FILED AUG 14, 2013
DOCUMENT NO. 04755-13
FPSC - COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130009-EI

NUCLEAR COST RECOVERY CLAUSE.
_______________________________/

VOLUME 5

Pages 830 through 970

PROCEEDINGS: HEARING

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

DATE: Monday, August 5, 2013

TIME: Commenced at 5:03 p.m.
Concluded at 5:47 p.m.

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

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6732

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
13-38			948
68	FR-1 (Description on Comprehensive Exhibit List)	956	956

P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

CHAIRMAN BRISÉ: Okay. Next witness.

MR. ANDERSON: FPL calls as its next witness Terry Jones.

MR. McGLOTHLIN: Mr. Chairman, while Mr. Jones is settling in, I'd like some clarification from counsel with respect to the procedure to be followed. You'll recall that at the outset you approved a stipulation whereby FPL and OPC agreed to rely on opening statements and briefs and waive cross.

With respect to Doctor Sim, I understand that his testimony was always going to be subject to cross because of SACE's position on it. On the other hand, Mr. Jones' testimony has already been moved into the record. And based upon the stipulation, which was always subject to the prerogative of the Commissioners to ask whatever questions they want, but it seems to me that fairness would indicate that there would be no summaries, particularly of the rebuttal testimony, under these circumstances.

CHAIRMAN BRISÉ: Sure. To me that sounds fair. I think there are questions that Commissioners have, and I think we'll get right into the questions because they are arising from the testimony that is prefiled. Okay.

MR. ANDERSON: As we said earlier, it's the Commission's hearing. I would note that he has got a terrific three-minute summary that catches you up on completion of the project. And I agree with Mr. McGlothlin, we agree there is no need to do the rebuttal, but it really is a nice focuser, if you want it. But we respect however you want to go.

CHAIRMAN BRISÉ: Understood. But you all have an agreement, and we agreed to the agreement, and so we will stand by the agreement.

MR. McGLOTHLIN: Thank you, sir.

MR. ANDERSON: May we proceed?

CHAIRMAN BRISÉ: Give me one second just to make sure that everyone is here.

MR. ANDERSON: Okay.

(Pause.)

MR. ANDERSON: It really was my favorite summary.

(Audience laughter.)

CHAIRMAN BRISÉ: I believe you.

MR. MOYLE: I have a lot of cross on that summary.

(Audience laughter.)

CHAIRMAN BRISÉ: I'm sure you do.

All right. Mr. Anderson.

MR. ANDERSON: Thank you, Chairman Brisé.

FPL has called as its witness Terry Jones.

TERRY JONES

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

DIRECT EXAMINATION

BY MR. ANDERSON:

Q. And you have been sworn already, is that right?

A. That's correct.

Q. Did you file prefiled testimony in this case?

A. That is correct.

Q. In March you filed 43 pages, and on May 1 you filed 23 pages?

A. Yes.

Q. You had a number of exhibits, labeled TOJ-1 through 26, is that right?

A. That's correct.

MR. ANDERSON: Chairman Brisé, these are reflected as Exhibits 13 through 38 in Staff's Consolidated Exhibit List.

BY MR. ANDERSON:

Q. Did you also have some errata that were filed on July 3rd?

A. That is correct.

Q. And you had some revised rebuttal testimony, 11 pages, dated July 26, is that right?

A. That is also correct.

MR. ANDERSON: FPL requests that all the referenced testimony be entered into the record as though read.

CHAIRMAN BRISÉ: Okay. We will enter all the testimony into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 130009-EI

MARCH 1, 2013

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, FL 33408.

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 Project 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. 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, and costs incurred in 2012. I also describe the procedures, processes, and controls that ensure FPL's EPU expenditures are reasonable and the result of prudent decision making, and 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. FPL is successfully completing the EPU project that was approved in 2007 to meet customer needs for additional generation in the 2012-2013 timeframe. FPL was commissioned to deliver 399 MWe (net of co-owners' shares) by the end of the project, and it has already met that goal. In fact, approximately 400 MWe of the more than 500 MWe that FPL expects the project to provide is already serving customers. The uprate work at St. Lucie Units 1 and 2 and at Turkey Point Unit 3, which work FPL completed in 2012, resulted in 34% more power than FPL initially projected those units would deliver in its need filing, and as of year end 2012, was saving customers approximately $90 million in fuel costs on an annualized basis. And the work at the fourth and final unit, Turkey Point Unit 4, was nearing completion. This enormous effort required the employment of thousands of workers. In 2012, an average of 3,500 personnel were employed to work on the EPU project every day, and at its peak in 2012, 4,000 additional workers were employed by the EPU project. In total, the 2012 EPU work required over 12 million man hours of effort – over half of the approximately 22.4 million man hours estimated for the entire EPU Project.

To put the total amount of human effort committed to FPL's Florida EPU project into perspective, the project's 22.4 million man hours of effort is about the same amount of labor as was recently employed to construct Dubai's Khalifa Tower, which at 2,722 feet is the tallest building in the world and took about six years and 22 million man hours to construct. What should also not be lost is that the EPU project is far more complex than even such a major building project, since the EPU project's construction work was all performed on and at operating nuclear power plants.

The additional nuclear generation from the EPU project is providing significant and quantifiable benefits for customers without expanding the footprint of FPL's existing nuclear power plant sites and without burning natural gas or foreign oil or emitting greenhouse gasses. FPL's 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 Nuclear Cost Recovery (NCR) statute, and the Commission's careful implementation of that policy through the NCR Rule – all of which permits recovery of only a small fraction of FPL's investment that is prudently incurred (*i.e.*, only carrying costs, recoverable O&M, and partial-year in service revenue requirements) through FPL's Capacity Cost Recovery clause. The vast majority – FPL's capital investment – is recovered over the lives of the uprated units, as they are producing power for customers. TOJ-2 depicts, as of December 31, 2012, the FPL investment of approximately $2.9 billion as compared to its Capacity Cost Recovery clause recovery of approximately $320 million, as well as the 2012 workforce summary for the project.

FPL successfully managed the most intensive year of EPU project implementation work in 2012, which included the following:

- Implementation and completion of major modifications during the St. Lucie Unit 1 EPU outage and a brief (6-day) License Amendment Request (LAR) outage, completing the uprate of that unit;
- Implementation and completion of major modifications during the Turkey Point Unit 3 EPU outage, completing the uprate of that unit;

- Implementation and completion of major modifications during the St. Lucie Unit 2 EPU outage, completing the uprate of that unit; and
- Initiation and implementation of major modifications during the Turkey Point Unit 4 EPU outage, which is scheduled to be complete in early 2013.

