.

FPL has maintained its focus on the process of documenting and approving single and sole source procurements, to ensure compliance with BO-AA-102-1008 and to facilitate review by third parties who are not directly involved in the nuclear procurement process. Training is provided to personnel responsible for having Single and Sole Source Justifications (SSJs) prepared, the SSJ expectations are included in appropriate project instructions, and all new applicable personnel assigned to the EPU Project are required to review and understand the SSJ expectations.

With respect to vendor management, the EPU Project Directors at each site assure vendor oversight is provided by the experienced Project Managers, the Site Technical Representative, and Contract Coordinators. Together, these representatives provide management direction and coordinate vendor activity reviews while the vendors are on site. The Contract Coordinators verifies that the vendor has met all obligations and determines whether any outstanding deliverable issues exist using a Contract Compliance Matrix. In addition to assisting with the development and administration of contracts, Nuclear Sourcing and Integrated Supply Chain groups complete updates as necessary to a Project Contract Log and report the status of contracts to Project Management. EPU management also holds meetings with vendors as previously mentioned.

Q. What is FPL's approach to contracting for the EPU project?

A. FPL structures its contracts and purchase orders to include specific scope, deliverables, completion dates, terms of payment, commercial terms and conditions, reports from the vendor, and work quality specifications. Project Management has several types of contracts available depending on how well the scope of work and the risk associated with the work scope can be defined. Fixed price or lump sum contracts are used where practical. An example would be where project work scope is well-defined and risk is limited. Project Management will use a time and material contract where project work scope is not well-defined and where there is greater risk to completing the work scope. These and other contract provisions help ensure the contractors perform the right work at the right time for the right price, which ultimately benefits FPL's customers.

INTERNAL/EXTERNAL AUDITS AND REVIEWS

Q. Are FPL's financial controls and management controls audited?

A. Yes. Several audits have been conducted to ensure compliance with applicable project controls.

Q. Does Internal Audit conduct an annual review to ensure the project controls are adequate and costs are reasonable?

A. Yes. FPL completed an audit of EPU contract personnel time charges at Turkey Point. Experis, formerly Jefferson Wells, is in the process of performing an audit of 2011 expenses on behalf of the FPL Internal Audit Department. Specifically, the Experis audit is focusing on whether costs charged to the project are actually for the EPU project and are recorded in accordance with FPSC Rule 25-6.0423 and included independent testing of expenses charged to the EPU project for the period January 1, 2011 to December 31, 2011. Additionally, Internal Audit is performing an audit of the EPU contract personnel gate time at both the St. Lucie and Turkey Point sites.

Q. What external audits or reviews have been conducted to ensure the project controls are adequate and costs are reasonable?

A. FPSC staff is conducting two audits related to 2011 – a financial audit and an internal controls audit. The 2011 FPSC staff financial and internal controls audits will be provided to the Commission when completed.

Additionally, FPL retained Concentric Energy Advisors, Inc. to conduct a review of the 2011 EPU Project management controls. The results of this review is presented through the testimony of Mr. John Reed, the Chief Executive Officer of Concentric Energy Advisors.

"SEPARATE AND APART" CONSIDERATIONS

Q. Would any of the EPU costs included in FPL's filing have been incurred if the FPL nuclear generating units were not being uprated?

A. No. The construction costs, associated carrying charges and recoverable O&M expenses for which FPL is requesting recovery through the NCRC process were caused only by activities necessary for the Uprate Project, and would not have otherwise been incurred. I note that, as explained in FPL Witness Powers' testimony and schedules, only carrying costs and recoverable O&M expenses are requested for recovery for the EPU Projects, consistent with the Commission's NCRC rule.

Q. Please explain the processes utilized by FPL to ensure that only those costs necessary for the implementation of the Uprates are included for NCRC purposes.

A. Consistent with project instruction EPPI-180, EPU Nuclear Cost Recovery, FPL conducted engineering analyses to identify major components that must be modified or replaced in order to enable the units to function safely and reliably in the uprated condition. However, as inspections, LAR engineering analyses, and design engineering modifications are performed, the need for additional modifications or replacements necessary for the Uprate is identified. Likewise, certain modifications previously identified as necessary to the Uprate Project have been determined not to be necessary for the Uprate and have been removed from the EPU Project scope. FPL's 2011 EPU activities, and their associated costs, were "separate and apart" as required by the Nuclear Cost Recovery process.

2011 PROJECT ACTIVITIES

Q. What key activities occurred in 2011 in execution of the EPU project?

A. Several key activities occurred in 2011, including:

- the successful completion of two EPU outages, one at Turkey Point Unit 4 and the other at St. Lucie Unit 2 resulting in increased electrical output from St. Lucie Unit 2 of 31 MWe that is already benefitting FPL's customers;

- the continuance of the LAR engineering evaluations along with the submittal of the EPU LAR for St. Lucie Unit 2 and submittal of the COLR LAR for Turkey Point;
- the acceptance for review of the three EPU LARs by the NRC – the St. Lucie Unit 1 EPU LAR, the St. Lucie Unit 2 EPU LAR, and the Turkey Point Units 3 & 4 EPU LAR – and the COLR LAR for Turkey Point;
- NRC approval of the Turkey Point AST LAR and Spent Fuel Criticality LAR;
- continued work towards completing the engineering design of approximately 220 plant design modification packages;
- continued intensive management of major vendors including the EPC vendor Bechtel;
- establishment of a target price for the St. Lucie scope of work and discussions related to a possible target price for the Turkey Point scope of work;
- extensive modification engineering for the 2011 St. Lucie and Turkey Point EPU outages and continued management of the EPC vendor and other major vendors;
- continued scheduling and planning for implementation of the modifications in proper sequence; and
- continued forward-looking project management resulting in adjustments to outage dates and durations and project plans.

LICENSING

Q. Please describe the license amendment preparation and submittal activities in 2011.

A. FPL submitted the COLR LAR for Turkey Point and the St. Lucie Unit 2 EPU LAR to the NRC in 2011. The COLR LAR was submitted on February 21, 2011 and the St. Lucie Unit 2 EPU LAR was submitted on February 25, 2011; accordingly, FPL's efforts in 2011 included the continuing engineering analyses in support of responding to NRC RAIs. Additionally, the NRC completed its review and approved the Turkey Point AST LAR on June 23, 2011 and approved the Turkey Point Spent Fuel Criticality LAR on October 31, 2011. FPL continued to respond to NRC requests for additional information in a timely manner. The NRC accepted the following LARs for review in 2011: St. Lucie Unit 1 EPU LAR on March 9, 2011; the Turkey Point EPU LAR on March 11, 2011; the Turkey Point COLR LAR on March 29, 2011; and the St. Lucie Unit 2 EPU LAR on June 23, 2011. The NRC review and approval time for each EPU LAR was originally estimated to be approximately 12 months following NRC acceptance for review; however, actual review and approval times have been significantly longer primarily due to NRC resource constraints.

Q. Do industry-wide developments affect the NRC's review of FPL's EPU LARs?

A. Yes. The earthquake and tsunami in Japan and the earthquake in Virginia, discussed further below, have adversely impacted NRC staff resources, and consequently, the extended timeline for the review of FPL's EPU LAR submittals resulted in significant cost and schedule impacts to the EPU Project that will carry over into 2012.

Additionally, there is a development related to Westinghouse fuel performance analyses. Westinghouse's fuel performance analyses support the licenses of a number of nuclear power plants in the U.S., and in December 2011, Westinghouse informed the NRC that a change to its fuel performance modeling related to Thermal Conductivity Degradation (TCD) would change the results of those analyses. Plants that rely on Westinghouse's fuel performance analyses will be required to assess the impact of the Westinghouse model changes on their nuclear fuel performance. Westinghouse's analyses underlie the fuel performance assumptions at Turkey Point Units 3 & 4 and at St. Lucie Unit 2.

On December 7, 2011 NRC staff asked FPL what the effect would be if similar modeling changes were made to the analyses used for the Turkey Point EPU LAR. FPL took prompt action to evaluate the impacts of the TCD issue on Turkey Point and submitted its evaluation to the NRC on December 31, 2011. FPL also proactively began assessing the impact on its St. Lucie Unit 2 EPU LAR. This is an open item that will be addressed by the NRC Staff and presented to the NRC's Advisory Committee on Reactor Safeguards. Further, it has resulted in additional LAR engineering activities and an adjustment to the anticipated Turkey Point LAR approval date.

PROJECT EXECUTION

Q. Please describe activities related to the Long Lead Procurement phase in 2011.

A. In 2011, FPL completed the majority of contracts for long lead equipment. Several long lead procurement items were received, inspected, and stored or prepared for installation at the St. Lucie and Turkey Point plants. These items include steam turbine rotors, generator rotors, moisture separator reheaters, feedwater heaters, and main feedwater pumps. FPL also conducted several quality assurance reviews at the equipment manufacturing or testing locations.

Q. Please discuss the on-line and outage plant modification work that was successfully completed in 2011.

A. St. Lucie Unit 2 and Turkey Point Unit 4 successfully completed their first EPU outages in 2011. The major outage activities at St. Lucie Unit 2 included main generator stator rewind, replacement of the generator rotor, replacement of the main transformer for the increased electrical output at EPU conditions (a picture of which is attached as Exhibit TOJ-5), and replacement of the low pressure turbine rotor (a picture of which is attached as Exhibit TOJ-6). In total, the work for the St. Lucie Unit 2 outage required the following:

- Augmented staff of approximately 920 people at its peak;
- Approximately 4,000 individually planned, scheduled, and monitored activities supporting approximately 235 work packages; and
- Approximately 728,000 man hours of work.

The major outage activities at Turkey Point Unit 4 included feedwater heater inspections, feedwater heater drain valve replacements, isophase bus duct replacement, main transformer cooler upgrades, partial replacement of feedwater heaters, and feedwater heater drains digital controls replacement. In total, the work for the Turkey Point Unit 4 outage required the following:

- Augmented staff of approximately 905 people at its peak;

- Approximately 2,900 individually planned, scheduled, and monitored activities supporting approximately 240 work packages; and
- Approximately 242,000 man hours of work.

FPL completed all planned EPU work during the St. Lucie Unit 2 and Turkey Point Unit 4 outages. FPL also initiated an outage at St. Lucie Unit 1 in November 2011 and began preparations for the 2012 Turkey Point Unit 3 outage in 2011. A compilation of pictures showing the St. Lucie and Turkey Point sites and the work being performed there is attached as Composite Exhibit TOJ-7 and Composite Exhibit TOJ-8, respectively.

Additionally, Turkey Point completed the upgrade of the Turbine Gantry Crane, and outage preparation work was completed at both plants while the units were on-line. Exhibit TOJ-9, Extended Power Uprate Project Work Activities as of December 31, 2011, is a listing by unit of the work activities accomplished on-line or during outages by EPU personnel in 2011. Exhibit TOJ-10 lists the equipment that was placed in service in 2011.

Q. Does the EPU project require increased staffing during non-outage periods as well?

A. Yes. In fact, the peak 2011 staffing level at Turkey Point of 1,604 EPU workers occurred outside of an outage. FPL regularly employs approximately 1,600 people at its two nuclear power plant sites. Over the course of the year, St. Lucie and Turkey

Point averaged an additional 750 workers and 890 workers for the EPU project, respectively.

Q. Please describe the outage preparation work that occurs during non-outage periods.

A. In addition to the modification engineering that must be performed for upcoming outages, extensive construction planning and logistical work is also performed. Such planning occurred in 2011 for the EPU outages scheduled for 2012.

Q. Please describe the management of the EPC vendor and the progress in modification engineering made in 2011.

A. The EPC vendor, Bechtel, continued its efforts to prepare the detailed modification packages in 2011. During this phase, calculations are prepared, construction drawings are issued, equipment and materials are procured, general installation instructions are provided, and high level testing requirements are identified. These activities provide the basis for preparing detailed estimates of the implementation costs.

Due to design evolution and complexity of construction, modification engineering and work package preparation continued to take longer than anticipated in 2011. Accordingly, FPL directed Bechtel to subcontract some of the engineering design scope, prioritized design and planning work based on implementation schedules to minimize any impacts to outages, developed and began implementing a plan to streamline the number of Bechtel work packages based on lessons learned, and instituted regular Daily Issue Meetings and senior executive oversight meetings to enhance FPL's management and oversight of Bechtel's work.

Q. What was the status of the Plant Change Modification packages as of December 31, 2011?

A. Exhibit TOJ-11, Plant Change Modification (PCM) Status as of December 31, 2011, is a chart that illustrates the number of identified engineering modifications as of December 31, 2011, the number of PCMs that have been initiated, and those that have reached 90% and final completion. As can be seen in this exhibit, there were 222 PCMs identified of which 143 were finalized and approved for issuance as of December 31, 2011. This exhibit demonstrates that the design engineering progress and additional identified work scope was substantial in 2011.

Q. Please describe FPL's efforts to manage vendor costs in 2011.

A. FPL continued to manage its major vendors, including its EPC vendor, to ensure the costs expended for the assigned scopes of work are reasonable and appropriate, including challenging estimates of future staffing requirements. For example, FPL conducted senior-level management meetings in Frederick, Maryland at Bechtel's headquarters to address then-current trends and metrics. FPL also awarded scopes of EPC work at St. Lucie to other vendors -- Day & Zimmermann NPS and Shaw-- both of which are experienced nuclear industry construction firms. These work assignments were made as part of FPL's continuing efforts to control costs. Additionally, FPL modified the EPC vendor contract to establish a "target price" in the PSL EPC contract. FPL also utilized High Bridge Associates, Inc. (High Bridge), to provide additional cost estimating expertise in 2011 to help manage the EPC costs.

Q. Please discuss the Estimate at Completion received from Bechtel in 2011 for Turkey Point work.

A. During 2011, as part of its project and cost management process, FPL asked Bechtel to provide a proposed target price to complete the Turkey Point EPU work. High Bridge was retained by Bechtel at FPL's request to perform craft implementation estimating services for this effort. Bechtel's Estimate at Completion (EAC) was then provided to FPL in November 2011.

Upon receipt of the Turkey Point EAC from Bechtel in November 2011, FPL immediately began performing the due diligence necessary to determine the appropriateness of the vendor's estimate. The estimate that FPL received reflected (i) design evolution, which means even if the total number of modifications is not changing, complexity of design is changing; (ii) increased implementation complexity; (iii) constructability issues that affect implementation productivity; and (iv) the resultant increase in field non-manual (i.e., design engineers, field engineers, and craft supervision), direct, and indirect labor to complete the project.

Q. What does FPL's due diligence include?

A. In 2011, FPL began performing a field non-manual staffing analysis and a review of the resource loaded schedule. Additionally, FPL sought information from Bechtel to explain its supervision/engineer-to-craft ratios and sought information for FPL's field non-manual analysis. FPL also engaged other major suppliers to provide alternative proposals for certain portions of Bechtel's scope of work. As of the end of 2011, FPL had not yet completed its due diligence nor begun senior management vetting of the estimate provided by Bechtel or its potential impact to project costs.

Q. Were there any unplanned schedule changes in 2011?

A. Yes. The EPU portion of the St. Lucie Unit 2 spring 2011 outage lasted longer than planned, due to an error by Siemens, the vendor who is performing the turbine generator upgrade work. It was determined that a small tool – an alignment pin – had been left inside the generator stator core by Siemens personnel. When the stator core was tested for performance, the alignment pin caused damage. As a result, the replacement of some of the stator core iron was required to repair the damage caused by the pin, and this work caused the outage to be extended approximately 22 days.

Q. Was FPL prudent in the hiring of Siemens?

A. Yes. Siemens is the Original Equipment Manufacturer and therefore owns all the intellectual property necessary to perform this scope of work. Siemens is highly specialized and has an excellent track record with similar work on other FPL projects. Moreover, Siemens has a robust system of practices and procedures that have resulted in successful projects over the years. FPL reviewed and benchmarked Siemens's performance at other locations to validate those practices and procedures, and performed diligent oversight of Siemens. FPL contracted with Siemens in 2008, which was subject to the Commission's prudence review of 2008 decisions and costs in 2009.

Q. Were FPL's 2011 activities related to the training and oversight of Siemens prudent?

A. Yes. FPL followed its procedures and processes to ensure proper training of Siemens and oversight of the work Siemens was hired to perform, including the work performed in 2011. FPL (and its industry peers) relies on the vast experience and excellent performance record of its vendors, adheres to its procedures for managing contractors, and takes corrective action when errors occur.

Q. Were there any other work stoppages caused by contractor personnel errors in 2011?

A. Yes. In December, consistent with industry good practices, Bechtel suspended work being performed by its electrical craft personnel at St. Lucie following an event in which craft personnel commenced work on an incorrect motor control center. Upon discovery, the supervisor immediately stopped the work. No injuries occurred and no equipment was damaged. The Bechtel electrical personnel were retrained in applicable processes, and returned to work after approximately two days. Other EPU work proceeded as planned, and there were no impacts on the overall outage duration.

Q. Was FPL prudent in the hiring, training, and oversight of Bechtel and the personnel involved?

A. Yes. The particular crew members had the proper qualifications and had previously underwent all required training, including training that directly applies to the type of situation that occurred. Further, the work package that was issued for this scope of work was correct – and included a specific instruction to the crew to ensure it was working on the correct component prior to initiating work. Nonetheless, these particular crew members acted inconsistent with the training and instructions that FPL and Bechtel had provided.

PROJECT PLANNING

Q. Did FPL continue to adjust the assignment of modifications to outages in 2011?

A. Yes. FPL adjusted a few modifications out of the St. Lucie Unit 2 spring 2011 outage into the summer 2012 outage, and out of the Turkey Point Unit 4 spring 2011 outage into the fall 2012 outage. Additionally, some transmission and substation work was moved to outages in 2012. These schedule revisions affected what FPL previously estimated would be placed in service in 2011.

Q. Were other project planning assumptions revised in 2011?

A. Yes. FPL determined in 2011 that the remaining outage dates and durations planned for 2011 and 2012 needed to be adjusted. The adjustments to the planned outage dates and durations were necessary in order to accommodate the refined work scope assigned for each outage, which scope reflects the modification previously made to outage assignments as well as increased project scope overall. FPL uses a variety of inputs to plan outages, including industry and fleet work experience from earlier outages where similar work activities were completed, refined engineering modifications scope and requirements, previous inspection results, and proper sequencing of the EPU modifications which must be coordinated with the NRC approval of the EPU LARs. As always, FPL must also factor into its planning and scheduling the safety of personnel performing work, e.g., securing system electrical, mechanical, and thermal energy sources, and ensuring that the unit that is in an outage is maintained safely and the other unit is operating safely in accordance with the operating license issued by the NRC. These outage schedule adjustments were previously discussed in my supplemental testimony filed in Docket No. 110009-EI on July 15, 2011.