This implementation work required substantial and iterative engineering design and construction planning, as well as continuous forward-looking project management that resulted in adjustments to outage dates and outage durations, revisions to implementation plans, and intensive contractor oversight and management. Additionally, FPL received all required Nuclear Regulatory Commission (NRC) LAR approvals.

FPL prudently incurred approximately $1,429 million of EPU costs during 2012. Challenges were experienced in the planning and execution of major modifications of "first time evolution" at the first unit at each site – St. Lucie Unit 1 and Turkey Point Unit 3. By "first time evolution" I mean that these modifications were of a high complexity and had not been performed before. As a result, engineering and implementation took more people and more time at the first unit at each site. The project team incorporated modification design changes and lessons learned in the planning and execution of the EPU work at the second unit at each site – St. Lucie Unit 2 and Turkey Point Unit 4. Ultimately, all of the work scheduled to occur in 2012 was performed and resulted in accomplishment of the project MWe goal, while completion of Turkey Point Unit 4 in 2013 will push the output even higher to a project total of over 500 MWe.

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, 2012 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, St. Lucie and Turkey Point Plant Photographs
- Exhibit TOJ-4, Illustration of Modifications by Unit
- Exhibit TOJ-5, EPU Project Electrical Output Status
- Exhibit TOJ-6, EPU Project Schedule Overview as of December 31, 2012
- Exhibit TOJ-7, 2012 EPU Cost Variance Drivers
- Exhibit TOJ-8, EPU Work Activities List as of December 31, 2012
- Exhibit TOJ-9, EPU Equipment Placed In Service in 2012
- Exhibit TOJ-10, EPU Project Instructions (EPPI) Index as of December 31, 2012
- Exhibit TOJ-11, EPU Project Reports 2012
- Exhibit TOJ-12, Summary of 2012 EPU Construction Costs

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

A. My testimony includes the following sections:

1. Project Summary
2. 2012 Project Activities and Results

3. Project Management Internal Controls
4. Procurement Processes and Controls
5. Internal/External Audits and Reviews
6. "Separate and Apart" Considerations
7. 2012 Construction Costs

PROJECT SUMMARY

Q. What is the EPU Project?

A. The EPU project is increasing 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. Photographs of examples of some of this EPU work are attached as Exhibit TOJ-3, and an illustration of the component replacements and modifications at each unit are attached as TOJ-4. Each replacement/modification 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 has 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 is modifying 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, FPL has experienced far greater engineering, construction, and cost uncertainties since FPL is performing the EPU project on existing operating nuclear units. FPL has performed almost all of the modifications during the units' pre-planned refueling outages. Performing the uprate work during the refueling outages minimized the amount of time that these low fuel-cost generators were off line.

Q. How are customers benefiting from the EPU project?

A. During 2012, completed outages resulted in an increase of approximately 400 MWe output for FPL's customers. Upon completion in 2013, FPL expects the EPU project to produce in excess of 500 MWe for FPL's customers. 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.

Q. When did 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 369 MWe, was realized as each of three units returned to service in 2012, resulting in approximately 400 MWe being provided by the end of 2012. At the completion of the final Turkey Point Unit 4 outage, the EPU project electrical output will be in excess of 500 MWe. Exhibit TOJ-5, EPU Project Electrical Output Status, demonstrates the timing of the additional output that has been or will be realized.

Q. As of December 31, 2012, what was the overall EPU project schedule?

A. Exhibit TOJ-6, EPU Project Schedule Overview as of December 31, 2012, illustrates at a high level the tens of thousands of integrated activities that have been accomplished during the project and especially during 2012.

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 Power 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. Additionally, the project benefits from the experience of previous unit outages where other project work was performed and lessons learned for future Uprate modification implementation activities.

2012 PROJECT ACTIVITIES

Q. What key activities occurred in 2012 in execution of the EPU project?

A. Key activities that occurred in 2012 included:

- Final responses to NRC Request for Additional Information (RAIs) and NRC approval of all EPU LARs -
  - Turkey Point Units 3 & 4 EPU LAR - approved June 15, 2012,
  - St. Lucie Unit 1 EPU LAR - approved July 9, 2012, and
  - St. Lucie Unit 2 EPU LAR - approved September 24, 2012;
- Extensive modification engineering for the 2012 EPU outages, including completion of approximately 220 plant design modification packages;
- Continued scheduling and planning for implementation of the modifications in proper sequence, including detailed constructability reviews, and forward-looking project management resulting in adjustments to outage dates, durations and project plans;
- The successful completion of four outages: two at St. Lucie Unit 1, one at Turkey Point Unit 3, and one at St. Lucie Unit 2. The second outage at St. Lucie Unit 1 was a short, six-day outage ("LAR outage") where instrumentation changes and procedure updates were needed to support

the uprate conditions. These outages resulted in an increased electrical output of approximately 400 MWe for FPL's customers;

- The start of the final Turkey Point Unit 4 outage in November of 2012; and
- Continuous intensive management of major vendors, including the EPC vendor Bechtel.

LICENSING

Q. Please describe the license amendment support activities in 2012.

A. The NRC completed its reviews of FPL's EPU LARs in 2012. FPL management and its licensing management regularly met with the NRC management and lead EPU reviewers to ensure all needed responses to NRC RAIs were expeditiously completed and thoroughly explained to NRC reviewers. The NRC review and approval time for each EPU LAR was originally estimated to be approximately 14 months following submittal to the NRC; however, actual review and approval times were significantly longer primarily due to NRC resource constraints and industry events. The St. Lucie Unit 1 EPU LAR took approximately 20 months, the St. Lucie Unit 2 LAR took 19 months, and the Turkey Point EPU LAR took approximately 20 months for the NRC to review and approve.

As a result of the extended review schedule caused primarily by NRC resource constraints and industry events, FPL was required to continue to retain the services of its LAR engineering analysis vendors for a longer duration than anticipated.

The extended review time also increased the fees FPL was required to pay to the NRC.

Q. Did FPL make adjustments to outage modification assignments and outage dates in 2012?

A. Yes. There was substantial NRC schedule uncertainty with respect to the issuance of the EPU LARs. Because FPL was concerned about completing an outage prior to receipt of the necessary EPU LAR, FPL implemented a decision in 2012 to move outage dates out to provide added certainty that the NRC would complete their reviews and approve the EPU LARs prior to a unit being ready to return to service at the uprated power level. This move in outage dates also added time for additional design engineering, which supported more planning, readiness for the outages, and more outage schedule certainty. However, the movement of the outage start dates required FPL to maintain personnel at the units longer, adding to project costs in 2012. The NRC regulatory delays also required FPL to move a few Uprate modifications out of the St. Lucie Unit 1 2012 outage and into the additional, short duration St. Lucie Unit 1 EPU LAR outage, which included instrumentation modifications, along with set point changes and procedure updates to permit operation in the uprate condition.

LONG LEAD PROCUREMENT

Q. Please describe activities related to the Long Lead Procurement phase in 2012.

A. In 2012, FPL essentially completed the Long Lead procurement phase. Most long lead procurement items were received, inspected, and stored or prepared for installation at the St. Lucie and Turkey Point plants. These items included the massive components necessary to generate more electricity at each unit, including steam turbine rotors, generator rotors, moisture separator reheaters, feedwater heaters, and main feedwater pumps. Many of these items are depicted in Exhibit TOJ-3.

ENGINEERING DESIGN MODIFICATION

Q. Please describe the activities related to the Engineering Design Modification phase in 2012.

A. The engineering design modification process is the process by which the detailed modification packages are prepared. Calculations are performed, construction drawings are issued, general installation instructions are provided, and high level testing requirements are identified. "Design Evolution" or "scope growth" in this context refers to 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, or the need to design modifications for other plant systems that are discovered to be impacted by a planned modification. During the EPU engineering efforts, every system in the secondary side of the St. Lucie and Turkey Point plants was impacted, and in some instances multiple times, as a result of required modifications.

Due to design evolution and complexity of construction, modification engineering and work package preparation took longer than anticipated in 2012. 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 engineering design work.

IMPLEMENTATION

Q. Please discuss the magnitude of on-line and outage EPU work that was successfully completed or initiated in 2012.

A. Including the engineering design process described above, the EPU work required:

- An augmented staff of approximately 4,000 additional people at its peak;
- Over 58,000 individually planned, scheduled, and monitored activities supporting approximately 10,600 work packages; and
- Over 12 million man hours of work.

It also involved 4,541 large bore pipe welds, 7,846 small bore pipe welds, 33,791 feet of electric wiring conduit, 250,542 feet of electrical cable, and 29,980 electrical terminations.

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

A. In addition to the substantial modification engineering described above that was performed for upcoming outages, extensive construction planning and logistical work is also performed. And just as additional scope was identified during the engineering design modification phase, additional scope was identified during the construction planning and detailed constructability reviews.

In 2012, FPL and its vendors performed walkdowns and developed subcontractor estimates, labor estimates, security plans, commodities, logistics, and the oversight structure needed to support the implementation activities. Often, new construction "scope" was 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 safely for a particular modification must be increased. This was especially true at Turkey Point. In addition to the need for more workers, the footprint of the plant is very compact, further increasing the complexity to change out equipment and safely perform modifications. More interferences exist, requiring in many cases extensive efforts to remove them and provide access to the equipment. Examples of design, implementation, and constructability complexities faced in 2012 and an explanation of the major drivers of the cost variance in 2012 are provided in Exhibit TOJ-7.

Q. Please describe the St. Lucie Unit 1 EPU implementation outages that were completed in 2012.

A. St. Lucie Unit 1 completed its second EPU outage in April, with the exception of the LAR outage activities. The EPU outage required replacement or modification of all major equipment required for operation in the uprate condition. This work is detailed in Exhibit TOJ-8, EPU Work Activities List as of December 31, 2012. The unit was initially returned to service at the pre-uprate condition power levels. The NRC then approved the St. Lucie Unit 1 EPU LAR July 9, 2012. Because of extensive preparation and planning, FPL successfully executed the brief LAR outage before the end of July to upgrade instrumentation, set-points, logic, and procedures for operation in the uprate condition. Extensive plant testing was conducted following the return to service with the final 100% power uprate condition providing an additional 148 MWe for FPL's customers. Exhibit TOJ-9 details the equipment placed in service in 2012 at each of the units, including St. Lucie Unit 1. Exhibit TOJ-3, pages 1 to 3, includes photographs of the St. Lucie plant, worker parking, and equipment which increased the complexity and logistics of the project, and examples of the large pieces of equipment that are required to support the increased power production. In total, the work for the St. Lucie Unit 1 outages required the following:

- Augmented staff of 1,847 additional people at its peak;
- Approximately 12,000 individually planned, scheduled, and monitored activities supporting 2,782 work packages; and
- Approximately 1,832,000 man hours of work.

Q. Did FPL experience engineering design scope growth and constructability complexities associated with the EPU work on St. Lucie Unit 1?

A. Yes. The majority of the EPU modifications performed during the St. Lucie Unit 1 outage were "first time evolution" major modifications which affected many large pieces of equipment and components, where interferences had to be removed to provide access. During component removal, discovery required more engineering design, scheduling and planning, constructability reviews and ultimately more time than planned to perform the required modifications. Performing these EPU modifications on a licensed plant required added care and safety considerations to ensure nuclear regulatory requirements were satisfied. These factors added to the complexity of performing the modifications which were contributors to a longer duration of the first St. Lucie Unit 1 outage than planned.

Following the implementation of the modifications, in early 2012, a systematic turnover to operations was required to ensure the systems would perform their functions reliably after implementing the EPU modifications. This plant commissioning required engineers, technicians, and craft support to test the various system controls, logic functions, and verify and validate system operability. In the first part of 2012, the commissioning of systems at St. Lucie Unit 1 proved to be more difficult than expected, in large part due to the complexities of so much new equipment and material installed at the site. As a result, engineers and craft personnel were needed to remain at that site longer than planned to ensure appropriate unit startup, contributing to 2012 cost increases. This complexity is described in Exhibit TOJ-7.

Q. Please describe the St. Lucie Unit 2 EPU implementation outage that was completed in 2012.

A. St. Lucie Unit 2 completed its final EPU outage in November. St. Lucie Unit 2 returned to service with the final 100% power uprate condition providing a total increase of 132 MWe for FPL's customers. In total, the work for the St. Lucie Unit 2 outage required the following:

- Augmented staff of 1,561 additional people at its peak;
- Approximately 9,200 individually planned, scheduled, and monitored activities supporting 1,494 work packages; and

- Approximately 1,279,000 man hours of work.