Q. As of December 31, 2011, what was the overall EPU project schedule?

A. Exhibit TOJ-12, Extended Power Uprate Project Schedule as of December 31, 2011, illustrates the LAR, long lead material, engineering design, and implementation schedule for the EPU Project. Underlying this high–level schedule are tens of thousands of individually-scheduled activities. FPL's overall project schedule reflected the following:

- The LAR analyses were completed and submitted to the NRC. NRC approval of the St. Lucie Unit 1 LAR which is required for FPL to increase the power output at the completion of the second EPU outage for St. Lucie Unit 1, is challenged. Review and approval prior to completion of the second outage for the other units is expected.
- Due to delays in NRC licensing there were significant cost and schedule impacts that occurred and will continue in 2012. In order to minimize the financial and timing impacts, a new plan for a St. Lucie Unit 1 mid-cycle outage was developed. The outage duration is planned to be several days; long enough to change instrumentation set points and other minor modifications necessary for operation in the approved uprate conditions. The outage will also allow FPL to implement processes and procedures for operating the plant in the uprate condition.
- Long lead material items were scheduled to arrive on site prior to the outage during which the equipment will be installed.
- PCM engineering design for each of the identified modifications was scheduled to be approved for implementation prior to the unit outage when each modification will be implemented.
- Implementation of the EPU modifications was scheduled to be completed during the revised durations of the scheduled refueling outages for each of the units.

Q. Did FPL conduct a "feasibility analysis" of the EPU project in 2011?

A. Yes. FPL conducted a feasibility analysis in 2011 using the high end of FPL's 2011 non-binding cost estimate range, which demonstrated that the EPU project was projected to be solidly cost-effective for FPL's customers. Specifically, a resource plan that included the EPU project was projected to cost less than a resource plan that did not include the EPU project in seven out of seven scenarios of fuel cost forecasts and environmental compliance cost forecasts. A feasibility analysis using updated project and resource planning assumptions will be performed again in 2012 and filed with the Commission in May.

Q. Have the 2011 earthquake and tsunami in Japan or the 2011 earthquake in Virginia and resulting effects on the nuclear power plants there affected the EPU project?

A. Yes. These two natural events have adversely impacted the NRC staff resources and delayed the review and approval of the FPL EPU LARs. This had a significant impact to FPL's plans and contributed to the decision to delay the start of the St. Lucie Unit 1 outage and caused concern in regards to timing of the Turkey Point Unit 3 outage start scheduled for 2012. As a result, we had to expend considerably more FPL and contractor resources to engineer and plan for a mid-cycle implementation for St. Lucie Unit 1 and to modify our plan to accommodate the downstream impact on the other Florida Units. Despite our continuing efforts to manage the adverse impact, the two natural disasters and subsequent NRC response had significant cost and schedule impacts on the project that unfortunately will carry over into 2012.

2011 CONSTRUCTION COSTS

Q. What type of costs did FPL incur for the Uprate Project in 2011?

A. As indicated in Exhibit TOJ-1, Schedule T-6 and T-4, and summarized on Exhibit TOJ-13, Summary of 2011 Extended Power Uprate Construction Costs, Tables 1 through 9 (all reflecting the true-up of actual 2011 costs), costs were incurred in the following categories: License Application; Engineering and Design; Permitting; Project Management; Power Block Engineering, Procurement, Etc.; Non Power Block Engineering, Procurement, Etc.; and Recoverable O&M. These costs were the direct result of the prudent project management, decision making, and actions as described previously. Each category reflects some variance against what was estimated earlier in 2011, which is to be expected, particularly at this stage of the project. Exhibit TOJ-13, Summary of 2011 Extended Power Uprate Construction Costs contains summaries of the EPU expenditures in 2011 for each of the NFR schedule categories. Table 1 is a summary of each of the categories showing the actual expenditure amounts. The amounts shown in the exhibits are slightly different than the NFR schedules as footnoted on the exhibit.

Q. Please describe the costs incurred in the License Application category and the variance, if any, from the 2011 actual/estimated costs in this category.

A. Licensing Costs in 2011 consisted primarily of charges for contractor services rendered in supporting preparation, review and NRC approval of the EPU LARs. The primary contractors are Westinghouse, Areva and Shaw Stone & Webster. FPL incurred $39.8 million in this category in 2011, which was $20 million more than the actual/estimated amount. This variance was primarily attributable to the fact that costs to support NRC review and approval of the EPU LARs were significantly greater than expected. This included costs associated with the additional NRC-required engineering analyses and evaluations for the St. Lucie Unit 1 and 2 and Turkey Point EPU LARs.

Q. Please describe the costs incurred in the Engineering and Design category and the variance, if any, from the actual/estimated costs in this category.

A. Engineering and Design Costs consist primarily of costs for FPL personnel in the FPL engineering organizations at both sites and in the central organization. Some of these personnel provide management, oversight, and review, and preparation of the LAR activities, while others are oriented towards management, oversight, and review of the detail design activities being performed by the EPC contractor and other contractors. FPL incurred $23.3 million in this category in 2011, which is $3.1 million more than the actual/estimated amount. This was primarily attributable to scope growth and the costs required to manage the EPC contractor's engineering and implementation efforts for the PSL Unit 2 and PTN Unit 4 2011 outages.

Q. Please describe the costs incurred in the Permitting category and the variance, if any, from the actual/estimated costs in this category.

A. Permitting Costs reflect costs attributable to the State of Florida Site Certification Application for the St. Lucie and Turkey Point sites and the Substantial Revision Application for Increasing Discharge Temperature to the Florida Department of Environmental Protection (FDEP) for the St. Lucie Plant. These costs consist primarily of consulting services related to environmental work for site certification, compliance certification, FDEP application preparation, and FPL employee support.

FPL incurred $0.12 million in this category in 2011, which was $0.07 million more than the actual/estimated amount. This was primarily attributable to additional environmental work in the preparation of the Substantial Revision Application for Increasing Discharge Temperature to the FDEP for the St. Lucie Plant to ensure regulatory compliance.

Q. Please describe the costs incurred in the Project Management category and the variance, if any, from the actual/estimated costs in this category.

A. Project Management Costs relate to overall project oversight including project and construction management, and project controls and non-NRC regulatory compliance. These oversight activities are performed by personnel located at both sites, and by the EPU central organization and by non-EPU organizations such as NBO, New Nuclear Accounting and Regulatory Affairs. FPL incurred $35.1 million in this category in 2011 which was $1.3 million more than the actual/estimated amount. This was primarily attributable to an increase in FPL project and construction management oversight of the EPC vendor.

Q. Please describe the costs incurred in the Power Block Engineering, Procurement, Etc. category and the variance, if any, from the actual/estimated costs in this category.

A. The majority of the costs in this category reflect payments to the EPC vendor for engineering, procurement, and construction resources that supported the successful completion of the EPU outages at PSL Unit 2 and PTN Unit 4 in 2011 and the first month of the St. Lucie Unit 1 EPU outage, the continued engineering efforts to prepare for the 2011 and 2012 outages, payments to Siemens for turbines and generator rotors, and payments to Thermal Engineering International for feedwater heaters and moisture separator reheaters, main condensers, and increased capacity heat exchangers and pumps required to support the uprate conditions. This category also includes costs for High Bridge cost estimating services.

Additionally, this category includes the cost to complete the modifications to the St. Lucie Unit 2 main transformer, low pressure turbine rotor, and main generator rotor replacements, and the main generator stator rewind. It also includes the cost to complete the modifications to the Turkey Point Unit 4 isophase bus duct system, modifications to the turbine gantry crane, and main transformer cooler upgrades. The major pieces of salvageable equipment included the main generator stator windings, a main transformer, a low pressure turbine rotor and miscellaneous metal materials. The salvage value of this equipment will be credited back to the EPU project appropriately.

FPL incurred $540.8 million in this category in 2011, which is $41.8 million more than the actual/estimated amount. The primary contributors to this variance were increased work scope and longer than estimated installation durations which included planning, scheduling, and execution of the modifications. Further adjustments may be necessary as the LAR reviews, design engineering, and implementation planning activities are completed.

Q. Please describe the costs incurred in the Non-Power Block Engineering, Procurement, Etc. category and the variance, if any, from the actual/estimated costs in this category.

A. Non-Power Block Engineering Costs consist primarily of costs for facilities for engineering and project staff at site locations, incremental spent fuel cask costs and the simulator upgrades required to reflect the uprate conditions. FPL incurred $5.4 million in this category in 2011. This represents $0.7 million less than the actual/estimated amount. The variance is primarily attributable to costs for the simulator phase modifications being moved to later than originally planned.

Q. Please describe the costs incurred as EPU Recoverable O&M.

A. Recoverable O&M expenses in 2011 were $12.2 million. This represents a variance of $0.5 million less than the actual/estimated amount. Consistent with FPL's capitalization policy, the commodities that make up these expenditures consist of non-capitalizable computer hardware and software and office furniture and fixtures needed for new project-bound hires, all of which are segregated for EPU Project personnel use only, as well as incremental staff and augmented contract staff. Additionally, the Turkey Point Independent Spent Fuel Storage Installation cask loading campaignwas included in this category along with O&M EPU equipment inspections and modifications.

Q. Please describe the costs incurred in the Transmission category.

A. Transmission Costs were $24.4 million in 2011, which is $6.3 million more than the actual/estimated amount. The expenditures in the Transmission category include plant engineering, line engineering, substation engineering, and line construction. This variance is a result of the reclassification of the plant engineering for the procurement and installation of the new main transformer at St. Lucie Unit 2. Part of the substation construction was completed at Turkey Point. The remaining transmission and substation work is on schedule to support the EPU at each of the units. Work is being scheduled during unit outages and when system conditions permit.

Q. Were FPL's 2011 EPU expenditures prudently incurred?

A. Yes. FPL incurred costs of approximately $681 million in 2011. FPL's actual 2011 costs were greater than its previous estimate for the reasons described above, and are primarily attributable to additional NRC-required licensing engineering and NRC resource constraints, which resulted in unanticipated project delays, increased work scope for design modification engineering, and increased modification implementation time due to increased work scope and constructability complexities. Despite our continuing efforts to proactively manage the adverse impact from the two natural disasters and subsequent NRC response, we expect that the negative project cost impacts will, unfortunately, carry over into 2012.

All of FPL's expenditures were necessary so that the uprate work could be performed during the planned outages. Through well-qualified, experienced personnel's application of the robust internal schedule and cost controls, careful vendor oversight, and the ability to continuously adjust based on lessons learned and the project's evolving needs, FPL is confident that its EPU management decisions are well-founded and prudent. All costs incurred in 2011 were the product of such decisions, were prudently incurred, and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Power Plant Cost Recovery Clause	))	DOCKET NO. 120009-EI FILED: September 7, 2012

ERRATA SHEET

DIRECT TESTIMONY OF TERRY O. JONES, APRIL 27, 2012

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 120009-EI

April 27, 2012

Q. Please state your name and business address.

My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed with Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprates.

Q. What are the key things to know about the Extended Power Uprate project during 2012 and looking ahead to project completion in early 2013?

A. Here are the key things to know about the Extended Power Uprate (EPU or Uprate) project during 2012 and looking ahead to project completion in early 2013:

- It is a complex project in its final phase with huge benefits for FPL customers and for Florida for decades to come;
- The project provides the equivalent output of half a new nuclear plant in about half the time and at significantly less than the estimated cost per kW installed of a new nuclear plant – a strong value proposition;

- We now expect 490 megawatts electric (MWe) of output that will save customers over $114 million in fossil fuel costs in the first year;
- The project will contribute substantially to electric grid reliability by producing power near a major economic center for the state, southeast Florida.

Q. Will most of the project be done this year?

A. Yes. By year end, uprates of three of our four nuclear reactors will be complete. In particular:

- Five of eight EPU outages are complete, and we are midway through the sixth as of the date of this testimony; and
- The remaining EPU outages are the second (and final) at Turkey Point Unit 4 and the second (and final) at St. Lucie Unit 2.

Q. Is FPL expecting more power to be produced from the EPU project than was estimated last year?

A. Yes. FPL's EPU project is in full swing to provide 490 MWe of additional nuclear generation for FPL's customers during 2012 and early 2013, compared with last year's projection of 450 MWe. This is enough to meet the electricity needs of over 311,000 residential customers -- without natural gas or foreign oil usage or greenhouse gas emissions.

Q. In addition to the annual fuel cost savings you mentioned, how will the EPU project benefit customers?

A. The EPU project is expected to reduce fossil fuel usage by the equivalent of 6 million barrels of oil per year. FPL's CO2 emissions are projected to be lower by 32 million tons over the project's life. The EPU project makes more electricity close to where the most is used, enhancing electric grid stability and electric service reliability for FPL's customers. The EPU project adds to Florida's energy security because it does not depend on fuel delivery through Florida's only two natural gas pipelines.

Q. How will the EPU project deliver economic value for FPL's customers?

A. The EPU project provides customers with exceptional value. Even at this time of historically low natural gas and environmental cost forecasts -- which no one should bet on remaining permanently at these low levels -- our current economic snapshot shows the EPU project is expected to save customers billions of dollars in fuel costs over decades. If natural gas and environmental costs increase in future years, customers would save even more money due to the EPU project. Simply put, the EPU project provides a valuable hedge against future natural gas and environmental cost increases, as part of FPL's overall portfolio of resources used to provide economical and reliable electricity for customers.

Q. How does the EPU project compare with installing new nuclear generation?

A. As mentioned, the EPU project will provide about 9% more generation than was estimated last year. At 490 MWe, the project's generation is about half the output of a new nuclear plant, yet is delivered now from existing reactors, much faster than a new plant can be built, and at a lower cost. The EPU project will result in nuclear generation capacity installed at a significantly lower cost per kW now as compared to a new nuclear power plant ten years from now.

Q. What effort is needed to complete the project?

A. The EPU project and the effort that it requires are enormous. Fortunately, we have thousands of qualified people working hard to provide about 20 million total hours of work, including over 4 million man-hours of engineering alone, to complete the largest U.S. nuclear project undertaken since new plants were constructed decades ago.

Q. Is FPL on track to successfully complete the project?

A. Yes. FPL is rigorously and transparently managing the EPU project with the end clearly in sight. Three reactor uprates will be completed during 2012 and deliver 367 MWe of nuclear capacity. The fourth reactor uprate will be finished in early 2013, adding another 123 MWe – for the project total of 490 MWe of around-the-clock, zero emission, low fuel cost electric generation that will serve FPL customers and Florida for decades.

PROJECT OVERVIEW

Q. Please provide an overview of the EPU project.

A. FPL is continuing to work to deliver the substantial benefits of additional nuclear generating capacity to its customers through the EPU project – and will complete that work in early 2013 as planned. Upon completion, FPL estimates that approximately 490 MWe of baseload, non-greenhouse gas emitting generation will be provided by the EPU project for its customers, all without expanding the footprint of its existing nuclear generating plants. In addition to the 31 MWe already being provided by the EPU project, FPL will bring on line approximately 336 MWe by the end of 2012. Completion of the EPU project in 2013 will add approximately 123 MWe, for a total of 490 MWe. The substantial benefits to FPL's customers from this additional nuclear generation will be realized at least a decade earlier than if additional nuclear generation were to be delivered solely through new nuclear units, and at a significantly lower cost per kilowatt.

Q. Please elaborate on the managerial and technical challenges of the project.

A. The EPU project poses extraordinary managerial and technical challenges. FPL's EPU project represents one of the largest and most complex nuclear design, engineering, and construction projects undertaken in the nuclear industry since the construction of the previous generation of U.S. nuclear plants. As of April 2012, FPL estimates that the project will require the orchestration and management of over 4 million man-hours of engineering and total EPU project work of approximately 20 million man-hours.

This is the equivalent of approximately 1,800 person-years of engineering time and 10,000 person-years of total EPU work time. All of this work is being conducted on four operating nuclear units with live steam, electrical and nuclear fuel equipment and systems. FPL is committed to efficiently managing all of this work in a way that maximizes the benefits of the EPU project for FPL's customers and in a manner that maintains nuclear and industrial safety.

Q. Is the project remaining on schedule for completion?

A. Yes. Despite all of its complexities, FPL is progressing with the implementation of the EPU project on the expedited basis approved by the Commission. At the time of this filing, the status of the EPU project can be summarized as follows:

- Approximately 90% of design engineering is complete;
- Approximately 12 million out of approximately 20 million hours of EPU work are complete;
- Five out of eight EPU outages are complete and we are in the midst of the sixth; and
- 31 MWe of nuclear power from the project are already serving customers.

Q. Where do you expect the project to be by year-end 2012?

A. A huge amount of implementation work is underway and will be completed this year. By the end of 2012, progress on the EPU project will reflect the following:

- 367 MWe will be serving customers
- Seven out of eight EPU outages, plus a short mid-cycle implementation outage, will be complete;
- The design engineering will be complete; and

- Approximately 18 million out of approximately 20 million hours of EPU work will be complete.

Q. What magnitude of investment is FPL making in the EPU project during 2012 and 2013?

A. As detailed in this testimony and accompanying exhibits, FPL plans to invest a total of approximately $1,100 million during 2012 and approximately $200 million during 2013 in the Uprate project. This investment will be recovered through base rates over the decades that the Uprate project will provide service. In comparison, consistent with the Nuclear Cost Recovery statute and rule, FPL is requesting only the recovery of carrying charges, O&M expenses, and partial-year revenue requirements of approximately $130 million for the EPU project through the NCRC in 2013.

FPL also plans to place the remaining Uprate project components into service. The estimated equipment in-service amounts for 2012 are approximately $1,640 million, and for 2013 are approximately $720 million. Please note that the dollar values in my testimony are the forecasted EPU resource requirements, and do not include certain accounting adjustments made by FPL Witness Powers, unless noted otherwise.

Q. How do these project costs translate into FPL's nuclear cost recovery clause request for 2013?

A. The EPU amount contributes to a total Company request of approximately $151 million in 2013, which includes Turkey Point 6 & 7 cost recovery as described by FPL Witness Powers. This equates to a residential customer monthly bill impact of $1.68 per 1,000 kWh. This is ~~fifty two~~ fifty-five cents per 1,000 kWh less and ~~24%~~ 25% lower than FPL's currently authorized nuclear cost recovery amount.

Q. Has FPL updated its non-binding cost estimate for the project?

A. Yes. Along with the work described above, FPL has worked to update the non-binding total cost estimate range to reflect the best information known at this time, in light of the substantial progress that has been made on the project and continuing diligence in the management of vendor resources and projections.

Q. What information is available this year that was not available last year?

A. As described in more detail below, last year FPL had completed approximately 36% of EPU engineering at the time of this filing. Today, over 90% of engineering is complete, with remaining outage work that is very similar to work that has already been completed during prior outages. Additionally, FPL has been able to perform a great deal of detailed construction planning which makes knowing what is required for the job more definitive in terms of people, equipment, and materials.