Q. Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on St. Lucie Unit 2?

A. Yes, but not nearly to the extent experienced at St. Lucie Unit 1. FPL was able to utilize the experience gained at St. Lucie Unit 1 to enhance the St. Lucie Unit 2 outage and on-line engineering designs, work packages, and planning and scheduling. FPL and its vendors performed this work to implement lessons learned in advance of the St. Lucie Unit 2 outage, thus requiring more staffing than planned during that pre-outage period. As a result, the St. Lucie Unit 2 EPU implementation outage was completed in less time and at a lower cost than the St. Lucie Unit 1 EPU implementation outage: the St. Lucie Unit 2 EPU outage was completed 25% faster and at an 18% lower cost than the Unit 1 outage.

Q. Please explain some of the lessons learned that improved cost and schedule performance at St. Lucie Unit 2.

A. FPL and Bechtel made significant work package enhancements based on difficulties experienced in the implementation of similar modifications at St. Lucie Unit 1 by incorporating changes into the modification designs. Additionally, FPL and Bechtel improved the "field change process," whereby the need for an engineered solution is discovered in the field and incorporated into the modification designs. The improved, streamlined process reduced the number of reviews and approvals required for field engineering. FPL also created a dedicated Instrumentation & Control (I&C) team to manage trouble shooting activities that are discovered during unit start up, rather than relying on the plant I&C team, for whom work assignments can change daily.

Q. Please describe the Turkey Point Unit 3 EPU implementation outage that was completed in 2012.

A. Turkey Point Unit 3 completed its final EPU outage in September. The unit returned to service with the final 100% power uprate condition providing approximately 116 MWe for FPL's customers. Included in Exhibit TOJ-3, pages 4 to 49, are photographs showing the site and the worker parking, portable and permanent cranes needed to support the project, the minimal lay down areas which increased the complexity and logistics of the project, and examples of the large pieces of equipment and cranes that are required to support the increased power production. In total, the work for the Turkey Point Unit 3 outage required the following:

- Augmented staff of 3,480 additional people at its peak;
- Approximately 19,000 individually planned, scheduled, and monitored activities supporting 2,900 work packages; and
- Approximately 4,458,130 man hours of work.

Q. Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on Turkey Point Unit 3?

A. Yes. As was the case with the St. Lucie Unit 1 outage, the Turkey Point Unit 3 EPU modifications were "first time evolution" major modifications, requiring the removal of interferences, at an operating nuclear power plant with even less space (than St. Lucie) in which to do the work. During component removal, discovery required more engineering design, scheduling and planning, constructability reviews, and ultimately more time than planned to perform the required modifications. FPL also worked to ensure nuclear regulatory requirements, including safety considerations, were satisfied. Two examples of modifications that encountered these types of complexities – the Control Room Emergency Ventilation System (CREVS) and the Control Room Emergency Filtration System (CREFS) modification and the main condenser replacement – are described below.

CREVS/CREFS: The NRC-mandated modifications to the CREVS/CREFS became very complex. This involved the installation of a hurricane-proof, tornado-proof, earthquake-proof, hardened ventilation and filtration system in an area of the plant not originally designed to meet those specifications. The purpose of the CREVS/CREFS, along with the Control Room Boundary and Control Room Envelope is to provide an acceptable environment for control room personnel and equipment such that the reactor can be safely controlled under normal conditions and maintained in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. There were several engineering design evolutions during the constructability and planning portion of the modification. For example, the modification required the replacement and redesign of structural supports associated with the CREVS/CREFS fans and relocation of existing outside air intakes. Relocation of existing air intakes then required additional seismic and missile protection design to meet safety related design requirements. Additionally, special seismic structures and heavy wall piping were used to move air from the units to the control room. But the added seismic piping supports and seismic structures that hold the ventilation fans and dampers and the filtration portion of the systems required additional planning and manpower to implement the modification. The project team had previously estimated that this NRC-required safety modification would require 11,200 man hours of engineering and 72,066 man hours of field implementation. It actually required 15,502 man hours of engineering and 218,173 man hours of field implementation.

Replacement of the Main Condenser: The main condenser is the component that condenses the 6.4 million pound mass per hour steam flow of the turbine. The condenser has approximately 55,000 tubes for cooling that is supplied by roughly 700,000 gallons of water per minute. Replacing the main condenser required far more engineering design hours, implementation time, implementation manpower, and raw materials than FPL estimated, as a result of location congestion and conditions that could not be discovered until the implementation of the modification began.

Initially, FPL planned to use portable cranes to move the old condenser out and the new condenser into place. However, it was later determined that there was simply not enough land to stage a portable crane of sufficient capacity or maneuver the crane's loads. Accordingly, a specialty track crane was designed. This required the installation of micro piles for one rail, and the use of one of the turbine building crane rails for the other. The scheduling of crane use was critical to ensuring worker safety, as both the turbine building crane and the condenser crane could not be used at the same time.

Additionally, the foundation of the condenser could not be assessed until the old condenser was removed. Upon removal, it was determined that it was necessary to upgrade the foundation steel and concrete for the new condenser, which required additional time for engineering design, planning, and scheduling, as well as additional commodities. The discovery of the need to upgrade spargers that distribute steam as it enters the condenser also required more engineering design, materials, planning, and implementation, all of which added to the complexity of the condenser work. The estimated engineering and field implementation was 215,900 man hours. The condenser replacement including the temporary specialty crane took a total of approximately 368,090 man hours of engineering and field implementation. Additional examples of complexity at Turkey Point Unit 3 are included in Exhibit TOJ-7.

Q. Please describe the final EPU implementation outage, at Turkey Point Unit 4, which FPL began at the end of 2012.

A. The Turkey Point Unit 4 final EPU outage began in November 2012 and is scheduled to complete in the first quarter of 2013. Turkey Point Unit 4 will return to service with the final 100% power uprate condition providing approximately 116 MWe for FPL's customers. Through the end of 2012, the work for the Turkey Point Unit 4 outage had required the following:

- Augmented staff of 3,984 additional people at its 2012 peak;

- Approximately 15,010 individually planned, scheduled, and monitored activities supporting 3,400 work packages; and
- Approximately 1,710,000 man hours of work as of December 31, 2012 (out of an expected more than 2,000,000 man hours).

Q. **Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on Turkey Point Unit 4 in 2012?**

A. Yes. However, not nearly to the extent experienced at Unit 3. FPL utilized the experience gained at Turkey Point Unit 3 to enhance the Turkey Point Unit 4 outage engineering designs, work packages, and planning and scheduling. This work was performed in advance of the Turkey Point Unit 4 outage, thus requiring more staffing than planned during that pre-outage period. As of December 31, 2012, 56 days into the ongoing Turkey Point Unit 4 outage, the forecast duration of the Unit 4 outage was 33% better than the Turkey Point Unit 3 outage, and the forecast cost was 20% better than the cost of the Unit 3 outage.

Q. **Please explain some of the lessons learned that improved cost and schedule performance at Turkey Point Unit 4.**

A. FPL incorporated design changes discovered to be needed during the Unit 3 implementation into the modification designs and work packages for Unit 4. Additionally, FPL assigned a logistics manager to consolidate facilities and warehouses used to handle the large quantities of materials housed on site for the project, reduce support staff, and reorganize the manner in which the EPU materials are laid out based on lessons learned at Unit 3. Finally, FPL decided to redistribute a portion of the EPC work scope among four major vendors, as described in more detail below.

Q. Did FPL begin performing EPU project close out activities in 2012?

A. Yes. Some of the activities included in the project closeout are engineering change package closeout, final safety analysis and design basis document updates, closeout of EPU work packages, evaluation of preventive maintenance requirements for new and modified components and development of preventive maintenance work orders, procedure revisions, identification and purchase of spare parts, completion and testing of the control room simulator changes, closeout related purchase orders and contracts, demobilization, and restoration of site facilities and asset recovery.

Q. Please describe FPL's efforts to manage vendor costs in 2012.

A. FPL diligently managed its major vendors, including Bechtel, its EPC vendor, to ensure the costs expended for the assigned scopes of work were reasonable and appropriate. For example, FPL conducted senior-level management meetings in Frederick, Maryland at Bechtel's headquarters to address then-current trends and metrics. FPL also required that its vendors provide detailed schedules and detailed metrics for productivity and commodities, and diligently monitored compliance with those metrics. Feedback was provided through daily focus meetings during outages with major contractors to evaluate earned value and cost performance, daily work plans, and any impacts to schedule and cost. Additionally, FPL held project integration meetings with major contractors generally weekly to discuss schedule compliance of work activities, organization and management issues, and safety issues. FPL leveraged performance in each of these areas to negotiate concessions from Bechtel and other major vendors, resulting in a total reduction in EPU costs in 2012 of $63 million.

At St. Lucie, FPL awarded certain scopes of EPC work to Shaw, which is an experienced nuclear industry construction and engineering firm that has a proven track record on FPL projects. At Turkey Point, given the complexity and magnitude of the work scope and lessons learned from the Turkey Point Unit 3 outage, FPL considered and analyzed a redistribution of a portion of the EPC work scope for the Turkey Point Unit 4 outage. The effort included soliciting competitive bids for the Unit 4 spent fuel pool cooling work and for specific turbine building piping and instrumentation, reviewing technical and commercial terms, negotiating cost and schedule details of work scopes inside the Unit 4 reactor containment building, and comparing commercial proposals with the associated Unit 3 actual costs. As a result, the project execution plan for the Unit 4 EPU outage was restructured and work scope was redistributed among four vendors, including the original EPC contractor. This change allowed the EPC contractor to focus on execution of the remaining EPU Modifications while specialty contractors focused on specific scopes of work in a specific region of the plant. Bechtel retained the EPC implementation scope on the secondary side of the plant, while Shaw's scope within the radiological control area was expanded. Weldtech's scope was expanded during the Unit 3 outage, and it was expanded further for Unit 4. Additionally, PCI – a vendor with a proven track record on FPL radiological scopes of work – was hired to perform a limited scope of work within the Unit 4 radiological control area. These work assignments were made as part of FPL's continuing efforts to control costs and ensure the successful completion of the fourth and final EPU outage.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. How was the vast amount of project planning, execution, and contractor oversight described above managed by FPL?

A. FPL had robust project planning, management, and execution processes in place. These efforts were spearheaded by personnel with significant experience in project management within the nuclear industry. Additionally, the EPU project used guidelines and Project Instructions to assist project personnel in the performance of their assigned duties. Exhibit TOJ-10, EPU Project Instructions (EPPI) Index as of December 31, 2012, is provided to illustrate the types of instructions that were used.

Q. Please describe the EPU project management organization during 2012.

A. FPL had a dedicated Nuclear Power Uprate team within the nuclear fleet that was responsible for monitoring and managing the Uprate Project, schedule, and costs. In addition to centralized project oversight, there was an EPU Site Implementation Owner, 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 was appropriate as the EPU Project carried out the implementation phase at each of the sites to better integrate EPU activities with plant operating and outage activities. Each site organization's manpower size was adjusted as the execution, power ascension testing, and turnover to operations completed and project close out began.

There was also a separate Nuclear Business Operations (NBO) group that provided 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 provided accounting and regulatory oversight for the EPU Project. It was independent of the EPU Project team and reported to the Vice President Nuclear Finance. NBO's primary responsibilities included:

- 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 Internal Order 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 various corporate 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 2012?

A. FPL utilized a variety of mutually reinforcing schedule and cost controls and drew 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 existed a Controls Group. The Controls Director provided functional leadership, governance, and oversight. Each site had a dedicated EPU Project Controls group lead by a Project Controls Supervisor. The site Project Controls group provided 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-11, EPU Project Reports 2012, lists many of the reports that were a direct result of the information the Controls group provided, analyzed and produced.

FPL's efforts to meet the desired completion date of each uprate was tracked through the use of Primavera P-6 scheduling software, enabling FPL to track the schedule daily and update the schedule weekly. This allowed Project Management to monitor and report schedule status on a periodic basis. Updates to the schedule and scope of the project were made as such changes were approved by management. FPL's use of this scheduling software system allowed 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 identified a scheduled milestone date that may have a high probability of being missed, a mitigation plan was 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 were 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 received contractor invoices and forwarded them to technical representatives to ensure the scope of work had been completed and the deliverables had been accepted. For fixed-price contracts, the Cost Engineer matched the invoice amount to the contract amount and the deliverable work received from the subject matter expert, which was then sent to the appropriate personnel for approval and payment. The Cost Engineer also prepared accruals and reviewed variance reports monthly for each of the sites, to monitor and document expenditures and commitments to the approved budget. The Project Controls group operated in a transparent manner and its accountability was clear in providing sound analysis based on all available cost and schedule information at their disposal.