Q. What is the revised non-binding cost estimate range?

A. The revised non-binding cost estimate range is $2,950 million to $3,150 million, including transmission and carrying costs. For purposes of the 2012 economic feasibility analysis, FPL has utilized a total project cost estimate of $3,050 million.

Q. Is completing the project cost-effective at the new estimate?

A. Yes. While the current non-binding cost estimate is higher than the non-binding cost estimate used in the economic analyses conducted last year, the testimony and exhibits of FPL Witness Dr. Sim show that completion of the EPU project continues to be projected to provide large economic benefits for FPL's customers. For example, FPL Witness Dr. Sim's Exhibit SRS-8 shows that in the Medium Fuel Cost, Environmental II cost scenario, the project is currently expected to reduce costs to customers by more than $296 million in cumulative present value of revenue requirements compared to a plan without the EPU project. To the extent natural gas and environmental compliance costs increase in the future above their current projected values, the cost savings attributable to the EPU project being in FPL's portfolio would also increase.

Q. Please provide the specific facts and figures of the benefits of the EPU project for FPL's customers.

A. After accounting for all relevant updates, including lower than previously forecasted natural gas prices, completing the EPU project is the most economic choice for customers in 6 out of 7 potential future fuel and environmental cost scenarios. Further, FPL expects that the EPU project will:

- Provide estimated fossil fuel cost savings for customers of approximately $114 million in the first full year of operation;
- Provide estimated fossil fuel cost savings for FPL's customers over the life of the plants of approximately $3.8 billion (nominal);

- Diversify FPL's fuel sources by decreasing reliance on natural gas and foreign oil. Addition of the EPU project will reduce FPL's reliance on natural gas by 3% beginning in the first full year of operation, providing an important hedge against volatile natural gas prices, and helping to reduce reliance on Florida's limited natural gas transportation infrastructure;
- Provide a total amount of energy that is equivalent to the usage of 311,578 residential customers each year;
- Reduce annual fossil fuel usage by the equivalent of 6 million barrels of oil or 41 million mmBTU of natural gas annually;
- Reduce system CO_2 emissions by an estimated 32 million tons over the life of the plants; and
- Provide generation in the Southeast portion of FPL's service area, helping to mitigate against a growing generation-load imbalance.

The quantifications of these benefits are set forth in FPL Witness Dr. Sim's testimony and Exhibit SRS-1. These benefits are also discussed in the Long Term Feasibility section of my testimony, and are presented in my Exhibit TOJ-15.

Q. Are there additional benefits being provided by the EPU project?

A. Yes. FPL's long-term investment in the EPU project is being implemented by employing a lot of people at a time when jobs matter a great deal. Exhibit TOJ-16 shows that on average, more than 3,400 people are being employed – nearly all in Florida -- throughout 2012 to accomplish the uprate. Exhibit

TOJ-16 also shows that a high level of employment on the EPU project will continue through the first quarter of 2013, with on average nearly 2,000 people being employed to complete the project. This extensive workforce includes thousands of professional, technical, and administrative workers. Employment of these workers represents a large portion of FPL's total anticipated investment in 2012 and 2013 of $1,100 million and $200 million, respectively.

Q. Please describe how the remainder of your testimony is organized.

A. My testimony includes the following sections:

- Project Status and Schedule
- True-Up to Original Cost and Updated Cost Estimate Range
- Long Term Feasibility
- Project Management Internal Controls
- 2012 Actual/Estimated Construction Activities and Costs
- 2013 Projected Construction Activities and Costs

PROJECT STATUS AND SCHEDULE

Q. Please provide an overview of the current status of the Uprate project.

A. In 2012, FPL expects to complete the Engineering Analysis Phase following the Nuclear Regulatory Commission (NRC) approval of the Turkey Point, St. Lucie Unit 1 and St. Lucie Unit 2 EPU License Amendment Requests (LARs). FPL will also complete the Long Lead Procurement and the Engineering

Design Modification phases. The Implementation phase is in full swing, with the planned completion of three outages during 2012 and the final EPU outage in early 2013. FPL has successfully completed five of eight planned EPU outages in the Implementation Phase. Turkey Point Unit 3 is presently in its second (and last) EPU outage and the second (and last) Turkey Point Unit 4 outage is planned to start in November of this year. The second (and last) outage at St. Lucie Unit 2 will begin in August of this year. Additionally, FPL plans to conduct a brief mid-cycle outage at St. Lucie Unit 1 this year, which will be the final EPU outage for that unit.

Q. Please describe the Federal licensing needed for the EPU Project.

A. FPL must obtain a license amendment to the renewed NRC operating licenses for St. Lucie Unit 1, St. Lucie Unit 2, and Turkey Point Units 3 and 4 in order to operate at the EPU condition. We expect to receive NRC approval of the Turkey Point EPU LAR in late April or early May 2012. For St. Lucie Unit 1, we expect to receive a favorable review from the NRC Advisory Committee on Reactor Safeguards (ACRS) subcommittee by the end of April 2012, and we expect NRC approval no later than July of this year. For St. Lucie Unit 2, we expect a favorable review from the ACRS subcommittee in June and NRC approval in August.

FPL expected to receive its EPU LAR approvals much sooner. However, NRC resource constraints resulted in delays in LAR reviews and approvals. In order to minimize the financial and timing impacts on the project, FPL developed a plan for a 2012 St. Lucie Unit 1 mid-cycle outage. The mid-cycle outage duration is planned to be several days; long enough to change instrumentation set points and other minor modifications necessary for operation in the approved uprate condition. The outage will also allow FPL to implement processes and procedures for operating the plant in the uprate condition. The Turkey Point Unit 3 outage start date was also modified to allow more time for the NRC to approve the Turkey Point EPU LAR and to allow for further completion of pre-outage work.

Q. Do industry-wide developments affect the NRC's review of FPL's EPU LARs?

A. Yes. As discussed in my March 1, 2012 testimony, the earthquake and tsunami in Japan and the earthquake in Virginia have adversely impacted NRC staff resources, and consequently, extended the timeline for the review of FPL's EPU LAR submittals as mentioned above. This is resulting in significant cost and schedule impacts to the EPU Project. Additionally, just prior to the Turkey Point ACRS subcommittee meeting, the NRC raised an issue with the Westinghouse fuel performance model with respect to a non-FPL plant. This industry development required FPL to perform additional LAR engineering activities in support of its Turkey Point and St. Lucie EPU LARs. This issue is now completed with respect to Turkey Point, and FPL expects it to be completed with respect to St. Lucie when the EPU LARs go to the ACRS subcommittees.

Q. Are there any remaining Local and/or State permits needed for the EPU Project?

A. No. State and local permitting has been completed for the EPU Projects. Requirements of the revised permits are being implemented.

Q. Please describe the current EPU project schedule.

A. The project schedule continues to support overall completion in 2013. EPU work on three out of four reactors will be finished by the end of this year, with the fourth completed in March 2013. Exhibit TOJ–17, Extended Power Uprate Project Schedule as of April 23, 2012, presents the EPU Project schedule and the overlapping phases of the work activities. This schedule reflects the outage duration revisions that were discussed in my March 1, 2012 testimony, the decision to change the St. Lucie Unit 2 and the Turkey Point Unit 3 outage start dates, and the addition of the short mid-cycle outage for St. Lucie Unit 1.

Q. Please explain the benefits of changing outage start dates.

A. The revisions to the outage start dates provide greater assurance that the NRC will complete the reviews and approvals needed before the upgraded units are placed into service. In the case of Turkey Point, approval of the EPU LAR is needed before Unit 3 can return to service following its final EPU outage. It also allows for the completion of more pre-outage work prior to entering the outage. Finally, such changes allow for FPL to maximize its nuclear fuel usage.

TRUE-UP TO ORIGINAL COST AND UPDATED COST ESTIMATE RANGE

Q. Did FPL prepare a true-up of the total project costs in 2012?

A. Yes. FPL's 2012 True-up to Original (TOR) schedule is included in TOJ-14.

Q. Have you prepared a current true-up of the total project costs through the current reporting period?

A. Yes. Exhibit TOJ-14 includes the 2013 TOR schedules that compare the current projections to FPL's originally filed project costs. The 2013 TOR schedules provide information on the project costs through the end of 2013.

Q. Has FPL updated its total non-binding cost estimate for the project?

A. Yes. Consistent with the Commission's direction in Order No. PSC-09-0783-FOF-EI, FPL has updated its non-binding cost estimate for the EPU project. FPL has developed an updated cost estimate range for the EPU project that reflects increased scope that is necessary to support NRC regulatory requirements, design evolution, and construction and implementation logistics. It also reflects costs associated with schedule changes made primarily to accommodate extended NRC LAR review and approval timeframes. The updated cost estimate range is approximately $2,950 million to $3,150 million, including transmission and carrying costs, as shown on NFR Schedule TOR-2.

Q. Does the stage of the project affect the project cost forecasting process?

A. Yes. As I have testified in earlier years, the progression of project activities each year provides FPL with additional information enabling it to revise its non-binding cost estimate. At the time of FPL's May 2, 2011 filing, which included its last non-binding cost estimate range, the EPU project had completed 36% of total engineering, representing much less information than is currently available at the time of this filing. At the time of this filing, approximately 90% of the EPU engineering is complete. Additionally, in May 2011, only 81 of 209 modification packages had reached the 90% complete stage, as compared to the 206 of 220 modification packages that are currently at the 90% complete stage. Modification packages must reach 90% before detailed construction planning can commence.

Q. What does detailed construction planning include, and how does it affect the preparation of cost estimates?

Detailed construction planning includes engineers actually walking-down the areas of the plant that will be modified to assess exactly how to physically and mechanically implement the final modification design taking into account the actual existing physical configuration of the plant, including the effects on components and equipment that are not part of the system being modified. This process disclosed the need for much more extensive construction efforts than had been previously estimated without the benefit of final modification designs.

Detailed construction planning, including system walkdowns, enables FPL to determine with a much higher degree of precision and specificity the actual steps and sequences of actions needed to physically construct the modification in the plant. This includes figuring out the detailed logistics, identifying and planning for the temporary relocation or permanent removal of any interferences encountered between modified equipment and existing plant systems, quantifying how much of different commodities such as feet of wire, feet of piping and consumables will be required, as well as the task of identifying and engineering plant structural modifications to support the EPU modifications. As a simple example, some of the major generating equipment being installed is a lot larger and heavier than the existing equipment that it replaces. Accordingly, to accommodate the uprate condition the structure of the plant itself needs to be strengthened to support the weight and safely deal with the changed mechanical stresses caused by the larger equipment.

All of this additional implementation work requires additional manhours for engineering, construction and project support, causing the cost estimate to increase. Additionally, the need for an augmented construction organization and infrastructure to support the additional work has been identified and included in the estimate.

Q. **Could the changes to FPL's non-binding cost estimate associated with construction engineering have been determined by FPL at an earlier stage of the project?**

A. No. These construction details, and associated cost estimates, could only be developed once the detailed engineering was substantially completed, which then enabled FPL to determine what work is required in the plant to implement the modifications.

Q. Please describe the process of revising FPL's non-binding cost estimate range.

A. The process to revise FPL's non-binding cost estimate was completed in April 2012. The process to revise FPL's non-binding cost estimate range began with the receipt of the EPC vendor, Bechtel's, Estimate at Completion (EAC) for the Turkey Point EPU work in November of 2011. (The Turkey Point EAC, and FPL's response, was described in my March 1, 2012 testimony.) This was Bechtel's first opportunity to provide an estimate that included detailed construction costs since engineering design was only then approaching 90% on a majority of modifications. Bechtel's EAC was higher than previous estimates, reflecting increased scope that is necessary to support NRC regulatory requirements, design evolution, and construction and implementation logistics.

Q. What did FPL do after it received the Bechtel EAC in November, 2011?

A. In December 2011 through April 2012, FPL performed extensive due diligence on Bechtel's Turkey Point EAC as well as revised estimates for St. Lucie. This included enormous amounts of engineering, corporate staff and executive work to analyze the EAC. In order to better understand and analyze the basis for the EAC, FPL's due diligence included several trips to Bechtel in Frederick, Maryland by FPL senior management and several trips to FPL's headquarters by Bechtel senior management.

Q. What other kind of work did FPL do to review the EAC with Bechtel?

A. FPL worked with Bechtel and High Bridge to perform a detailed review of all inputs and assumptions used in estimating the remaining work at each plant. The detailed review work included three days of lengthy sessions with senior management from FPL and Bechtel. Those sessions built upon the close analyses that FPL had already performed to scrutinize in detail key elements of the cost estimate, including: (i) units of productivity; (ii) quantifications of commodities; (iii) "implied complexity factors" which are an industry standard measure of how complicated work is to perform; (iv) labor rates; and (v) professional rates, among other cost estimate inputs. The focus of these detailed reviews was to validate that the inputs being used in the cost estimating process were not overly conservative.

Q. Did FPL's process of closely scrutinizing the Turkey Point EAC and St. Lucie estimate result in reductions in the cost estimate?

A. Yes. FPL and Bechtel's joint review identified a number of opportunities for efficiencies and process improvements, for example, with respect to how crews are organized to perform certain scopes of work. In total, this process of closely scrutinizing the EAC resulted in an approximately $89 million reduction to the Turkey Point EAC.

Q. Did FPL take further steps to reduce estimated project costs?

A. Yes. After exhausting all available options to optimize the EPU project work and realize potential efficiencies, FPL and Bechtel began negotiations for significant price reductions and concessions, and brought those negotiations to a successful conclusion.

Q. Did you personally seek price reductions and concessions?

A. Yes. I held numerous meetings with Bechtel to negotiate price reductions, the last few of which were also attended by senior management from each company.

Q. What price reductions and concessions did FPL and Bechtel negotiate?

A. FPL and Bechtel agreed to a number of price reductions and concessions that benefit FPL's customers by reducing the estimated cost of the project. These include Bechtel's agreement to:

- Forego its incentive fee - a fee typically paid based on performance, in addition to time and material payments for major construction projects such as the EPU project, and which fee had been provided for in the original contract between FPL and Bechtel;
- Reduce its daily living allowance;
- Reduce its billable rate for Field Non-Manual employees; and
- Waived its escalation of rates.

Further, Bechtel negotiated a wage freeze with its union trade workers and agreed to obtain a reduction on its subcontractor charges.

Q. How much will the price reductions and concessions FPL negotiated benefit customers?

A. FPL estimates that in total these concessions will reduce the project cost by approximately $46 million.

Q. What is the combined effect of the cost reductions from closely scrutinizing the cost estimates and obtaining price reductions and concessions?

A. These efforts produced total cost reductions of $135 million, which represents a 14% reduction to the Engineering and Construction to-go forecast dated March 31, 2012.

Q. After accounting for all the above cost reductions, why is the EPU project still estimated to cost more than estimated last year?

A. The primary cost drivers can generally be described as (i) NRC regulatory requirements and delays, (ii) design evolution, and (iii) construction implementation and logistics.

About $110 million of the project cost estimate increase can be attributed to those modifications that are required to meet NRC requirements, as well as costs associated with outage schedule changes caused by delays in NRC LAR approvals.

About $150 million of the project cost estimate increase can be attributed to design evolution. Design evolution refers to costs associated with the iterative engineering process needed to address issues discovered during engineering design, such as the need for structural upgrades caused by the ultimate weight and dynamic loading of new equipment.

About $220 million of the project cost increase can be attributed to construction implementation and logistics. Construction implementation and logistics refers generally to the issues and related costs that cannot be known until designs are complete (or at the 90% complete stage) and detailed construction planning and plant walkdowns can commence. Costs identified by detailed construction planning (the conversion of design engineering into detailed steps required to complete the scope of work) and plant walkdowns include, for example, the need to construct temporary decking for equipment lay down space and crane/rigging methodology adjustments. Design evolution and construction implementation issues necessarily overlap.

Q. What factor ultimately drives the project cost estimate?

A. Ultimately it is the human effort required to complete the project and the number of people that are required to be employed for that effort that drives the project cost estimate. The increased labor and required infrastructure to manage that labor is the consistent cost driver within each of the above categories. The EPU project is requiring many more activities, which require many more people, and a bigger organization to manage all the work.

As mentioned above, detailed construction planning can only commence when engineering designed modification packages are 90% complete. Then, FPL and its vendors can perform walkdowns and develop subcontractor estimates, labor estimates, security, commodities, logistics, and the oversight structure needed to support the implementation activities. As discussed earlier, often, new construction "scope" is revealed that could not have been known prior to detailed construction planning, and the time and number of personnel needed to plan for and execute the construction activities for a particular modification must be increased.

Q. Please provide an example of how performing detailed construction planning, after completion of the design engineering for a modification, results in increased estimated costs.

A. For example, consider the PTN Normal Containment Coolers (NCCs) modification. A NCC cools the air inside the reactor containment building during normal plant operations. The new NCCs are much bigger and heavier than the original coolers. This means significant structural steel reinforcement is needed to bear their weight. This is an example of the iterative design effects of modifications that increase scope.

Then, from the detailed constructability walkdowns in the reactor containment building, it was determined that the lay-down space inside the reactor containment was not sufficient. That means we needed to install temporary steel decking inside the plant simply to provide the lay-down space for equipment necessary to implement the NCC work. Walkdowns also showed that interferences must be removed in order to install the new NCC subcomponents. Additionally, detailed work planning identified that a temporary supplemental crane system had to be installed inside containment to support the large number of lifts required to implement the work. All of these issues have contributed to the increased complexity – and cost – of the NCC replacement scope.

Q. Are there other examples of this type of increased construction complexity which resulted in increases in the cost estimate?

A. Yes. Additional examples are attached as Exhibit TOJ-18.

Q. What is the basis for the non-binding cost estimate range?

A. The low end of the non-binding cost estimate range is based on the project forecast as of March 31, 2012 and includes allowances for known pending changes. The high end of the non-binding cost estimate range starts with the low end and adds contingency for scope growth and discovery for the remaining outages based on current outage performance.

LONG TERM FEASIBILITY

Q. What total project cost did FPL use for purposes of the 2012 economic feasibility analysis?

A. FPL performed its feasibility analysis with an estimated going forward project cost figure of $1,590 million, which includes transmission and carrying costs. This reflects FPL's project manage-to estimate of $3,050 million approved in mid-April 2012 less sunk costs as of year-end 2011, consistent with the treatment of sunk costs provided for in Commission Order No. PSC-09-0783-FOF-EI and Order No. PSC-11-0547-FOF-EI. FPL selected the $3,050 million manage-to estimate as the basis for the feasibility analysis because it was more conservative than the project forecast at the time of the analysis.

Q. What assumed megawatt output did FPL use for purposes of the economic feasibility analysis?

A. FPL assumed that the Uprate would provide an additional 490 MWe for feasibility analysis purposes.

Q. Please summarize the results of the EPU economic feasibility analysis.

A. As discussed in detail by FPL Witness Dr. Sim, the most current feasibility analysis affirms the cost-effectiveness and benefits associated with completing the Uprate project, demonstrating net savings in 6 out of 7 analyzed scenarios of fuel costs and environmental compliance costs.

Q. Are there other system benefits provided by the EPU project?

A. Yes. As described and supported by FPL Witness Sim, FPL expects that the EPU project will:

- Provide estimated fossil fuel cost savings for customers of approximately $114 million in the first full year of operation;
- Provide estimated fossil fuel cost savings for FPL's customers over the life of the plants of approximately $3.8 billion (nominal);
- Diversify FPL's fuel sources by decreasing FPL's reliance on natural gas and foreign oil. Addition of the EPU project will reduce reliance on natural gas by 3% beginning in the first full year of operation, providing an important hedge against volatile natural gas prices and

helping to reduce reliance on Florida's limited natural gas transportation infrastructure;

- Provide a total amount of energy that is equivalent to the usage of 311,578 residential customers each year;
- Reduce annual fossil fuel usage by the equivalent of 6 million barrels of oil or 41 million mmBTU of natural gas annually;
- Reduce system CO_2 emissions by an estimated 32 million tons over the life of the plants; and
- Provide generation in the Southeast portion of FPL's service area, helping to mitigate against a growing generation-load imbalance.

Q. Please describe the benefits to the Southeast portion of FPL's service area in more detail.

A. The EPU project will contribute to grid stability by producing power where it is consumed. Growth in electrical load in the Southeast area within FPL's service area means that FPL must either add new generation to that area or rely on transmission lines to import the needed energy. All else equal, adding locally-sited generation contributes to grid stability and is more reliable than relying on transmission lines that cover long distances and are susceptible to interferences from storms or other issues beyond FPL's control that could result in outages. When generation is sited closer to where it is consumed, fewer people will be affected when storms take out transmission lines. Additionally, increasing generation at the Turkey Point site reduces system transmission line losses, meaning more power is available for customers to use.

Q. Has FPL examined other aspects of EPU project feasibility in addition to economics?

A. Yes. FPL continuously assesses the financial, technical, and regulatory aspects of the EPU project, and the project remains feasible.

Q. Is it technically feasible to accomplish the Uprate project?

A. Yes. In fact, the project is fast approaching completion.

Q. Is it feasible to finance the Uprate project?

A. Yes. The Uprate project is financed by the general capital FPL raises each year, and adequate amounts of capital will be obtained to complete the project.

Q. Is it feasible to obtain all necessary licenses and permits?

A. Yes. FPL has completed the state licensing/permitting process. FPL has submitted all necessary LARs to the NRC and expects final approval in 2012.

Q. Are there other aspects to feasibility that FPL has examined?

A. Yes. Inherent to the project management process is the recognition of factors such as resource availability/constraints, potential cost escalations, and industry-critical events such as the cancellation of the Yucca Mountain spent fuel disposal project and the recent events in Japan following the earthquake and tsunami and the Virginia earthquake. FPL monitors these and other factors. None of these issues has caused the project to cease being feasible.

Q. Are these aspects required to be included in the feasibility analysis set forth in Rule 25-6.0423(5)(c)5, F.A.C.?

A. No. FPL's economic feasibility analysis sponsored by FPL Witness Dr. Sim is being provided in satisfaction of Rule 25-6.0423(5)(c)5, F.A.C. On February 4, 2010, Commission Staff requested that FPL address these feasibility-related topics. Accordingly, FPL has summarized its assessment of the non-economic topics related to feasibility in response to Staff's request.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. Please describe the project management internal controls that FPL has in place to ensure that the project is effectively managed.

A. As described in detail in my March 1, 2012 testimony, FPL has robust project planning, management, and execution processes in place. FPL utilizes a variety of mutually reinforcing schedules and cost controls, and draws upon the expertise provided by employees within the project team, employees within the separate Nuclear Business Operations group, and executive management. Those controls continue to be utilized in 2012.

One of the key project management tools utilized by the EPU team is the project Risk Register. Risk matrices, such as EPU's Risk Register, are a common project management tool. The Risk Register allows for identified risks – including potential increases to scope – to be logged and assessed in terms of cost and probability. Resolutions are also tracked in the Risk Register, which may include avoidance or mitigation of the identified risk, or incorporation of the particular item within the project scope. Periodic presentations are made to executive management where risks, costs, and schedules are discussed.

Q. Have there been any changes in the project management system FPL is using to ensure that the 2012 actual/estimated and 2013 projected costs are reasonable?

A. Yes. The EPU project management processes are adjusted to implement and use industry best practices through self-assessment, peer reviews, independent third party reviews, internal and external audits, and executive oversight and direction. In 2012, FPL made adjustments to controls related to site report generation, staffing ramp levels, work scope assignments, and outage implementation interface.

Q. Are any internal audit activities underway?

A. Yes. The annual internal audit of the EPU financials is currently being conducted, which provides a review of project expenditures through 2011. FPL anticipates that this audit will be completed this summer. An internal audit will be conducted next year to review 2012 expenditures.

2012 ACTUAL/ESTIMATED CONSTRUCTION ACTIVITIES AND COSTS

Q. Please summarize the activities planned for and being implemented in 2012.

A. In 2012, FPL is supporting the NRC's final review and approval of the LARs. The Long Lead Equipment procurement phase is nearing completion as milestone payments are made and necessary equipment is delivered to support the outages in 2012. The Engineering Design Modification Phase is nearly complete with the EPC vendor completing the modification packages and supporting construction planning activities for the outages. The Implementation Phase is in full swing with the planning and execution of the major construction activities during the 2012 outages.

Q. Please describe the Engineering Design and Implementation work that will occur at St. Lucie.

A. In 2012, the EPU project will:

- Complete remaining engineering design work to support detailed construction planning for the implementation of modifications during the final St. Lucie EPU outages;
- Complete detailed construction and logistics planning required to perform the modifications during the final St. Lucie EPU outages;
- Complete the outage at St. Lucie Unit 1 (outage was completed on April 21, 2012), which includes the installation of the following major equipment:
    - Containment Mini-Purge System
    - High Pressure Turbine
    - Moisture Separator Reheater
    - Low Pressure Turbine

- Main Generator Stator Rewind
- Main Generator Rotor
- Feedwater heaters #5A & B
- Leading Edge Flow Meter
- Heater Drain Pumps and Motors
- Main Feedwater Pump
- Heater Drain Control Valves
- Main Transformer Coolers;

- Execute the mid-cycle outage at St. Lucie Unit 1 upon approval of the EPU LAR, which will provide 129 MWe when the unit is returned to service;
- Execute the final outage at St. Lucie Unit 2 beginning in August 2012 and ending in November 2012, which includes installation of the following major equipment and is expected to add 84 MWe to the 31 MWe already achieved (for a total of 115 MWe from this unit) when the unit is returned to service:
  - High Pressure Turbine
  - Moisture Separator Reheaters
  - Feedwater Heaters #5A & B
  - Feedwater Heaters #4A & B
  - Leading Edge Flow Meter
  - Heater Drain Pumps
  - Main Feedwater Pump

- Heater Drain Control Valves
- Isophase Bus Duct Cooling System
- Main Transformer

(A diagram of this outage work is attached as Exhibit TOJ-19).

Q. Please describe the Engineering Design and Implementation work that will occur at Turkey Point.

A. In 2012, the EPU project will:

- Complete remaining engineering design work to support detailed construction planning for the implementation of modifications during the final Turkey Point EPU outages;
- Complete detailed construction and logistics planning required to perform the modifications during the final Turkey Point EPU outages;
- Execute the final outage at Turkey Point Unit 3 beginning in February 2012 and ending in August 2012, which includes installation of the following major equipment and will provide an additional 123 MWe from this unit when the unit is returned to service:
    - Normal Containment Coolers
    - High Pressure Turbine Modifications
    - Main Generator Rotor
    - Moisture Separator Reheaters
    - Main Condenser
    - Condensate Pumps and Motors
    - Turbine Plant Cooling Water heat Exchanger

- Main Feedwater Pumps Rotating Elements
- Feedwater heaters #5A & B
- Feedwater heaters #6A & B
- Isophase Bus Duct System

(A diagram of this outage work is attached as Exhibit TOJ-20. Pictures of the Turkey Point site taken during this outage are also attached as Exhibit TOJ-21.)

- Begin final outage at Turkey Point Unit 4 in November 2012 (to be completed in March 2013), which will add 123 MWe when it is returned to service.

Q. Did FPL project its 2012 EPU costs for these types of activities in 2011?

A. Yes. FPL prepared and filed a projection of 2012 costs in Docket No. 110009-EI.

Q. Has FPL trued-up these projections to develop 2012 Actual/Estimated costs?

A. Yes. Exhibit TOJ-14 presents FPL's 2012 Actual/Estimated costs.

Q. Please describe how FPL developed its 2012 Actual/Estimated costs.

A. Actual 2012 costs come from a monthly download of project charges from the FPL accounting system. These charges are for materials and services from multiple vendors and are applied to the total project cost on an ongoing basis. Each charge is applied using a coding structure which defines which of the units the charges apply to. For project management purposes, the charges are subsequently broken down by major vendor or appropriate cost control grouping which ultimately supports project management analysis and forecasting.

The estimated project costs were developed from Project Controls forecasts derived from the best available information for all known project activities in 2012. Included in the forecasts are the vendor long lead material contracts that have scheduled milestone payments in 2012. Cash flows are based upon the latest fabrication and delivery schedule information. Each major labor related services vendor forecast is based upon the original awarded value and all approved changes. Added to this, where applicable, would be an estimate of any known pending changes to arrive at a best forecast at completion for each vendor. Owner engineering and project management support forecasts are derived from approved detailed staffing plans. Cash flows are developed for each approved position based on the expected assignment duration and expected overtime, where applicable. The large construction related vendor forecasts are based upon previous experience, known scope(s) of work, productivity factors related to outage conditions and prevailing pertinent wage rates. Cash flow projections for items identified in the Risk Register are based upon anticipated engineering, material procurement, and outage implementation time horizons.

Q. What types of costs does FPL plan to incur for the Uprate project in 2012?

A. As indicated in Exhibit TOJ-14, Schedule Actual/Estimated (AE) – 4 and AE-6, and summarized in Exhibit TOJ-23, EPU Actual/Estimated 2012 Summary Costs Tables, Tables 1 through 9, costs were incurred in the following categories: Licensing; Engineering & Design; Permitting; Project Management; Power Block Engineering, Procurement, etc.; Non-Power Block Engineering, Procurement, etc.; EPU Recoverable O&M; and Transmission Capital and Recoverable O&M. Table 1 is a summary of each of the categories showing the 2012 actual/estimated amounts. The amounts shown in the exhibit are slightly different than the NFR schedules as footnoted on the exhibit.

Q. Please describe the 2012 activities in the License Application category.

A. For the period ending December 31, 2012, License Application costs are estimated to be $26,071,019 as shown on Table 2 of Exhibit TOJ-23. These License Application costs consist primarily of payments to vendors for support in responding to NRC Requests for Additional Information as necessary in 2012, and NRC fees. This is approximately $20.8 million more than projected due to increased scope, additional engineering analyses and fees required by the NRC for completing the licensing effort.

Q. Please describe the 2012 activities in the Engineering and Design category.

A. For the period ending December 31, 2012, Engineering and Design costs are estimated to be $24,666,015 as shown on Table 3 of Exhibit TOJ-23. This amount consists primarily of FPL's engineering and design work in support of review and approval of the engineered design modification packages prepared for the St. Lucie and Turkey Point sites by Bechtel, the EPC for the EPU Project, and other vendors. This is approximately $13.6 million more than projected due to the need for additional resources to support the increased scope and complexity for design engineering.

Q. Please describe the 2012 activities in the Permitting category.

A. For the period ending December 31, 2012, Permitting costs are estimated to be $0 as shown on Table 4 of Exhibit TOJ-23.

Q. Please describe the 2012 activities in the Project Management category and how those activities help ensure that the Uprate project will be completed on a reasonable schedule and at a reasonable cost.

A. For the period ending December 31, 2012, Project Management costs are estimated to be $52,273,140 as shown on Table 5 of Exhibit TOJ-23. This category includes FPL and contractor management personnel at each of the sites and those in the Juno Beach Office. This work and the associated costs are required to ensure the Uprate project is managed in an efficient and cost-effective manner. This is approximately $25.9 million more than projected due to additional support needed for the increased number and types of resources and implementation of the EPU outages scheduled for 2012.

Q. Please describe the 2012 activities in the Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2012, Power Block Engineering and Procurement costs are estimated to be $954,929,052 as shown on Table 6 of

Exhibit TOJ-23. This is approximately $232.3 million more than projected. The primary drivers include the deferral of long lead equipment payments from 2011 into 2012 (approximately $30 million), increased Siemens labor costs (approximately $50 million), increased EPC labor and management costs (approximately $251 million), increased Station Indirect Outage costs (approximately $6 million), and the increased infrastructure (approximately $98 million) – all of which is required to implement the much more complex construction effort as determined by the completion of modification design engineering and detailed construction planning. These variances, however, are offset by less than planned turbine generator equipment costs (approximately $11 million), reductions to scope and contingency (approximately $189 million), and certain accounting adjustments (approximately $3 million).

This amount is primarily for the development of the engineering design modification packages and for the implementation of the scheduled work for the four outages scheduled for 2012. This work includes preparation of the modification packages (part of the Engineering Design Modification Phase); the development of directions for the removal, replacement and/or modification of components, equipment, systems and structures as needed to support the uprate condition; and the performance of field walkdowns by Bechtel and other vendors. This amount also includes the next level of detailed implementation activities, including the development and issuance of step-by-step work instructions for the construction and integration of the modifications into the physical plant structures and systems. The second part of this phase is the actual, physical execution of the construction work and management of the logistics in the plant, most of which is occurring in the scheduled 2012 outages.

Some modifications can be performed when the units are operating, reducing the complexity of the outage and limiting the outage duration. FPL evaluates the risk to the continued operation of the unit and if determined to be an acceptable risk, the modifications will be performed while the unit is on line. One such modification is the Control Room Ventilation system modification at Turkey Point, which is required to satisfy the NRC's Alternative Source Term license requirements. Additionally, a portion of the turbine controls were replaced at the St. Lucie units while those units were on-line.

Procurement costs include the purchase of long lead equipment items and progress payments to manufacturing vendors. FPL is continuing to make required milestone payments on previously executed contracts for the procurement of major equipment.

Q. **Please describe the 2012 activities in the Non-Power Block Engineering, Procurement, Etc. category.**

A. For the period ending December 31, 2012, Non-Power Block Engineering costs are estimated to be $1,078,425 as shown on Table 7 of Exhibit TOJ-23.

This is approximately $0.6 million more than projected due to the additional support needed for the increased number of resources required by the constructability complexity for the EPU outages in 2012.

This category consists primarily of the following: engineering, permitting, and construction of temporary facilities; upgrades to training simulators; and additional dry cask storage for spent fuel.

There are fabrication areas created to pre-fabricate piping and valves, which reduces the outage time because work can be performed prior to the outage and at the same time as other work, instead of in a series of field activities during the outage. Warehouses are used to store and stage delivered materials for the EPU project prior to installation and to provide areas for the training and qualification of craft labor. A site training and qualification area is necessary to ensure the sites have the needed qualified craft labor support to perform the many tasks needed to remove, install or modify plant equipment.

This category also includes the modifications to each site's operator training simulators. The training simulators require modifications to reflect the equipment and operating parameters in the uprate condition.

Q. Please describe the 2012 actual/estimated recoverable O&M costs.

A. Actual/Estimated recoverable O&M costs for the EPU project in 2012 include $15,283,333 for EPU, shown on Table 8 of Exhibit TOJ-23, and $2,606 for

Transmission, as shown on Table 9 of Exhibit TOJ-23. Recoverable O&M primarily consists of costs for performing work activities that do not meet FPL's capitalization criteria and an estimate of obsolete materials that will be expensed as a result of modifications completed in 2012. This is approximately $9.7 million more due to a determination that certain activities did not meet FPL's capitalization criteria.

Q. Please describe the 2012 activities in the Transmission category.

A For the period ending December 31, 2012, Transmission costs are estimated to be $27,387,533 as shown on Table 9 of Exhibit TOJ-23. This amount is primarily related to costs associated with the upgrades to the main transformers and plant yard electrical components at the sites. This is approximately $.1 million more than projected due to some transmission outage work accelerated into 2012 and some deferred from 2011 into 2012 due to line and switchyard availability.

Q. Please describe the equipment going into service in 2012.

A. Exhibit TOJ-22, 2011 Extended Power Uprate Project Work Activities, is a listing by outage of major 2012 work activities for PSL Unit 1, PSL Unit 2, and PTN Unit 3. To the extent the work activities are subject to capitalization as units of property and the modification is completed in 2012, the plant components will be placed into service. The items going into service include, but are not limited to: steam turbines, moisture separator reheaters, feedwater heaters, normal containment coolers, main generators, feedwater pumps, condensate pumps, large electric motors, and main power transformers –

which are required to produce the 367 MWe that the EPU project will be delivering to customers by year end.

Q. Are the 2012 actual/estimated costs presented in your testimony "separate and apart" from other nuclear plant expenditures?

A. Yes, the 2012 actual/estimated costs presented are "separate and apart" from other nuclear plant expenditures. The construction costs and associated carrying charges and recoverable O&M expenses for which FPL is requesting recovery through this proceeding were caused only by activities necessary for the EPU, and would not have been incurred otherwise. As explained in my testimony submitted in this docket on March 1, 2012, through engineering analyses FPL has identified the major components and systems that must be modified or replaced to safely uprate the units and only those modifications are included in the EPU project. FPL has continued to carefully follow all of the safeguards in this respect, which the Commission has previously reviewed and found to be reasonable and appropriate.

Q. Are FPL's actual/estimated 2012 EPU costs reasonable?

A. Yes. The majority of FPL's 2012 expenditures are for (i) payments to long lead equipment manufacturers; (ii) payments to the competitively bid EPC vendor and other vendors awarded some of the EPC scope; (iii) payments to original equipment manufacturers for LAR engineering analyses; and (iv) the implementation costs, including the planning, scheduling, and execution associated with four EPU outages.

Careful vendor oversight, continued use of sub-contracting and competitive bidding when appropriate, and the application of the robust internal schedule and cost controls and internal management processes all support a finding that FPL's actual/estimated 2012 expenditures are reasonable.

2013 PROJECTED CONSTRUCTION ACTIVITIES AND COSTS

Q. Please summarize the construction activities projected for 2013.

A. In 2013 FPL will complete the EPU project, including related project close-out tasks. The EPU LAR Engineering Analysis phase will have been completed and all LAR approvals will have been received. The Long Lead Equipment Procurement Phase will be completed, including receipt of equipment for the modifications in the 2012-2013 Turkey Point Unit 4 outage. FPL will complete execution of the Turkey Point Unit 4 EPU outage, including extensive testing and systematic turnover to operations. Exhibit TOJ-24, 2013 Extended Power Uprate Work Activities, includes a description of the work activities for this outage.