Q. What periodic reviews were conducted in 2012 to ensure that the project and key decisions were appropriately analyzed, reviewed and approved at the appropriate management levels?

A. Regularly scheduled meetings were held to help effectively manage the Uprate project and communicate the performance of the project in terms of quality, schedule and costs. These included 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;
- Monthly meetings with the Chief Nuclear Officer; Vice President, Power Uprate; Implementation Owners; and other project leaders to review

project progress and work through any identified risks to schedules or costs;

- Quarterly FPL Executive Steering Committee presentations on the status of the project;
- Routine Project Meetings involving FPL and individual major vendors to discuss project schedules and challenges; and
- Quarterly Project Meetings involving FPL and its major vendors to discuss strategies to help improve management of risk areas.

The EPU Project also produced several reports. Exhibit TOJ-11, EPU Project Reports 2012, is a listing of reports generated by the project during 2012 with a brief description, the periodicity, and the intended audience of each report. Generally, the project reports provided 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 assisted in the overall management of the EPU project.

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

A. FPL's risk management process was governed by project instruction EPPI-340, EPU Project Risk Management Program. FPL's risk management process was used to identify and manage potential risks associated with the Uprate. A Project Risk Committee, consisting of site project directors and subject matter experts, reviewed and evaluated initial cost and schedule projections and any potential significant variances. This committee enabled senior managers to critically assess and discuss risks faced by the EPU project from different departmental perspectives. The committee also ensured that actions were taken to mitigate or eliminate identified risks. When an identified risk was evaluated as high, a risk mitigation action plan was prepared, approved, and executed. The high risk item was monitored through this process until it was reduced or eliminated. Additionally, an EPU Project Risk Management report was 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 ensured continuous, vigilant identification of and response to potential project risks that could pose an adverse impact on the cost or schedule performance of the project.

Q. Please describe the risk management process as it applied to operational risk.

A. EPU project work was performed during normal plant operations and during planned refueling outages that were adjusted and extended in duration in order to permit uprate work to be performed. The amount of work that could be safely performed during these plant conditions was 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 was required to ensure the plant was operated in accordance with applicable NRC regulatory and plant technical specification requirements. This required proper sequencing of work activities that could be safely performed during normal plant operations or those that needed to be performed during planned refueling outages, including work activities that could be safely performed in parallel and those that needed to be performed in series. This operational risk management accomplished two major objectives: first was to ensure the equipment was in a state that makes it safe for workers to perform the work, and second was to ensure that the plant systems and components were properly maintained as required for public health and safety. This operational risk management through the careful planning, scheduling, and execution of work activities added 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 project in 2012.

A. The contractor selection procedures that applied to the Uprate project are found in NEE-PRO-1460, Purchasing Goods and Services-Policy and Definitions and its series of procurement procedures and Nuclear Fleet Guideline BO-AA-102-1008, Procurement Control. Additionally, the EPU project had previously developed an EPPI, and as explained in the EPPI procedure, the standard approach for the EPU project in the procurement of materials or services with a value in excess of $25,000 was to use competitive bidding. However, the use of single source, sole source, and Original Equipment Manufacturer providers was also necessary in certain situations. It is logical that the use of single and sole source procurements increased as the project entered the final implementation stages. For example, many of the contracts that were competitively bid and awarded were given work scope additions through the single source procurement process. Typically, it was not in the best business interest of FPL to contract with another vendor when security screening, site specific training, and training in policies, programs, procedures, and work processes were already established for vendors with rates that had previously been determined to be competitive and reasonable. The benefits of this included cost savings in mobilization, security screening, site specific training, site familiarity, and the important aspects of FPL's expectations for a safety conscious work environment. FPL's policies required proper documentation of justifications and senior-level management approval of single or sole source procurements.

FPL maintained its focus on the process of documenting and approving single and sole source procurements, to ensure compliance with BO-AA-102-1008, EPPIs and to facilitate review by third parties who are not directly involved in the nuclear procurement process. The single source justification (SSJ) expectations were included in appropriate project instructions, and all new applicable personnel assigned to the EPU Project were required to review and understand the SSJ expectations.

With respect to vendor management, the EPU Project Directors at each site ensured vendor oversight was provided by the experienced Project Managers, the Site Technical Representative, and Contract Coordinators. Together, these representatives provided management direction and coordinated vendor activity reviews while the vendors were on site. The Contract Coordinators verified the vendor had met all obligations and determined whether any outstanding deliverable issues existed using a Contract Compliance Matrix. In addition to assisting with the development and administration of contracts, Nuclear Sourcing and Integrated Supply Chain groups completed updates as necessary to a Project Contract Log and reported the status of contracts to Project Management. EPU management also held routine meetings with vendors' senior management as previously discussed.

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

A. FPL structured 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 had several types of contracts available depending on how well the scope of work and the risk associated with the work scope could be defined. Fixed price or lump sum contracts were used where project work scope was well-defined and risk was limited. Project Management used time and material contracts where project work scope was not well-defined and where there was greater risk to completing the work scope. These and other contract provisions helped to ensure that the contractors performed the right work at the right time for the right price, which ultimately benefits FPL's customers.

Additionally, as described above, FPL made decisions in 2012 to redistribute EPC scope to obtain greater cost and schedule certainty. This is reflective of the type of careful and strategic vendor management that FPL employed.

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. 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 2012 – a financial audit and an internal controls audit. The 2012 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 2012 EPU project management controls. The results of this review are presented through the testimony of Mr. John Reed, the Chief Executive Officer of Concentric Energy Advisors. Burns and Roe Enterprises, Inc. (BREI) was also engaged to review the prudence of FPL's management of the EPU project activities in 2012. The results of this review are presented through the testimony of Mr. Albert Ferrer, Vice President of BREI.

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

A. Yes. Experis, formerly Jefferson Wells, is performing an audit of 2012 expenses at Internal Audit's direction. Specifically, the Experis audit focuses on ensuring that costs charged to the EPU project are for the EPU project and are recorded in accordance with FPSC Rule 25-6.0423, and includes independent testing of expenses charged to the EPU project for the period January 1, 2012, to December 31, 2012. FPL expects this audit to be completed in the second quarter of 2013, at which time the results will be available to the Commission, Commission staff, and other parties.