Q. Please describe how FPL developed its projections of 2013 costs for its NFRs.

A. The 2013 projected costs were developed from Project Controls forecasts as described above.

Q. What types of costs does FPL project to incur for the Uprate project in 2013?

A. As indicated in Exhibit TOJ-14, Schedule Projection (P) – 4 and P-6, and summarized in Exhibit TOJ-25, EPU Projected 2013 Summary Costs Tables, Tables 1 through 9, costs will be incurred in the following categories: Engineering & Design; Project Management; Power Block Engineering, Procurement, etc.; EPU Recoverable O&M; and Transmission Capital and Recoverable O&M. Table 1 is a summary of each of the categories showing the 2013 projected amounts. The amounts shown in the exhibit are slightly different than the NFR schedules as footnoted on the exhibit.

Q. Please describe the activities in the License Application category for 2013.

A. For the period ending December 31, 2013, License Application costs are projected to be $0 as shown on Table 2 of Exhibit TOJ-25.

Q. Please describe the activities in the Engineering and Design category.

A. For the period ending December 31, 2013, Engineering and Design costs are projected to be $5,942,487 as shown on Table 3 of Exhibit TOJ-25. The amount consists primarily of FPL engineering activities to support implementation of the engineered modification packages.

Q. Please describe the activities in the Permitting category for 2013.

A. For the period ending December 31, 2013, Permitting costs are projected to be $0 as shown on Table 4 of Exhibit TOJ-25.

Q. Please describe the activities in the Project Management category and how those activities help to ensure that the Uprate project will be completed on a reasonable schedule and at a reasonable cost.

A. For the period ending December 31, 2013, Project Management costs are projected to be $15,793,184 as shown on Table 3 of Exhibit TOJ-25. This category includes the project management costs associated with the oversight and management of the implementation of modifications during the planned Turkey Point Unit 4 outage scheduled to complete in early 2013. This work and the associated costs are required to ensure the Uprate project is managed in a safe, efficient, and cost-effective manner.

Q. Please describe the 2013 activities in the Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2013, Power Block Engineering and Procurement costs are projected to be $174,421,527, as shown on Table 6 of Exhibit TOJ-25. This amount consists of final milestone payments to be made to manufacturers of long lead materials and payments to be made to the EPC and other vendors for the work associated with the implementation of the engineered modification packages in the Turkey Point Unit 4 planned 2013 outage. This includes final known payments to vendors following installation and testing of the equipment supplied for the Uprates completed through 2013.

The Turkey Point Unit 4 outage that will be completed in 2013 is the final EPU outage. It will add approximately 123 MWe for the benefit of FPL customers. Some of the modifications planned are: main turbine upgrades, main generator rewind and rotor replacement, moisture separator reheater replacements, main condenser replacement, condensate pump and motor replacements, feedwater heater replacements, and the feedwater heater drain piping replacement. This outage is scheduled to be completed early in 2013 followed by project closeout.

Q. Please describe the activities in the Non-Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2013, Non-Power Block Engineering costs are estimated to be $0 as shown on Table 7 of Exhibit TOJ-25.

Q. Please describe the 2013 projected recoverable O&M costs.

A. Projected recoverable O&M costs for the EPU project in 2013 total $5,167,618 as shown on Table 8 of Exhibit TOJ-25. Recoverable O&M primarily consists of costs for performing equipment inspections and an estimate of obsolete materials that will be expensed as a result of modifications and project closeout. Additionally, required EPU activities that do not meet FPL's capitalization policy are included.

Q. Please describe the 2013 activities in the Transmission category.

A. For the period ending December 31, 2013, Transmission costs are projected to be $250,000 as shown on Table 9 of Exhibit TOJ-25.

Q. Please describe the items going into service in 2013.

A. Exhibit TOJ-24, Extended Power Uprate Project Work Activities for 2013, is a listing of equipment and control devices that are planned for installation and are planned to be placed into service in 2013. This list includes the main generator rotors, high pressure turbine rotors, main transformers and cooler modifications, feedwater heaters, condensate pumps, and main condensers, among others.

Q. **Are the 2013 cost projections presented in your testimony "separate and apart" from other nuclear plant expenditures?**

A. Yes. The 2013 cost projections presented are "separate and apart" from other nuclear plant expenditures. As explained earlier in my testimony, FPL's identification of the major components that must be modified or replaced to enable the units to function properly and reliably in the uprated condition is based on engineering analyses.

Q. **Are FPL's projected 2013 EPU costs reasonable?**

A. Yes. FPL's projected 2013 costs reflect the remaining implementation work that is planned to occur in that year, the large number of systems going into service, and project closeout costs. Project staffing levels, including vendor staffing, will be adjusted to support the modification package engineering design, implementation, outage support and project closeout. The majority of FPL's costs will reflect final payments on contracts introduced and reviewed in prior proceedings. Continued careful vendor oversight as the project reaches conclusion and the application of the robust internal schedule and cost controls and internal management processes, all demonstrate that FPL's projected 2013 expenditures are reasonable.

Q. **Please list the exhibits attached to this testimony.**

A. I am sponsoring or co-sponsoring the following exhibits:

- Exhibit TOJ-14 consists of 2012 AE Schedules, 2013 P Schedules, and 2013 TOR Schedules. These Nuclear Filing Requirement (NFR) Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and me, respectively.
- TOJ-15, 2012 EPU Project Benefits at a Glance
- TOJ-16, EPU Florida Workforce Summary
- TOJ-17, Extended Power Uprate Project Schedule as of April 23, 2012
- TOJ-18, Examples of Design, Implementation and Construction Complexity
- TOJ-19, St. Lucie Unit 2 2012 EPU Scope
- TOJ-20, Turkey Point Unit 3 2012 EPU Scope
- TOJ-21, Turkey Point Unit 3 2012 EPU Outage Construction Work
- TOJ-22, 2012 EPU Project Work Activities
- TOJ-23, EPU Actual/Estimated 2012 Summary Cost Tables
- TOJ-24, 2013 EPU Project Work Activities
- TOJ-25, EPU Projected 2013 Summary Cost Tables

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF TERRY O. JONES

DOCKET NO. 120009-EI

AUGUST 1, 2012

Q. **Please state your name and business address.**

My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed with Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprates.

Q. **Have you previously filed testimony in this docket?**

A. Yes. This is a supplement to my previously-filed testimony.

Q. **What is the purpose of this supplement to your testimony?**

A. This supplement provides the Florida Public Service Commission (Commission), Commission Staff, and all parties to this docket with an update on three matters occurring after the filing of my July 9 rebuttal testimony: (i) FPL has negotiated an agreement with Siemens related to FPL's costs for the St. Lucie Unit 2 stator core repair work incurred in 2011; (ii) FPL has completed and placed into service St. Lucie Unit 1 in uprate condition with excellent results; and (iii) FPL has completed several internal audits previously in process.

Q. **Are you sponsoring any supplemental exhibits to this testimony?**

A. Yes. I am sponsoring the following exhibits, which are attached to my supplemental testimony:

- TOJ-28, Confidential Agreement
- TOJ-29, St. Lucie Unit 1 LAR Approval.

Q. Please provide the update related to FPL's costs for the St. Lucie Unit 2 repair work incurred in 2011.

A. Negotiations with Siemens that were in process at the time the Commission Audit Staff issued their report on June 19, 2012, have since been concluded. FPL and Siemens reached a commercial resolution which FPL believes should satisfactorily address considerations raised by the Audit Staff in their report. The specific terms of the resolution are contained in Exhibit TOJ-28, which is the confidential agreement FPL recently entered into with Siemens. This will reduce the cost of the EPU project by substantially more than the repair costs FPL incurred. FPL maintains its position that it prudently managed the generator activities.

Q. Please describe the completion of the St. Lucie Unit 1 EPU.

A. A short outage was completed on July 25, 2012, to complete implementation of the St. Lucie Unit 1 EPU. At the date of this supplemental testimony, the unit is operating at full uprated power. The EPU work increased the capacity of St. Lucie Unit 1 by approximately 144 megawatts – which is about 12 percent more megawatts than FPL's early 2012 estimate of approximately 129 megawatts used in FPL's 2012 feasibility analysis. The official increase in power will be determined after performance testing in late August. The final implementation work was performed after the Nuclear Regulatory Commission (NRC) approved FPL's License Amendment Request (LAR) for the St.

Lucie Unit 1 EPU on July 9, 2012. The NRC's cover letter transmitting the St. Lucie Unit 1 EPU LAR approval is attached as Exhibit TOJ-29.

Q. Based on the performance of the first unit, is FPL expecting similar results on the remaining three units?

Yes. In total, the EPU project is likely to add approximately 522 to 532 megawatts, as compared to the 490 megawatts previously estimated. The final Turkey Point Unit 3 EPU outage is almost complete and FPL expects approximately 125.5-130.5 megawatts. FPL expects St. Lucie Unit 2 to provide approximately 127 megawatts, which is 12 megawatts more than previously estimated, upon completion of the EPU outage that begins August 5, 2012. The final Turkey Point Unit 4 EPU outage scheduled to begin in November 2012 is also expected to produce approximately 125.5-130.5 megawatts.

Q. Please provide the update on internal audit activities.

A. The Commission Audit Staff's June 19, 2012 report listed complete and pending EPU internal and external audits and investigations for 2012. Since that time, three of the previously pending audits or investigations have been completed. The EPC Contract Audit conducted by Experis had [redacted]. The [redacted] investigation conducted by Internal Audit [redacted]. The [redacted] investigation [redacted] by the Company. Ineligible costs, if any, would be corrected in the 2013 Nuclear Cost Recovery filing.

Q. Does that complete the supplement to your testimony?

A. Yes.

BY MR. ANDERSON:

Q Mr. Jones, do you have a summary of your testimony?

A Yes, I do.

Q Please provide it to the Commissioners.

A Thank you. Good morning, Commissioner Brisé and Commissioners.

FPL is safely and cost-effectively implementing the extended power uprate project at our Florida nuclear units. This is a complex project in its final phase with great benefits for FPL's customers and for Florida for decades to come.

The project provides the equivalent output of half of a new nuclear plant in about half the time and at significantly less than the estimated cost per kilowatt installed of a new nuclear plant. That's a strong value proposition.

The project is expected to save our customers about $3.8 billion in fuel costs over the life of the units, not including the benefits from the additional output. We now expect 522 to 532 megawatts. This is an increase of 133 megawatts, or 33% more than estimated at the beginning of the project.

This project will contribute substantially to electric grid reliability by producing power where it's needed most in southeast Florida.

Commissioners, I'm pleased to report the following progress. The Nuclear Regulatory Commission has approved all but one EPU license amendment. All design engineering is complete for the fourth and final reactor. St. Lucie Unit 1 and Turkey Point Unit 3 uprates are complete, and Unit 3 is in power ascension. This adds a total of approximately 305 megawatts.

The St. Lucie Unit 2 uprate outage is underway and is planned to complete in November, adding 127 megawatts, to bring the total year-end increase to approximately 400 megawatts by December this year.

The final Turkey Point Unit 4 uprate outage is on schedule to begin in November, and when completed in early 2013, the total EPU output will be approximately 530 megawatts.

It has and it remains a big job. On average, 3,400 people are working in our Florida sites every day this year. Over the life of the project we will employ about 21 million manhours of work, or to put it another way, that's 10,000 manhours of -- 10,000 man years of work in just four and a half years.

The nonbinding cost estimate range developed earlier this year, 2.95 to 3.15 billion, and this year's feasibility analysis once again shows that completing the project is solidly cost-effective for our customers. As I have stated before, this range is subject to change, especially as we incorporate our lessons learned from the recently completed Unit 3 construction effort and finalize our plan for our fourth and final reactor. I expect to complete that effort by the end of October, and I expect that the installed cost per kilowatt upon completion will be about the same as was forecast in this year's feasibility filing.

The costs incurred in 2011 and 2012 and those projected for the remainder of 2012 and 2013 are both prudent and reasonable. FPL's investment in additional nuclear generation approved by this Commission has created hundreds of carbon free megawatts that reduce our dependence on foreign oil, natural gas, and other fossil fuels, while creating thousands of jobs and will continue to provide fuel cost savings for FPL customers for decades to come.

I want to take just a moment to highlight a couple of things on these charts. On this chart here, this demonstrates the sheer complexity from a human capital perspective of what it takes to execute a project of this complexity. These two bar charts on, on the far left represent about 1,640 workers at our

Florida sites in the year 2011, and then ramps up to 3,400 in 2012.

These two charts here demonstrate the difference in complexity between the St. Lucie and the Turkey Point site, which this, this graphic is for St. Lucie and this graphic is for Turkey Point, and the blue labels are the ones that denote the components or the systems that we modified to get the increased energy output.

Thank you. That concludes my summary.

MR. ANDERSON: Mr. Jones is available for cross-examination.

CHAIRMAN BRISÉ: All right. It is 11:52. Rather than start cross-examination and stop in eight minutes or so, we're going to go ahead and break for lunch at this time, and we will reconvene at 1:00. Okay?

(Recess taken.)

Okay. We will reconvene at this time. I think the, FPL had tendered the witness for cross, and we were about to begin.

Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Jones, you are sponsoring your March testimony and your April testimony at this point; correct?

A That's correct.

Q My questions may require you to bounce from one to the other a couple of times, but that's only fair because I'll be doing the same thing.

The first question relates to your March testimony, page 45, lines 14 and 15.

A Page 45, which lines?

Q Lines 14 and 15. You say there that despite FPL's continuing efforts to proactively manage the adverse impact from the two natural disasters that you discuss above and subsequent NRC response, we expect that the negative project cost impacts will unfortunately carry over into 2012.

Are those expectations built into the revised estimate that you and Dr. Sim address in testimony?

A Yes.

Q Now turn to your April testimony. The first reference is page 8.

A I'm there.

Q You say that last year 36% of the EPU engineering had been completed and it's now up to 90%; correct?

A Referring to line 12 and 13, yes, that, that's correct. 36% of the engineering based on total hours, and, as of the date of this filing, 90% based on total hours, not as a percentage of design packages complete.

Q And you also say in your testimony that modification packages must be, must reach 90% before detailed construction planning can commence, do you not?

A That's correct.

Q Was that something that, which you, of which you were aware last year, in the last August hearing cycle?

A Yes, that's correct. I've been clear going all the way back to 2010 that when you have a conceptual design, that you can do some preliminary work based on that design, even some work at risk. But if you visualize a very simple drawing, you know, like a breaker panel to a pump or a light switch, that's a conceptual design. A 90% design package would actually have detailed design drawings, for which you could start to do pickoffs for commodities, conduit, steel.

Q And if you'll turn to page 17.

A 17 in the April?

Q Yes. I'm still in April.

A I'm there.

Q At the bottom of 16 and top of 17 you discuss some of the tasks that are involved. And, among other things, you say it's necessary to quantify how much of different commodities such of feet of wire, feet of piping, and consumables will be required, as well as plant structural modifications to support the EPU modifications, do you not?

A That's correct. As the designs become final and you start to have detailed, what I call isometric drawings, like, you know, the breaker could be located five seismic rooms over from where the load is, and you lay out all those conduit runs, that's when you start to be able to get into the detailed planning on what the actual mod -- structural changes that you'll have to make in the plant to be able to complete the modification to the system.

Q And this statement does not present something that was not known last year, does it? This is something of which you were aware last year?

A Yes. Yes. Again, as I've described in 2010 and '11 and again this year, as you complete each major milestone, you're very much better informed about what the capital, human capital is necessary to be able to accomplish the actual construction effort.

It's no different than if you look at a simple electrical drawing for your house. It would have a breaker box, it would have one breaker, and it would show a wire going to your refrigerator. Well, if your refrigerator is in a basement, that's an entirely different run.

MR. McGLOTHLIN: Mr. Chairman, I believe this goes far beyond anything necessary to answer my question.

CHAIRMAN BRISÉ: I would agree.

BY MR. McGLOTHLIN:

Q Mr. Jones, look at page 18, lines 7 and 8.

A I'm there.

Q And on page 18 you describe how Bechtel provided a target cost estimate in November of 2011; correct?

A No. Actually Bechtel provided an estimated completion at our request for the intended purpose to attempt to establish a target price for Turkey Point.

Q All right. Thank you for that clarification. You say this is Bechtel's first opportunity to provide an estimate that included detailed construction costs; correct?

A For the balance of the design work, yes, that's correct.

Q And this first opportunity occurred after last August's hearing cycle; correct?

A Yes. For the estimated completion for the to go work, that is correct.

Q Is it true that FP&L engaged High Bridge Associates to assist FPL in 2010?

A Yes. We contracted High Bridge to assist us to establish a bottoms up estimate for Turkey Point Unit 3.

Q And as I understand it, the intent was to have the services of High Bridge estimating expertise when you were negotiating with Bechtel with respect to the overall costs; correct?

A Yes. As I previously testified in '10 and '11, the purpose of hiring High Bridge was to help in negotiation and better gain understanding and insights into the construction costs associated with Unit 3.

Q If you'll turn to your March testimony one more time, page 34.

A I'm there.

Q You'll see at page 34, lines 2 through 5, your statement that High Bridge was retained by Bechtel at FPL's request to perform craft implementation estimating services for this effort. Do you see that?

A I see that, yes. May I explain that?

Q Well, we'll get to that.

My question is, can you clarify for whom High Bridge was working at this point if at first they were engaged to assist FPL in negotiating with Bechtel and subsequently were hired by Bechtel at FPL's request?

A Yes, I'd love to explain that. In December 2009, we contracted, we contracted with High Bridge to come in and do a bottoms up estimate for Unit 3. They completed that work and provided that information final in June of 2010. We used that in our, our negotiations, in our oversight of Bechtel for the near-term work on Unit 3. That's where that product had the highest value.

Fast-forwarding through 2010 through, to the end of 2011, the engineering had progressed quite a bit. And at that point we wanted to try and get to a target price for Turkey Point, and one of the ways to get to that target price is to get Bechtel to agree on what, what they would agree to as far as an all in finish the construction for Turkey Point.

Given that we had moved well beyond where we were with High Bridge from, based on the engineering that was done in 2009, because -- is we requested that Bechtel contract High Bridge because High Bridge was already up to speed and would not be starting over or from ground zero and was already familiar with the project. So Bechtel contracted High Bridge to come in, and we wanted them to focus on the construction and the labor, direct craft and indirect craft, for the physical construction part of the modification.

Q Do I understand correctly that the portion of the work that FPL wanted High Bridge to do, which was craft implementation estimating services, was a substantial component of the overall estimating work?

A That's correct.

MR. McGLOTHLIN: Those are all my questions.

CHAIRMAN BRISÉ: All right.

FIPUG.

MR. MOYLE: Thank you. Thank you, Mr. Chairman. We have questions.

CROSS EXAMINATION

BY MR. MOYLE:

Q Mr. Jones, as part of your testimony, are you here asking this Commission to make an award of dollars to Florida Power & Light related to your activities in the uprate project?

A Yes. We are seeking from this Commission to issue a ruling of prudency and reasonableness for our costs incurred and the amount, dollars to be specific would be 151 million for EPU and new nuclear combined with EPU, representing about 90% of that, and that's for 2013.

Q So out of all of the, the monies that are being sought, 90%, approximately, is for the EPU work?

A That is correct.

Q And am I correct that you expect all of this EPU work to be finished in 2013?

A Yes, that is correct. The majority of the work is going to be complete by November. The fourth and final unit will be complete early 2013.

Q So given that, we won't expect, you know, to see a 2014 projected expense filing next year; correct?

A I don't think that's correct. I think there are some inspections in the follow on (phonetic) outage that are minor in comparison. They're inspections, not construction type activities that follow on in 2014.

Q And in your, your role over these projects, you have responsibility for both of these projects, correct, the St. Lucie and the Turkey Point EPU projects?

A I have responsibility for the EPU project, which involves four reactors, St. Lucie and Turkey Point.

Q Okay. And so when you describe the EPU project, you don't segregate them? You, you describe it as an EPU project that consists of four reactors at two power plant sites?

A Yes. I think the simple way to look at it is we were commissioned by this Commission to establish greater than 400 megawatts of a power base in southeast Florida that was carbon free. So if you, if you consider that, Commissioners, as a table, a power base table that has four legs, four reactors --

MR. MOYLE: Mr. Chairman, I think I got -- I think he answered the question.

BY MR. MOYLE:

Q So those slides that you had up there, I guess you took them down, the big billboards, or not billboards but the sheets -- do you have the hand, the handouts that were provided that showed St. Lucie versus Turkey Point?

A Yes, I do.

Q Okay. And there's a lot going on on both of these handouts. You would agree with that; correct?

A Yes, I would agree with that.

Q And I think in your opening statement you said that there's a, there's a difference in complexity between Turkey Point and St. Lucie; is that correct?

A Yes, that is correct, and that is not new. We've said that since the beginning of the project.

Q Okay. So, you know, the engineering work that you're having done, it's not like you can get one set of engineering plans and say, great, we got one set of plans that applies to all four units. That would not be correct, the correct assumption; correct?

A Not on an -- that is correct, not on an individual mod by mod basis. There's some common engineering activities for the sites.

Q Okay. And for your accounting purposes, isn't it true that you look at the St. Lucie costs and account for St. Lucie costs different from your Turkey Point costs?

A Yes, that --

Q Yes or no would be fine.

A Yes, that is correct. We break it all the way down to a component, valve, wire level.

Q Okay. Let me refer you to page 39, line 12.

A Which, which filing?

Q This is your, your first, your first filing.

A April?

Q March.

A March. I'm sorry. I missed the page.

Q Yeah. 39. This is -- I'm sorry. Your March 1, 2012, filing, page 39.

A I'm there.

Q Line 12. And you were asked the question: Have the 2011 earthquake and tsunami in Japan or the 2011 earthquake in Virginia and resulting effects of the nuclear power -- effects on the nuclear power plants there affected the EPU project?

And would you just read the first sentence of your answer out loud.

A Starting with line 12: Yes, these two natural events have adversely impacted the NRC staff resources and delayed the review and approval of the FPL EPU LARs.

Q And then also down on line 19 you say, and I'll read it, quote, Despite our continuing efforts to manage the adverse impact, the two natural disasters and subsequent NRC response had significant costs and schedule impacts on the project that unfortunately will carry over into 2012.

So am I reading your testimony correctly that, that you attribute a significant portion of the cost overruns to the seismic event that occurred in Virginia and the seismic event that occurred in Japan?

A No, that's incorrect. That's taken out of context. I, I attribute the additional cost associated with the project to regulatory and safety margin, design evolution, implementation, and constructability. Specific to license amendment requests and engineering LAR analysis, those two natural disasters did have a significant impact. The primary resources that we were engaged with with the NRC was diverted to respond to those events, and that subsequently delayed the LARs and subsequently caused us to change the outage schedule.

Q So if I understand your answer, you -- it's the, it's the Nuclear Regulatory Commission, I mean, they didn't have enough staff to kind of keep up. Is that in essence your testimony?

A My --

Q Yes or no.

A No, that is not correct. What I said was the primary reviewers, those that were directly engaged in this very highly technical engineering base review, were diverted to deal with those natural disasters, and that delayed the review and approval by the NRC, which caused us to have to change our outage schedule, which has a significant cost impact on the project.

Q Okay. And you were here earlier in the, in the day when Mr. Scroggs indicated that there was a shift in Nuclear Regulatory Commission review for Turkey Point 6 and 7, the new nuclear that didn't result in any cost increase; correct?

A I wasn't present during his testimony.

Q Do you believe that every delay from the NRC results in an increased cost?

A Oh, it absolutely does, because the engineers that you have on staff to resolve the issues and concerns that the NRC is going to raise, the clarifications they need to complete their detailed technical review to write their safety evaluation, that has costs associated with it.

And at the point that it actually causes the LAR approval schedule to change, it actually causes you to shift your outage start date, which has a significant impact on the cost as well.

Q So were you here at the start of the hearing?

A Yes, I was.

Q Okay. And OPC, in their, in their opening, referenced an increase as it related to the uprate project for Turkey Point of over $500 million on projected expenditures. Do you question their math?

A Their number is not quite correct, but over $500 million is correct. It's about $530 million.

Q And that's a year over year increase?

A That was a year over year increase for the reasons I stated earlier, for the regulatory safety margin, design evolution, and implementation and constructability. What he failed to mention was the 19% increase in the megawatts.

Q Well, you got that in.

A Thanks.

Q And, and, and that's caused not because of any engineering improvements, that's just caused because you guys looked at it and said, you know, I think we have less in-house load on the system; therefore, we have more megawatts that we can generate. Isn't that essentially correct?

A No, that's not essentially correct. It's a combination of, of, as we specified the, as the -- for our specifications for the material, and as we were able to achieve those specifications per the assembled components, and, yes, a portion of it was refined engineering estimates on reduction in-house loads. By purchasing efficient motors, for example, we were able to improve the megawatts generated by this project. I think the team has done just an amazing job.

Q So let me, let me refer you to a couple of other places in your testimony. Page 32, line 16. Your question you were asked about the management of the EPC vendor and the progress and modification engineering made in 2011. The EPC vendor is Bechtel; right?

A Yes, the EPC vendor is Bechtel.

Q And on line 16, you suggest that the work was taking longer than anticipated; is that correct?

A Yes. That's a direct result of the complexity of the project.

Q And Bechtel knew this was a complex project and you knew this was a complex project going in; right?

A That's correct. That's the reason for the framework for the nonbinding cost estimate.

Q Right. Right. But it wasn't like all of the sudden, oh, my goodness, we're in a complex project. I mean, everybody went in eyes wide open to the level of complexity with these uprate projects; correct?

A That's correct. And that's why as you complete the engineering and you get your detailed drawings, you're able to refine your estimate going forward.

Q All right. So I want to ask you, you, it looks like on line 18 that you directed Bechtel to subcontract some of the engineering design work to, to third parties; is that right?

A Yes, that is correct. And the reason that we did that --

Q And --

THE WITNESS: May I answer the question, Commissioner?

CHAIRMAN BRISÉ: Excuse me, sir?

THE WITNESS: May I finish answering the question, why we did that?

CHAIRMAN BRISÉ: Yes, you may.

THE WITNESS: Thank you, sir.

We, we directed Bechtel to subcontract some of the engineering design work, because based on Bechtel's estimate on what it would take to complete it, it was going to take them longer and spend more money than if they brought in additional expertise and actually handed it off. So, therefore, the overall cost is less. It's a cost avoidance measure. Thank you.

BY MR. MOYLE:

Q Did, did Bechtel know that you were going to direct some of the work to be done by a third party when they entered into the EPC contract?

A Yes. They understood that, that we reserved the right contractually to reassign work in the best interest of the project and our customers.

Q Okay. That's not my question. I understand you may have that contractual right. But was it contemplated that some of the engineering work that was in the scope of the EPC would be farmed out to third parties? Did you guys tell them when, you know, the deal was put together, Bechtel, you have a great engineering package, but, however, we're going to sub some of this work out to a third party?

I mean, that wasn't, that wasn't the sequence. I mean, you subbed it out because they were falling behind; right?

A No, that's not true.

Q They weren't, they weren't falling behind?

A No. There was, there was engineering scope of work that was never in Bechtel's scope that was in, in Shaw's scope from the very beginning. And we were up-front and honest with Bechtel from, from day one, that anywhere we, where we considered someone was what we called putting a better athlete on the field, we would do that. In fact, Bechtel fully supports that.

Q And, and so when you say in your testimony that you've affirmed and sworn to today that, that preparation continued to take longer than anticipated in 2011, are you, are you suggesting that there was not a delay in getting the engineering work done?

A No, I'm not suggesting there was a delay in getting the engineering work done. I'm saying as a result of the design evolution the engineering takes longer. Engineering is a science, not an art, and it takes what it takes to complete the calculations, and it's an iterative process.

Q So who, who did the subcontract work after Bechtel, after you exercised your contractual right to sub some of it out?

A Some of it was done by Shaw, some of it was done by Zachry. Those were the two major contributors.

Q So now instead of having one contractor, you have three that are all doing engineering work?

A No, they're doing it under the direction of Bechtel. Bechtel is accountable for their project.

Q And you would agree that that resulted in increased coordination that had to be done. You know, if you had one engineering firm, everybody under the Bechtel roof, and now all of the sudden Shaw and Zachry come in, that that, that does require some extra coordination; correct?

A Yes, it requires extra coordination on Bechtel's part. And to be transparent, if I bring in engineering and I have it self-performed, then that requires extra coordination on my part.

Q Did you have oversight responsibilities for Shaw and Zachry?

A There are some parts of the engineering that we self-performed and had Shaw or Zachry or others perform it for us. Typically document, what I would refer to as document only, which does not typically result in construction modifications, but analysis to support construction.

Q So let me take you to page 34, same date of your testimony, the December 1. On page 34, line 19, the lead-in question is: What does FPL's due diligence include? And you say that, on line 19, FPL also engaged other major suppliers to provide alternative proposals for certain portions of Bechtel's scope of work.

A That's correct.

And, Commissioners, this is in reference to the estimated completion that we asked Bechtel to perform. This was us doing our due diligence to make sure that the numbers provided by Bechtel weren't overly conservative.

Q So, so you made this request to in effect check their price; is that right?

A It goes beyond just checking their price. It also goes to the credibility of whether or not their plan is feasible. Because if their plan is not feasible, then they won't be able to accomplish it and it will result in a cost overrun.

Q Had you already signed the EPC contract with Bechtel at the point in time that you sought these alternative proposals?

A Yes. And we continue to this day to seek alternative proposals to scopes of work that Bechtel has. So, again, so we put the best athlete on the field during the construction phase.

Q To use your athlete analogy, do you, do you think the Denver Broncos are looking around for a new quarterback to replace Peyton Manning today?

A If I were them, I would be. Otherwise they're, otherwise they're just thinking short-term. We can't afford to do that in this business.

Q Well, for the record, he had a pretty good game the other night and won.

A That's one game.

Q But the, the point I want to understand is, while you already have an EPC contract inked with Bechtel, you've selected them to go forward, at the same time you're seeking alternate proposals for certain portions of, of, of Bechtel's work.

Did you randomly select certain portions of Bechtel's work, or did you say, you know, we think Bechtel is throwing some incomplete passes over here or not doing certain things in certain scopes of the work, and you looked for alternative proposals to scope of works that they, that you thought might have been done better?

A We have -- yes. We have detailed metrics on every scope of work that Bechtel or anyone else is doing on our site and we scrutinize those metrics. And if we see an opportunity for someone else that we think might be able to perform it a little bit more efficient because they have a, a greater level of expertise, we have two alternatives that we pursue. We'd ask Bechtel to consider bringing in a subcontractor, if it would ultimately save us more money at the end of the day, or we may have a specialty vendor such as Weltech or Custom Mark or PCI come in and actually perform that scope of work as either a self-perform to us.

And Bechtel, obviously we do -- we're, we're totally transparent with Bechtel, and, and not that I need Bechtel's permission to do it, because I don't contractually, but I get their buy-in because you don't want to complicate their work.

Q So I take it from the discussions and the, you know, your point earlier about there being a slowdown, that you -- excuse me -- that you had a level of dissatisfaction in certain respects with respect to, to Bechtel. Is that, is that a fair statement?

A Well, I'm FPL and I'm dissatisfied with all vendors and contractors in general. I'm never satisfied with their performance. I'm never satisfied with my own performance. We can always improve.

But to characterize Bechtel as generally dissatisfied, that is absolutely not correct. Bechtel is, is a world-class EPC, they do major projects around the world, and, and they're doing a very good job on a very complex project. Can they improve? Absolutely.

Can I improve? Absolutely.

Q And as you sit here today, the testimony, you haven't gotten everything right in the EPC -- I mean, EPU projects; correct? I mean, you could have done some things better, you could have improved. I think, I think you just made that statement.

A That's correct. We strive for excellence.

Q And are you suggesting that every, every dollar of the 151 million that you're seeking, that notwithstanding some of these issues that we've talked about, that, you know, every dollar was something that had to be spent?

A Yes. As Mr. Reed testified, it's not the cost that's prudent, it's the decisions we made and the expending of those dollars. And we were very prudent in our decisions and reasonable in our, in our costs.

Q And you think that includes, in addition to Bechtel, bringing in Shaw and Zachry and doing your own engineering?

A That's correct, because it resulted in either cost avoidance or actual cost savings to our customers. We actually, as a result of that due diligence that you mentioned, reduced the Bechtel estimated completion by $89 million.

MR. MOYLE: Mr. Chairman, I -- if he could answer my questions yes or no, I think it would move it along a little bit.

CHAIRMAN BRISÉ: Yes. Mr. Jones, if you could do a better job of being more precise with your answers.

THE WITNESS: Yes, Mr. Chairman.

BY MR. MOYLE:

Q Okay. I have a few further questions about specific portions of your testimony.

And I don't know if it's necessary to refer to it. If it is, tell me and I'll refer you to it. But, but generally you had two EPU projects, one at St. Lucie and one at Turkey Point. And you have currently only the output from St. Lucie 2, isn't that correct, that's generating electricity?

A No, that's not correct. We have one integrated EPU project and we have megawatts output from both St. Lucie and Turkey Point. Turkey Point Unit 3 is in power ascension.

Q Okay. So on, on page 13, line 19, you state: The successful completion of two EPU outages, one at Turkey Point 4 and the other at St. Lucie Unit 2, resulting in increased electrical output from St. Lucie Unit 2 of 31 megawatts, so it's already benefiting FPL customers. Is that your testimony?

A That's my testimony for 2011.

Q Okay. And, and for 2011 you say that you successfully completed two of the outages; right?

A That's correct. That was St. Lucie Unit 2 and Turkey Point Unit 4.

Q Okay. But in 2011 only one of them comes online and produces megawatts.

A That's right. The -- we try and do, we try and do the EPU execution in two outages. So you do a portion of the modifications and one outage, and then you do the balance of the modifications that are going to deliver the remainder of the megawatts. We saw an opportunity on St. Lucie Unit 2 to replace the LP turbines and get the megawatts online sooner. We're not replacing the low pressure turbines at Turkey Point, so that opportunity wasn't there for Unit 4.

Q The FPL executive steering committee, they're involved in the oversight of this project; is that right?

A That's correct.

Q Okay. Who's on that committee?

A Our president and CEO, our senior executive and chief nuclear officer, our senior vice president of engineering and construction, our vice president of integrated supply chain, regulatory affairs has a representative on there, the president and CEO of FPL.

I think that's about it.

Q And do you report to this committee; do you make presentations to them?

A Once a quarter I provide a presentation to the executive steering committee. That's correct.

Q And has the executive steering committee ever raised or voiced concerns about the progress of the EPU project?

A Yes. The executive steering committee does voice concerns about cost, the megawatts, first time quality. Exactly what you would, you would expect. We do focus on the areas that we can improve.

Q And, and related to costs, you made a comment about this project is 500 megawatts and is about half of the cost of a regular nuclear project; is that correct?

A No. I said half of a nuclear unit half the time and significantly less cost than a new nuclear unit.

Q Okay. Did you, did you do a similar comparison with respect to a new, new gas unit?

A Actually Dr. Sim will speak to the economic feasibility analysis that takes into account gas units, new nuclear, and any other alternative to EPU, and will show --

Q Okay. And that, that wasn't my question. I'm just asking, I mean, saying, did you, for your comparison, for your testimony about the cost savings relative to a new nuclear project, did you look at the cost of the EPU project relative to a new gas unit?

A To be clear, I don't do the analysis. Dr. Sim does the analysis, and he does all those comparisons.

Q Okay. So when you talk about the savings related to the nuclear project, the EPU, then that really is based on, on information that Dr. Sim provided?

A The analysis -- when you say savings, do you mean the cost savings to our customers?

Q Your testimony relative to the EPU uprate providing benefits at a -- I thought you indicated it was less expensive than new nuclear.

A That's correct. That analysis comes from Dr. Sim's group.

Q Okay. So you don't have firsthand knowledge of that, that information. That's a Dr. Sim question.

A No, I do have firsthand information, as that information is provided to me from Dr. Sim.

Q Okay. Has any information been provided to you relative to the cost of new natural gas units?

A Yes. That is in the economic analysis feasibility study.

Q How about with respect to providing 550 megawatts of natural gas; how does that compare to providing 550 megawatts of nuclear from the uprate project, if you know?

A I don't know that specific answer.

MR. MOYLE: If I could have just a minute.

CHAIRMAN BRISÉ: Sure.

BY MR. MOYLE:

Q On page 22, line 13, this is some questions about procurement processes and controls.

A Excuse me. Are we still in the March testimony?

Q Yes, sir.

A Page 22?

Q Right.

A Line 13?

Q That, that's where the question is. And I'll draw your attention to -- you make a statement in here that, that the standard approach for the procurement of materials or services with a value in excess of 25,000 is to use competitive bidding.

Do you know or do you have any information relative to the amount of the contracts that were awarded, what percentage was awarded pursuant to competitive bid as compared to sole source?

A In 2011, our -- subject to check, this is from my, my rough notes in anticipation of the question -- it was approximately, total contract amounts were approximately 456 million, with a total number of contract transactions of roughly 900. 68 of those 900 contract transactions, about 68 were sole, sole source justifications. I'll get that out in a second. They had a value of about $102 million of the 456.

Q So if we use -- if we look at a comparison based on dollar values, you would agree 102 is approximately two-thirds of 151 million?