"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, recoverable O&M expenses, and partial-year revenue requirements for items placed in service are requested for recovery for the EPU Project, 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 Uprate 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 were performed, the need for additional modifications or replacements necessary for the Uprate project was identified. FPL's 2012 EPU activities, and their associated costs, were "separate and apart" as required by the Nuclear Cost Recovery process.

2012 CONSTRUCTION COSTS

Q. What type of costs did FPL incur for the Uprate project in 2012?

A. As indicated in Exhibit TOJ-1, Schedule T-6 and T-4, and summarized on Exhibit TOJ-12, Summary of 2012 EPU Construction 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 described previously. Each category reflects some variance against what was estimated earlier in 2012.

Q. Please describe the costs incurred in the License Application category and the variance, if any, from the 2012 actual/estimated costs in this category.

A. Licensing Costs in 2012 consisted primarily of charges for contractor services rendered in supporting preparation, review, and NRC approval of the EPU LARs and fees paid to the NRC for their review. The primary contractors were Westinghouse, Areva, and Shaw Stone & Webster. FPL incurred $50.5 million in this category in 2012, which was $24.5 million more than the actual/estimated amount. This variance was primarily attributable to (i) additional NRC-required engineering analyses and evaluations, such as those due to industry bulletins on accelerated steam generator tube wear, the Westinghouse fuel model, other balance of plant modifications, and setpoint changes; (ii) increased fees paid to the NRC due to its extended review time; (iii) increased vendor costs due to the NRC's extended review time; and (iv) the reclassification of costs for the "umbrella modifications" (the engineering change modification at each unit that implements the NRC approved License Amendment) from the Power Block Engineering, Procurement, etc. category to the License Application category.

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 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 $30.5 million in this category in 2012, which is $5.8 million more than the actual/estimated amount. This was primarily attributable to the need to manage and oversee engineering design scope growth and the EPC and other contractors' engineering and implementation efforts for the St. Lucie and Turkey Point 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. All permits applicable to the EPU Project were approved in 2011. Accordingly, there were no costs incurred by the EPU Project in the Permitting category in 2012.

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, by the EPU central organization, and by non-EPU organizations such as NBO, New Nuclear Accounting and Regulatory Affairs. FPL incurred $57.1 million in this category in 2012 which was $4.8 million more than the actual/estimated amount. This was primarily attributable to an increase in FPL project and construction management oversight of the EPC and other vendors caused by scope growth, causing increased engineering design and implementation work, examples of which are provided above in the explanation of the various 2012 outages.

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 and other vendors for engineering, procurement, and construction resources that supported the successful completion of the EPU outages at St. Lucie Units 1 and 2, Turkey Point Unit 3, and the first two months of the Turkey Point Unit 4 outage; the continued engineering efforts to prepare for the EPU implementation 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 and valves required to support the uprate conditions.

FPL incurred $1,252 million in this category in 2012, which is $296.7 million more than the actual/estimated amount. The cost variance is the result of implementing first time evolution modifications, described in more detail above and in my Exhibit TOJ-7, which resulted in more design engineering, more implementation work scope requiring more craft labor and field non-manual support, longer than estimated installation durations which included planning, scheduling, and execution of the modification activities, and more commodities than previously estimated.

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 and simulator upgrades required to reflect the uprate conditions. FPL incurred $1.7 million in this category in 2012. This represents $0.6 million more than the actual/estimated amount. The variance is primarily attributable to additional work scope that was determined to be necessary to complete the simulator upgrades.

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

A. Recoverable O&M expenses in 2012 were $7.8 million. This represents a variance of $7.5 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, modifications that did not meet the capitalization criteria were included in this category along with O&M EPU equipment inspections and obsolete inventory write-offs. The variance is primarily attributable to fewer obsolete inventory write-offs than estimated for 2012.

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

A. Transmission Costs were $29.7 million in 2012, which is $2.3 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 installation of the new main transformer at St. Lucie Unit 2 taking longer than estimated. However, FPL was able to obtain cost savings on the bidding and purchase of major substation material and substation construction labor contracts, minimizing the variance in this category.

Q. Were FPL's 2012 EPU expenditures prudently incurred?

A. Yes. FPL incurred costs of approximately $1,429 million in 2012. FPL's actual 2012 costs were greater than its previous estimate for the reasons described above, and are primarily attributable to the human capital necessary to design and implement the required modifications needed to support the EPU; increased engineering analysis vendor costs and NRC costs due to the extended NRC reviews of the license amendment requests; increased work scope for design modification engineering; and increased modification implementation time due to increased work scope and constructability complexities.

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 2012 EPU management decisions were well-founded and prudent. All costs incurred in 2012 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

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 130009-EI

May 1, 2013

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, 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. I filed testimony on March 1, 2013, discussing the Extended Power Uprate (EPU or Uprate) project activities and costs in 2012. The purpose of this testimony is to provide information on FPL's EPU project activities and costs in 2013. There will be no EPU costs in 2014.

Q. What is the current status of the EPU project?

A. The status of the EPU project can be summarized as follows:

- The uprates of the reactors are complete;
- The project is in the close-out phase; and
- The project met its goal of providing about 400 megawatts (MWe) of fuel diverse generation for FPL's customers by 2012, and is exceeding

the goal by providing a total of at least 512 MWe in 2013. This is shown on Exhibit TOJ-14.

Q. Has the EPU project been recognized for its performance?

A. Yes. On March 21, 2013, the Nuclear Energy Institute (NEI) notified NextEra Energy, Inc. that the Nuclear Fleet EPU Project Team will receive a 2013 Top Industry Practice (TIP) Award. This is a considerable honor for the thousands of people who have worked hard on the project here in Florida, because the TIP Awards Program recognizes the very best and most innovative work in the nuclear industry. Project aspects evaluated for the TIP award include nuclear safety, cost saving impact, innovation, productivity, and transferability of these various processes to other projects.

The NEI is the policy organization of the nuclear energy and technologies industry. The NEI fosters and encourages the continued safe utilization and development of nuclear energy to meet the nation's energy, environmental, and economic goals and supports the nuclear energy industry in both national and global policy-making processes. NextEra Energy, Inc. is one of 350 members in 15 countries.