A I don't understand that correlation.

Q I'm just trying to understand the amount of the dollar value out of the 151, how much of that was realized through sole source as compared to competitively bidding. And I thought you just answered by saying that the dollar value of the contracts was 100 million.

A No. I said 456 million.

Q Out of a total of what?

A The total contract amounts for 2011 were roughly 456 million. The SSJ's portion of that was roughly 102 million, or 22%.

Q Was that sole-sourced, the 102?

A Yes, that was sole-sourced.

Q And what, what, what service do they provide?

A That would be in the case of if we expanded scope, say, for Siemens, based on discovery you do additional work, you already have a contract and purchase order in place that has a cap on it, and so therefore you're not going to switch turbine vendors in the middle of the EPU project, and so you're going to have to process a sole source justification to give that expanded scope to Siemens.

Q But isn't it true, we just talked about it, you all are looking for the best athlete, you know, all the time. I mean, aren't you also wanting to make sure that things like this 102 million, that you're getting the best deal on that? Did you not look at possible other suppliers for, for what was represented by this 102 million?

A Yes, we absolutely do that as a part of the sole source justification when the expanded scope comes to light. In this case, say we determine we have to replace the bearings on the, on the turbine, Siemens is the OEM. When you do the sole source, you still have to compare Siemens to other people that can supply that resource. And that's part of your justification for they're already on the turbine deck, they already know the work, they're the OEM, and you don't want to bring in GE and mix machine parts on turbines. That's not good.

Q You list as a significant accomplishment that you were able to achieve a target price; is that right?

A Yes. That was a target price that was established for St. Lucie.

Q Okay. But, but you haven't been able to achieve a target price for Turkey Point; correct? Yes, no?

A That is correct. We did not establish a target price for Turkey Point.

Q Okay. And Turkey Point is the project that has the additional cost overruns of north of 500 million; correct?

A That's correct.

Commissioner, may I explain why we didn't establish a target price for Turkey Point?

MR. MOYLE: He can do that on redirect.

CHAIRMAN BRISÉ: Yeah. Redirect.

THE WITNESS: Okay.

BY MR. MOYLE:

Q With respect, with respect to a target price, what, what, what is a target price? Is that like a cap to say the vendor comes in and says we'll do it for X and we'll assume some risk, and, you know, it's just not just the time and materials that we submit? Can you indicate what -- is my understanding of a target price generally correct?

A No, that is incorrect.

Q What's a target price?

A What a target price is, that you snap a line on any given date. And based on the scope that you currently have, you negotiate a price to perform that, that scope of work and only that scope of work. Any discoveries or additional complexity are subject to target price adjustments. And you're, you're still on a, on a T&M scale, so that puts you -- while that does bring some certainty to the cost for that defined scope of work that you can agree on, what it does is it now kicks off a mechanism where you're in this constant debate with the EPC or any other supplier, what was in scope and what was not in scope. Because you get, you get pretty granular, pretty much in the bug dust on those things.

Q In your view that's a good thing?

A Establishing a target price is a, is generally a good thing.

Q Why?

A The reason is, is that at least for a portion of the work you have some agreement between yourself and the supplier and a certain expectation of what they're going to accomplish that work for that you can hold them accountable for. There, there are incentives for beating the target price, and there's also some penalties for exceeding the target price, if you can agree that there truly was no scope change or something not known or understood that the EPC should have known when they gave you that, that target price. So it's good from that standpoint.

But I will tell you that we no longer have the target price in effect at St. Lucie.

Q And so the, I guess the final question that I have for you is, as we sit here today, with the, the 500 million plus cost overruns on the Turkey Point uprate project, am I understanding the position, your position and the position of the company, that FPL has no responsibility for any of those cost overruns that, that this Commission should look at and say, you know, that probably wasn't the best decision?

MR. ANDERSON: I'm just going to object to form. The subject matter is fine, but counsel keeps saying the words "cost overrun," "cost overrun." What these are is changes in the nonbinding cost estimate. That's clear throughout the testimony.

CHAIRMAN BRISÉ: Mr. Moyle?

MR. MOYLE: With that clarification, if he could answer the question, that would be fine.

CHAIRMAN BRISÉ: Sure.

THE WITNESS: Yes. Thank you.

We absolutely are accountable for the execution of this, this project, and, and we are delivering on this project. And I happen to agree with Mr. Anderson. They're not cost overruns. They're costs directly attributed to the increase in scope.

BY MR. MOYLE:

Q Okay. And, and I don't think you answered my question, which was with respect to those level of cost projected increases, as Mr. Anderson referred to them, am I correct that, that FPL is not taking any responsibility or, you know, blame for that, that it's being put on natural disasters, you know, EPC contractors maybe not doing the things in a timely fashion that FPL takes no responsibility for any of those increases?

If you could just answer yes or no, that would be helpful.

A That's totally incorrect.

Q So I think that would be a no?

A No.

Q Okay.

A No in that we do take complete responsibility for this project. I want to make sure you guys understand my no.

Q I didn't.

So while you take responsibility for the project, as it relates to the cost overruns, none of those cost overruns were your, were your fault. Is that, is that what I understand essentially the testimony --

MR. ANDERSON: Let's try that again.

THE WITNESS: First off, you're mischaracterizing. They're not cost overruns.

MR. ANDERSON: We object. Can we get our record straight?

CHAIRMAN BRISÉ: Sure. Sure.

I guess the same objection stands with respect to the use of the term "overruns."

THE WITNESS: The additional cost that is associated with the scope --

MR. MOYLE: Can we, can we --

CHAIRMAN BRISÉ: Mr. Jones, if you could --

MR. ANDERSON: Let him ask a new question.

MR. MOYLE: Mr. Anderson, what would you prefer that I call them, projected cost overruns?

MR. ANDERSON: These are cost -- it's a nonbinding cost estimate is what we provide each year, and what we're describing is a change in the nonbinding cost estimate. That's how the statute and rule work and how the project is administered.

MR. MOYLE: How about if I call them projected nonbinding cost overruns?

MR. ANDERSON: Not so much. They're really -- you could call them changes in nonbinding cost estimate, increase in nonbinding cost estimate. Those, those are both right.

BY MR. MOYLE:

Q All right. So to get back to what I hope, I hoped would be my last question, would, would be to pose it this way, which I think will call for, you know, a yes, no, which is, am I understanding that, while FPL takes responsibility for the execution of this project as it relates to the more than $500 million in a projected increase in your cost estimate, that FPL does not accept any responsibility as being a cause or a portion of the cause for any of those projected cost overruns?

MR. ANDERSON: That's kind of a fuzzy question. But if the witness understands it, it's fine by me, or if he wishes it rephrased.

THE WITNESS: Could you rephrase the question, please?

BY MR. MOYLE:

Q Does FPL take any responsibility for directly causing any of the projected cost overruns, or, or is it all someone else's fault?

MR. ANDERSON: Could you just -- that's much, much better, but you keep going back to cost overruns, but the subject matter is right.

CHAIRMAN BRISÉ: I think the, the witness understood the question.

Please answer the question.

THE WITNESS: The answer to the question is we take full responsibility and accountability for the project, including the cost increases. And I've explained in my testimony the basis for the cost increase. There is no one to blame. These are legitimate scope increases.

MR. MOYLE: Okay. That's all I have. Thank you.

CHAIRMAN BRISÉ: Thank you.

FEA.

LIEUTENANT COLONEL FIKE: Thank you, Mr. Chairman. Just a couple questions.

CROSS EXAMINATION

BY LIEUTENANT COLONEL FIKE:

Q You talked about the contract with Bechtel. Is it correct then that the contract you originally had with Bechtel was modified or changed to have subcontractors be doing some of the work; is that correct? I mean, the FP&L contract with Bechtel, was it modified?

A The original -- no. The original contract with Bechtel always allowed for Bechtel to subcontract work, as long as we agreed to the selection of the subcontractors and the scope of work that they were to perform.

Q It allowed it. But how, how did, how -- was it ever changed to tell them these subcontracts are going to do the work? I mean, was there any modification done to the contract?

A No. There's no need to modify the contract because the contract already had the provision to allow the selection of subcontractors to do the work.

Q All right. Let me ask this question. How did Bechtel hire those contractors? Was there any additional contracts that Bechtel had to write to hire them to do work for them?

A Yes. Bechtel has to have a contract in place with subcontractors for them to perform work.

Q All right. So this -- were there any charges incurred by Bechtel or FP&L due to the, I guess, descoping of Bechtel's original work to do this contract? Were there any contract general administrative charges that were incurred by Bechtel or FP&L when the decision was made to subcontract the work out to the subcontractors?

A Yes. There's -- there are Bechtel administrative charges for all the contractual work that they do for subcontractors. We do take into -- we take into account the total cost for when we would ask Bechtel to bring in a subcontractor. We don't, we don't just narrowly focus on this subcontractor can do this labor part and just focus on the savings in the labor. We're going -- we evaluate what Bechtel is going to charge us for the use of that subcontractor when we compare it to what Bechtel would be able to execute that work for, if that, if that makes sense.

Q So I guess one last question then. So if -- it would have been more economical to have had the subcontracts in place for the work rather than to have had them modify the original contract to add the work.

A No, that's not correct. The original contract stands. The contract already had the provision that allows Bechtel to bring in subcontractors with our approval. Bechtel, as a part of their normal course of business, executes contracts every day with subcontractors.

Q I think you've answered the question. Yeah. You've answered the question no. Let me rephrase the question then.

If -- I think you said earlier that there were charges that were incurred by Bechtel to administer the subcontracts with the subcontractors; is that correct?

A Yes. As a part of the Bechtel contract with FPL, Bechtel is -- we are subject to pay Bechtel for contract administration, project controls, things of that nature. That's standard industry practice.

LIEUTENANT COLONEL FIKE: Okay. That's all the questions I have.

CHAIRMAN BRISÉ: SACE?

MR. WHITLOCK: No questions for this witness.

CHAIRMAN BRISÉ: Okay. FRF?

MR. LAVIA: No questions, Mr. Chairman.

CHAIRMAN BRISÉ: Staff?

MR. LAWSON: No questions.

CHAIRMAN BRISÉ: Commissioners?

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And welcome, Mr. Jones. I think this is the first time a witness has an entire binder solely to their testimony, so I think congratulations are in order for that. It made it easier to find.

I want to focus on a couple of issues. Are you aware of the project management audit that was prepared by PSC staff in June of 2012 that listed comments by FPL on contractor performance?

THE WITNESS: Yes, I am.

COMMISSIONER BALBIS: Okay. And I believe most or if not all of that is confidential, so I won't focus too much on the specifics, but there were several comments from FPL on performance of its contractor.

And my question is were there any additional costs to the project associated with some of the comments from FPL having to do with contractor performance issues in this filing?

THE WITNESS: Yes. And I'd like to answer it this way. Is that, that whoever you contract with, right, you know, you demand high performance. And part of our process that we execute at FPL with all our vendors is we provide what we call internal confidential verbatim type feedback. And so that form that's in that report is an example of that where we're very critical of Bechtel's performance.

When you say increased costs, to be totally transparent, if you're not achieving a scheduled adherence of greater than one, then by and large you're, you're spending more money than if you were performing, you know, perfectly. Bechtel, on average, achieves a schedule, I'll say a schedule execution of adherence around 80%, which is really, really very good for an EPC.

But any -- but there are -- when you read that form and you read the entire form, it really centers around a couple of modifications that turned out to be much more complicated and more difficult than either us or Bechtel had, had, had anticipated, and so there's a little bit of frustration in there.

But on the balance, any given work area in a short-term could be unperforming and it could be overachieving in another, and you shift your resources in allocations or maybe even subcontract something to a specialty vendor to achieve the overall performance you're looking for.

So in the short-term, yes, there could be increased costs. In the balance, they're performing very well.

COMMISSIONER BALBIS: Okay. Would those increased costs -- you listed in your testimony different categories: Engineering design, permitting, project management, power block engineering, et cetera. Those additional costs, would they be in the power block engineering category, or which category would they be in?

THE WITNESS: Those would be in licensing, engineering, power block. It's really across the board.

TOJ-18, that exhibit gives a number of the examples of the cost drivers and the power block engineering, if you're, if you're interested in those.

COMMISSIONER BALBIS: I was focusing specifically on the contractor performance issues, which you indicated resulted in additional costs. I was trying to understand and get a handle of that, where those costs would be in your testimony when you listed the 2011.

THE WITNESS: Well, maybe -- I want to make sure I don't mischaracterize it. Obviously if the contractor can perform more efficiently, then we have reduced costs. But the contractor is not performing out of norm; the contractor is actually performing pretty well.

An example of increased costs would be where the contractor had a human error and went to a wrong component in the plant and we had to stop work and retrain the contractor, and that had a cost impact of

$155,000.

The order of magnitude that we're talking here isn't because of contractor poor performance. Not at all. That's legitimate design evolution and complexity of construction. EPC is -- and I don't want to keep saying their name, but, you know, we have several major vendors on the job and they're performing very well. Could they perform better? Absolutely. Which would obviously result in less cost. I would not make a change.

COMMISSIONER BALBIS: Okay. And, again, I'm just trying to focus on the management audit, the comments made, any additional costs due to performance issues.

THE WITNESS: Yeah.

COMMISSIONER BALBIS: You mentioned a $155,000 item. Are there other items such as that? And if so, what's, what's, just in order of magnitude, how much are we talking? And then the follow-up question is what contractual mechanisms are in place to protect FPL and eventually the ratepayers from performance issues of FPL's contractor?

THE WITNESS: Yeah. For an order of magnitude, the type of legitimate performance issues we have are human errors or first aid type, type injuries that result in work stoppage and standdowns. And that's pretty typical in the industry, and it can range from anywhere from -- this is huge, the number of people we have on site. So when we shut down 65 electricians for a day and a half to retrain them to make sure they're going to work electrically safe, that results in about a $155,000 impact. So order of magnitude, you're, when that occurs, you're talking in the order of 100,000 or 155,000.

The protections in the contract for us of course are incentive fees around first-time quality, safety, and schedule. Obviously we grade the contractor in those areas, and they would not be entitled to their, their fee.

We also, as a matter of being, you know, very critical on their performance, we use these instances where they've fallen short as leverage in our negotiation to ask for reduced rates. You'll notice in my May testimony that Bechtel made a number of concessions to reduce their rates and, and ultimately wound up saving us tens of millions of dollars. I think it was about $46 million worth of concessions. That's what we do to protect the customer.

COMMISSIONER BALBIS: Okay. And the stator core issue with Siemens, FPL negotiated an agreement or settlement with Siemens --

THE WITNESS: That's correct.

COMMISSIONER BALBIS: -- that exceeded the three and a half million dollars that our management audit staff recommended we disallow.

Is there a similar negotiation that has taken place with the, FPL's contractor to deal with any performance issues that may have cost FPL additional money?

THE WITNESS: Yes. In, in my May filing, I list those concessions that Bechtel made. And certainly part of that was some of the performance issues that we have with Bechtel where we thought they could have been more efficient. Some of those -- well, it's not really a straight up performance issue as much as, as a human error. So, yes, some of the human error events that cost us $100,000 or $50,000, those are certainly a part of that negotiation for some of those concessions. We negotiate and receive concessions from Bechtel, Siemens, and Shaw.

COMMISSIONER BALBIS: Okay. So you're -- I just want to make sure I have a firm understanding of the amount of additional cost to FPL, and you're testifying that it's only about $155,000. So all of the issues that were listed, quoted from FPL employees in a management audit are really just a result of a $155,000 issue, or is there more?

THE WITNESS: No, sir. There was a number of examples that were in the staff audit that -- I think there was one in there for 98,000. There, there were a handful of them in there. And those we used to, to penalize our vendors on their incentive fee.

But what I'm saying is that's a small subset of what we use in leverage that we bring to bear to renegotiate terms and get better rates on our going-forward work.

COMMISSIONER BALBIS: Okay. And I just go back to the stator core work, where it was very easy for us to approve a stipulation when, you know, the negotiation with Siemens exceeded the potential disallowance. So we were, at least I was comfortable in voting for that stipulation that the customers were protected.

I'm wondering if there's any similar documentation in FPL's filing that shows that these negotiations cover any potential performance issues from the contractor.

THE WITNESS: I, I understand your, your question, and obviously I'm not answering your question. I'm saying that the handful of straight up performance issues was in the order of a few hundred thousand dollars with Bechtel. What we negotiated in concessions from Bechtel was $46 million. And so obviously the primary driver was not the few legitimate performance issues. It really centered around, you know, our view of how they could improve their efficiency and reduce their overall cost, and that's what they agreed to.

COMMISSIONER BALBIS: Okay. Well, let me change gears a little bit, and I think this is my final question.

There's a lot of talk about nonbinding cost estimates, and in my experience the, the less detail you have on a project the more uncertainty. And one of the ways to deal with the uncertainty is to include a contingency, and then you reduce the contingency as plans get further defined.

Was there a contingency in place when the original nonbinding cost estimate was prepared? I mean, just, you know, any factor of contingency to deal with those uncertainties? That way you wouldn't have such an increase in nonbinding cost estimates?

THE WITNESS: Yes. It is my understanding that a, an engineering firm was commissioned, did several months' worth of study for the EPU project, and, and did produce a high level estimate to which contingency was applied in the needs filing. And, and from that, that's what was, the project was, was, was approved based on that analysis.

Obviously, you know, since that time, you know, a lot, lot has changed. You know, nuclear being as complex as it is and trying to do this major construction on an operating nuclear facility has, has proven to be, you know, quite challenging. But, but obviously we've proven that we can be successful, we are being successful, we are delivering what this Commission asked us to deliver, and it's very cost-beneficial to the customers.

COMMISSIONER BALBIS: Okay. Thank you. That's all I had.

CHAIRMAN BRISÉ: Any further questions?

Okay. Redirect.

REDIRECT EXAMINATION

BY MR. ANDERSON:

Q During cross-examination you were asked a question and were given the opportunity to explain why didn't FPL establish a target price for completion of the Turkey Point uprate.

A The reason that we decided not to establish a target price for Turkey Point was really based on the several months of experience that we had in dealing with our EPC on the target price for St. Lucie, and there was a lot of, of back and forth over what was in scope and what was not in scope.

At the end of the day, you're committed, the work is the work. You can't put a car on the road with three tires. And, and kind of felt that it was becoming a, a distraction actually. And, and given that the estimated completion that was provided by Bechtel was high in our view, we felt it wasn't really in the best interest of the customers to settle on that as a target price and to focus all our energy and attention on minimizing their headcount on the project.

The cost of this project at this point is really just driven by the headcount and the human capital necessary to complete the construction, and that's where our focus is. Thank you.

Q Commissioner Balbis had asked you some questions about contractor performance. Is perfect contractor performance achievable?

A No, it isn't.

Q Has FPL prudently managed its EPC contractor in the circumstances where FPL has expressed concerns about performance?

MR. MOYLE: I'm going to object on leading.

BY MR. ANDERSON:

Q The question was -- let me repeat it.

Has FPL prudently managed --

MR. MOYLE: It's still leading.

MR. ANDERSON: There's nothing leading about that.

MR. MOYLE: How has FPL managed this project.

MR. ANDERSON: I said has, has FPL prudently managed its EPC contractor in the circumstances where FPL has expressed concerns about performance? That's a yes or no question.

MR. MOYLE: It's still leading.

CHAIRMAN BRISÉ: Mary Anne?

MS. HELTON: I don't think it's a leading question. In my recollection, a leading question is it leads the witness to the answer that is requested. And I believe this is, as Mr. Anderson said, a yes or no question.

CHAIRMAN BRISÉ: All right. I would tend to agree with that.

THE WITNESS: Yes.

BY MR. ANDERSON:

Q Please very briefly explain.

A Well, obviously, you know, it's a very complex project involving the four reactors. We're expending a million manhours of effort every single month. That's 500 man years in a month. And quite frankly, I don't know of another EPC that could pull this off. This is an amazing feat and something that, that my entire team, including my major suppliers, are extremely proud of.

Q Finally, have the concessions FPL has negotiated from Bechtel with respect to the project, including focusing on 2011, been greater in value than the performance matters that you described with Commissioner Balbis?

A Significantly.

THE WITNESS: We have no further questions.

CHAIRMAN BRISÉ: All right. Thank you. And at this point we will deal with exhibits.

MR. ANDERSON: Yes, please, Mr. Chairman. We'd offer 51 through 75, 112, 113, and 131.

CHAIRMAN BRISÉ: All right. If there are no objections, we will enter 52 -- is it, you said 51 or 52?

MR. ANDERSON: Yes, sir, but I'll check.

CHAIRMAN BRISÉ: 51 through 75, 112, 113, and 131. Seeing no objections, those will be entered into the record.

(Exhibits 51 through 75, 112, 113, and 131 admitted into the record.)

MR. ANDERSON: Thank you.

CHAIRMAN BRISÉ: And I don't think there were any other exhibits proffered by any other Intervenors for this witness.

MR. ANDERSON: That's correct. Mr. Jones will be returning for rebuttal. We do have our next witness, Mr. Ferrer, available and ready to proceed.

CHAIRMAN BRISÉ: Sure. You may proceed.

Commissioner Graham is going to chair this portion. I have to go upstairs to take care of a couple of administrative things.

MR. ROSS: Mr. Ferrer is on the stand and he was sworn this morning, Mr. Chairman.

COMMISSIONER GRAHAM: Sure.

Whereupon,

ALBERT M. FERRER

was called as a witness on behalf of Florida Power & Light Company, and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. ROSS:

Q Good afternoon. Would you please state your name and business address.

A My name is Al Ferrer. I am Vice President of the Power Consulting Group at Burns and Roe, 800

Kinderkamack Road, in Oradell, New Jersey.

Q Have you prepared and caused to be filed 12 pages of prefiled direct testimony in this proceeding on March 1st, 2012?

A Yes, I have.

Q Do you have any changes or revisions to your prefiled direct testimony?

A Yes, please. On page 7, line 12, I'd like to change the date of June of 2011 to January of 2011.

And on page 10, line 19 through 23, we keep the FPL responses timely and thorough, comma, and NRC has since issued the license amendments for Turkey Point 3 and 4 and St. Lucie 1.

On page 11, the top three lines are deleted.

Q With the changes that you just indicated, if I asked you the same questions today contained in your prefiled direct testimony, would your answers be the same?

A Yes, sir.

MR. ROSS: Mr. Chairman, I ask the prefiled direct testimony of Mr. Ferrer as changed be inserted into the record as though read.

COMMISSIONER GRAHAM: We will insert Mr. Ferrer's amended prefiled direct testimony into the record as though read.

MR. ROSS: Mr. Ferrer is sponsoring no exhibits.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF ALBERT M. FERRER

DOCKET NO. 120009-EI

MARCH 1, 2012

Q. Please state your name and business address.

A. My name is Albert M. Ferrer. My business address is 800 Kinderkamack Road, Oradell, New Jersey 07649.

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

A. I am employed by Burns and Roe Enterprises, Inc. (BREI) as Vice President, Power Consulting Division.

Q. Please describe BREI.

A. BREI is an engineering, procurement, construction, operations, and maintenance company that provides services to private and governmental power industry clients worldwide.

The Power Consulting Division provides consulting services to the nuclear and fossil power industry. Services provided by the Division include owner's engineer, independent engineering, due diligence, acquisition services, uprate analyses, life extension studies, engineering, procurement and construction (EPC) oversight, contract evaluation and EPC project management.

Burns and Roe's nuclear experience includes some of the earliest U.S. commercial nuclear power plants. Burns and Roe have been involved in the design of eight commercial nuclear power plants. More recently, Burns and Roe provided a conceptual design of the Traveling Wave Reactor - a 3,000 megawatt sodium-cooled reactor using a revolutionary core design funded by the Gates Foundation. The Babcock & Wilcox Company used Burns and Roe to develop conceptual designs for their mPower™ reactor - a passively safe, small modular reactor with a below-ground containment structure. Burns and Roe evaluated General Electric's Economic Simplified Boiling Water Reactor for compliance with Electric Power Research Institute's Utility Requirements Document. For the U.S. Department of Energy (DOE), Burns and Roe performed independent due diligence investigations for four new U.S. nuclear plants in support of the DOE's utility loan guarantee project applications. Burns and Roe also participated in the development of three combined Construction and Operating License Applications for new nuclear power plants in the southeast U.S.

Q. Please describe your educational background and professional experience.

A. I hold an M.S. in Nuclear Engineering from New York University and a B.S. in Mechanical Engineering from Manhattan College, with honors. I have been Vice President of BREI's Power Consulting Division since 2005. I report directly to the Chairman and President of BREI. In my current position I provide management, executive leadership, and oversight for all engineering consulting services performed by the Division including those provided by its specialists and consultants.

Prior to joining BREI, I was Senior Vice President and Managing Director for Stone and Webster, with responsibility for the firm's Strategic Management, Markets and Regulatory, and Project Finance Services practices. During my career at Stone and Webster, I held positions ranging from project engineer to manager of major EPC power plant projects involving site feasibility, environmental impact evaluations, conceptual engineering, detailed design, procurement, cost and estimating, construction engineering, construction management, and start up and testing of a variety of technologies including coal plants, simple cycle and combined cycle gas plants, nuclear plants, geothermal plants, and small hydro facilities. As a project engineer or project manager, I was responsible for cost and scope control, planning, coordinating, scheduling and supervising engineering activities for various nuclear projects. I also provided expert testimony at hearings before the Nuclear Regulatory Commission's (NRC) Advisory Committee on Reactor Safeguards involving the construction permit process for nuclear plants.

Q. **What is the purpose of your testimony?**

A. My testimony summarizes an independent review conducted by myself and other BREI Power Consulting Division personnel regarding Florida Power & Light Company's (FPL) execution of the Extended Power Uprate (EPU or Uprate) related activities at St. Lucie (PSL) and Turkey Point (PTN) power plants in 2011. The purpose of this review was to determine whether FPL's project activities executed in 2011 were reasonable and prudent. In conducting the review, we applied the prudence standard that has been used by the Florida Public Service Commission, which is whether FPL's management actions and decisions are within the range of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should have been known, at the time the decision was made. Hindsight review is impermissible.

Q. **Please summarize your testimony.**

A. FPL took actions and made decisions on the execution of the PSL and PTN nuclear plant EPU project during 2011 in a reasonable and prudent manner. FPL is pursuing the EPU project consistent with sound project management practices commonly used for other prudently managed projects in the industry, is aggressively managing the project and its contractors, has a reasonable and manageable project schedule and execution approach, has a prudent approach to pursuit of NRC licensing for the project, and is taking appropriate and prudent actions to mitigate project risks.

Q. **Please describe how BREI conducted its review.**

A. I led the BREI review, which was comprised of senior level personnel with experience in nuclear plant engineering, nuclear plant licensing, nuclear plant operations, power plant construction, and project controls. The BREI review team: a) conducted interviews with FPL personnel at its Juno Beach headquarters and at the PSL and PTN sites; b) prepared written data requests to FPL personnel and reviewed FPL's responses to these questions; c) reviewed technical reports, letters, drawings, procedures, schedules, descriptions of organization roles and responsibilities, qualifications of EPU team personnel, correspondence with the NRC, and prior testimony filed with the Florida Public Service Commission; and d) observed on-going EPU activities at both the PSL and PTN sites. BREI personnel were also given ready access to EPU project personnel, documentation, and the PSL and PTN sites.

Q. Please describe the major areas of your review.

A. BREI reviewed the following areas:

- Project Plans, Outage Execution Plans, Schedules and Organization;
- Engineering and the Engineering Work Control Process;
- Project Schedule; and
- License Amendment Request Related Activities.

Q. Please describe the conclusions of BREI's review of the EPU project plan, schedule, and organization.

A. Three Project Plans were reviewed for the EPU Project - one overall for the FPL fleet and one each for PSL and PTN. BREI also reviewed numerous documents pertaining to the implementation of the EPU project, including schedules, corrective actions, procedures, meeting minutes, NRC correspondence, and internal audit reports. In addition, BREI personnel visited FPL corporate offices and both sites to conduct interviews with EPU project personnel.

BREI found that the various EPU Project procedures were being utilized by team members. BREI also found that the EPU project team was well aware of challenges and was actively implementing the strategies that had been developed to mitigate identified challenges.

In our experience, projects that are performed on an expedited schedule can create additional and unique project management challenges due to the compressed time frame and potential additional work as discoveries are made. BREI found that the FPL EPU project management team has properly managed the project taking into account the great challenges of performing this extremely large and complex project on an expedited time frame. FPL exercised vigilant oversight of the project and the deliverables. FPL maintained strong workforce oversight to support and fortify contractor performance. FPL project team members use sophisticated and state of the art performance metrics to manage project performance. Experienced project management personnel continually review contractor deliverables including engineering reports, drawings, calculations, and work packages. In addition, FPL has appropriately assigned defined scopes of work to additional, well-qualified contractors to enhance schedule and budget performance. Consistent with good nuclear industry practice, the EPU project team has also sought to learn from relevant EPU project experience by contacting and exchanging lessons learned with industry peers that are also implementing EPUs. FPL has also thoroughly incorporated the essential elements of risk management into the project to track challenges and develop mitigation strategies for engineering, procurement, construction, and licensing.

Q. Please summarize the conclusions of BREI's review of EPU engineering and the engineering work control process.

A. During 2011, FPL closely monitored the engineering progress, prioritized modifications based upon potential severity of cost and schedule impacts, and selected contractor and subcontractor assignments to enhance quality, cost, and schedule performance. These are proactive measures taken by FPL to minimize cost and schedule impacts during construction caused by delays in issuance of engineering modification packages and work planning packages and by discovery of the need for additional work during outage performance. In addition, in ~~June~~ January of 2011, decisions were made to change the outage start dates. The PSL Unit 1 outage was deferred approximately three months, the PSL Unit 2 was deferred approximately seven weeks, and the PTN Unit 4 outage was deferred approximately five weeks. FPL also decided to change the durations of the EPU outages at PSL to provide, in part, additional time for engineering, planning, procurement, and outage preparation to ensure successful outages.

The magnitude of the work being performed for the implementation of four EPUs at four units is significant. The fifteen month schedule for completion of all four outages is aggressive. FPL management has maintained vigilant oversight of the project and has increased the intensity of its management oversight as necessary. Based upon our interviews of the EPU project team, the team leaders and team members are well-qualified, possess a positive "can-do" attitude and have put forth significant efforts to ensure the success of its contractors and the project while maintaining teamwork among internal and external team members. BREI also noted that personnel with EPU experience on other nuclear projects are being used to support FPL's EPU project. FPL's use of personnel with recent EPU implementation experience has also helped the FPL project team.

BREI also compared FPL's EPU project organization and approach to Nuclear Energy Institute (NEI) 08-010, "Roadmap for Power Uprate Program Development and Implementation," Revision 0, issued July 2009. This guidance document was developed by the nuclear energy industry to provide a high level roadmap for power uprate project development and implementation. This document builds on lessons learned from previous uprate projects and provides general guidance which includes a brief overview of power uprates, the regulatory process, guidelines on targeting uprated thermal power, best practices and operating experience from previous uprates, and keys to success for licensing, implementation and operation at power uprate conditions. The roadmap provides specific guidance for decision-making processes, project management and development, program and equipment analysis, regulatory and licensing processes, and project implementation. The NEI document provides that the features of a strong power uprate project include: fleet-wide effort; feasibility studies; strong project management; dedicated resources; owner's engineer/independent engineer's emphasis; contract support; a risk management strategy; assessments, audits and oversight; and an EPC structure.

Based on BREI's extensive document reviews and roundtable discussions with project personnel, BREI concludes that the features suggested by the NEI uprate guidance document for a successful EPU project have all been implemented by FPL and were being maintained throughout 2011. This was evidenced by FPL's project execution plans and decisions, periodic meetings and status reports, compliance with EPU Project Instructions, and compliance with corporate procedures.

Q. Please summarize the conclusions of BREI's review of EPU project schedules.

A. BREI performed a detailed review of the EPU project schedules for PTN and PSL. The PTN EPU Primavera P6 schedule, a detailed computerized schedule program for the EPU project, is detailed with a total of over 100,000 activities including 30,000 activities in engineering, 15,000 activities in simulator, training and procedures, 24,000 pre-outage activities and 25,000 outage related activities. The PSL EPU Primavera P6 schedule has a total of over 90,000 activities including approximately 40,000 engineering activities and approximately 13,000 related to the installation efforts. The schedules include an appropriate and reasonable number of activities for projects of this magnitude. Based on BREI's prior experience, FPL is appropriately managing the activities in the schedules.

Q. Please summarize the conclusions of BREI's review of FPL's NRC licensing activities.

A. BREI reviewed FPL's responses to NRC Requests for Additional Information (RAI) submitted during 2011 for both PSL and PTN license amendment request efforts. FPL responses to NRC RAIs were complete, clearly written, and timely submitted. A few of FPL's responses were the subject of follow-up questions by the NRC, but most were adequately addressed with a few technical questions outstanding at the time of our review. In our experience, this exchange of information is typical for an NRC license amendment review process. Additional delays in NRC review of FPL's proposed license amendments due to agency resource constraints and emergent issues arising before the NRC are possible. As a result of information unrelated to FPL's EPU Project presented to the NRC by Westinghouse on December 6, 2011, FPL was requested by the NRC to address the impact of thermal conductivity degradation (TCD) on the PTN EPU safety analyses. FPL provided a response to the NRC request for information (RAI) via letter dated December 31, 2011. The FPL response was timely and thorough. FPL's response led to a resolution of the issue where, if finally approved by the agency, the NRC would issue a proposed license condition regarding the use of computer code changes to explicitly account for TCD, rather than postpone approval of the EPU license amendment request for PTN. While the resolution of this issue

See comments in Vol. 6, Page 1132 Lines 10-13.

~~has not been finalized by the NRC, FPL is actively engaging the NRC to facilitate the timely issuance of the license amendments and has prudently developed alternate plans should delays occur.~~

Q. Did you also review FPL's management actions with respect to work stoppages caused by contractor personnel errors?

A. Yes. There were two notable work stoppages caused by contractor personnel errors in 2011:

1. In February 2011, Siemens inadvertently left an alignment pin inside the generator stator which caused core iron damage during subsequent testing. Siemens repaired the damage on an expedited basis over the next several weeks. Following Siemens repair efforts, the generator was tested and determined to be satisfactory. The generator has operated satisfactorily since the outage ended.

2. In, December 2011, Bechtel electrical craft personnel commenced work on a motor control center different from the one specified in their detailed work instructions. Upon discovery, the supervisor immediately stopped the work. No injuries occurred and no equipment was damaged. The Bechtel electrical personnel were retrained in equipment clearance processes and subsequently returned to work. During this time, other EPU work continued. The outage duration was not impacted and the cost to FPL was minimal.

Based on our review, we have determined that FPL's management actions during 2011 were appropriate. The contractors assigned to the EPU project who were responsible for the contractor personnel errors were properly qualified, trained, briefed and instructed consistent with good nuclear industry practice. Despite such prudent and reasonable FPL management actions, some personnel errors on a project of this complexity and magnitude will inevitably occur because workers are not infallible. Moreover, it is consistent with prudent industry practice that when such errors occur, work is stopped and workers are retrained to prevent recurrence.

Q. Does this conclude your testimony?

A. Yes.

BY MR. ROSS:

Q Mr. Ferrer, have you prepared a summary of your direct testimony?

A Yes, I have.

Q Would you please provide that to the Commission now.

A Thank you.

Good afternoon, Commissioners. I am Al Ferrer, Vice President of Burns and Roe's power consulting division. I have more than 30 years' experience in the commercial nuclear power industry. Burns and Roe is an internationally known expert on power consulting, engineering, procurement, construction, and operations firm.

My testimony documents Burns and Roe's independent review of Florida Power & Light Company's execution of the extended power uprate project at St. Lucie and Turkey Point power plants in 2011.

I led the Burns and Roe team, which was comprised of personnel with extensive nuclear power plant experience.

Our team conducted interviews with FP&L personnel, received answers to written data requests, reviewed numerous project documents, and observed ongoing EPU activities. We were given unlimited access to project personnel, documents, and to the nuclear power plant sites.

We concluded that FP&L's actions and decisions on the execution of the St. Lucie and Turkey Point EPU project during 2011 were made in a reasonable and prudent manner. FP&L is pursuing the EPU project consistent with sound project management practices commonly used for other prudently managed projects in the industry. FP&L is aggressively managing the project and has a reasonable and manageable project schedule and execution approach. FP&L has taken appropriate and prudent actions to mitigate the risk of this extremely large and complex project.

Consistent with good nuclear industry practice, the EPU project team has learned from other EPU project experience by exchanging lessons learned with industry peers. FP&L has also incorporated the essential elements of risk management into the project to attract challenges and develop mitigation techniques.

With respect to engineering, FP&L closely monitored the progress of product engineering, prioritized modifications based on cost and schedule impacts, selected experienced contractors to enhance performance, and adjusted product execution and outage schedules appropriately.

FP&L demonstrated a prudent approach to pursuit of NRC licensing for the project, resulting in the successful NRC approval of complex licensing amendments authorized in the uprates for Turkey Point Units 3 and 4 and St. Lucie 1.

This concludes my summary. Thank you.

MR. ROSS: Mr. Ferrer is available for cross.

COMMISSIONER GRAHAM: Thank you, sir. Sir, welcome.

OPC.

(Transcript continues in sequence in Volume 7.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 19th day of September, 2012.

Linda Boles

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