PROJECT OVERVIEW

Q. How is the EPU project benefiting customers?

A. The EPU project substantially improves FPL's electric system fuel diversity, electric reliability and environmental footprint, while saving billions of dollars in fossil fuel costs. The EPU project:

- Provides estimated fossil fuel cost savings for FPL's customers of more than $100 million in the first full year of operation;
- Provides estimated fossil fuel cost savings for FPL's customers of about $3.4 billion over the life of the plants;
- Increases FPL's nuclear generating capacity by about 17%;
- Reduces FPL's reliance on natural gas by more than 4% beginning in the first full year of operation, providing an important hedge against volatile natural gas prices;
- Adds to Florida's energy security because it does not depend on fuel delivery through Florida's only two natural gas pipelines;
- Provides a total amount of energy that is equivalent to the usage of approximately 326,000 residential customer households each year;
- Reduces annual fossil fuel usage by the equivalent of almost 7 million barrels of oil or 43 million mmBTU of natural gas annually;
- Reduces CO_2 emissions generated in making electricity to serve FPL's customers by 33 million tons over the life of the plants; and

- Enhances grid stability and electric service reliability by making more electricity close to where more electricity is used – in Southeast Florida.

The quantifications of these benefits are set forth in FPL Witness Dr. Sim's testimony and Exhibit SRS-9. These benefits are also presented in my Exhibit TOJ-16.

Q. Please expand on the final benefit you listed, the enhancement of grid stability and electric service reliability.

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. The EPU project's impact on the Southeastern area is presented in Exhibit TOJ-17.

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

A. Yes. FPL's long-term investment in the EPU project has been implemented by employing thousands of people at a time when jobs matter a great deal. As summarized in Exhibit TOJ-18, EPU project staffing ramped up beginning in 2008 and reached a peak in 2012. Project staffing is now ramping down through 2013 and project completion. This extensive workforce included thousands of professional, technical, and administrative workers, of which approximately 50% were Floridians. Employment of these workers represented a large portion of FPL's total actual investment in 2012 and 2013.

Q. How is the EPU project delivering 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 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 more than projected over the next 20 years, customers would save even more money due to the EPU project. 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.

The EPU project's benefits have been achieved consistent with the Florida Legislature's intentions in encouraging investment in additional nuclear power, pursuant to the Nuclear Cost Recovery law passed in 2006. In fact, all these benefits would not have been possible without the Nuclear Cost

Recovery law and rule. Exhibit TOJ-19 shows the policy considerations that drove the Nuclear Cost Recovery law and the delivery of the EPU nuclear MWe, consistent with those policy considerations, just six years later.

Q. Please describe the level of effort that the EPU project required.

A. The EPU project and the effort that it required were enormous. FPL and its contractors employed thousands of qualified people to complete the largest U.S. nuclear project since new plants were constructed decades ago. Including the engineering design process, the EPU work required an augmented staff of approximately 4,000 additional people at its peak and over 58,000 individually planned, scheduled, and monitored activities supporting approximately 10,600 work packages. The EPU project also required more than 15,500 pipe welds, 38,000 feet of electric wiring conduit, 288,500 feet of electrical cable, and 34,500 electrical terminations.

Q. Did FPL encounter challenges on the project?

A. Yes. The EPU project posed 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. All of the EPU work was conducted on four operating nuclear units with live steam, electrical, and nuclear fuel equipment and systems. FPL efficiently managed all of this work in a way that maximized the benefits of the EPU project for FPL's customers and in a manner that maintained nuclear and industrial safety.

Each of the four major EPU outages completed successfully in 2012 and 2013 experienced engineering design scope growth and construction complexities, mainly due to the fact that many of the activities performed were first time implementation evolutions. Examples of the scope growth and complexities encountered were detailed in my Exhibit TOJ-7, attached to my March 1, 2013 testimony. However, the experience and knowledge gained from the St. Lucie Unit 1 EPU outage was applied to the St. Lucie Unit 2 EPU outage, which resulted in the Unit 2 outage being completed 25% faster and at an 18% lower cost than the Unit 1 outage. Similarly, the experience and knowledge gained from the Turkey Point Unit 3 EPU outage was applied to the Turkey Point Unit 4 EPU outage which resulted in the Unit 4 outage being completed 15% faster and at a 21% lower cost than the Unit 3 outage. Such reductions in time and money, which were achieved at both FPL nuclear plants during the EPU project, are clear demonstrations of FPL's ability to capture and implement opportunities for improvement, an ability which is also considered by energy and construction industry professionals to be a hallmark of strong project management.

Q. Please describe the nuclear and industrial safety performance of the EPU project.

A. Nuclear and industrial safety is central to everything we have done on the EPU project. Nuclear safety was successfully ensured at every step. With the project now in its wrap-up phase, FPL is able to provide overall project safety information, which is shown in Exhibit TOJ-20. FPL, its workers and contractors do not take for granted that FPL's safety record on the EPU project each year and in total was far better than both the 2011 utility industry average and the 2011 construction industry average (the most recent year for which this industry data is available). Excellent project safety is another factor considered by utility and construction industry professionals to be a hallmark of strong project management.

2013 PROJECT ACTIVITES

Q. Please discuss the completion of the Turkey Point Unit 4 EPU outage in 2013.

A. The final EPU outage at Turkey Point Unit 4 was successfully completed in April, 2013 with an increased capacity of approximately 116 MWe of additional nuclear power for FPL's customers. In total, the Turkey Point Unit 4 outage required the following:

- Augmented staff of 2,854 at its peak;
- Approximately 15,000 individually planned, scheduled, and monitored activities supporting 3,400 work packages; and
- Over 3 million man-hours of work.

A diagram of this outage work is attached as Exhibit TOJ-21.

Q. Are EPU systems going into service in 2013?

A. Yes. Exhibit TOJ-22 lists the EPU project systems and components that have been or will be placed into service in 2013.

Q. What types of activities remain in 2013?

A. During the remainder of 2013:

- Final adjustments to components and systems will be completed. These activities include but are not limited to adjustments to process instrumentation loops to optimize performance, enhancements to the spent fuel pool handling machines, and ensuring necessary spare parts are available for the newly installed EPU components;
- Engineering design documents will be updated in accordance with regulatory requirements and modification packages will be closed;
- EPU will remove project support structures and facilities and restore site conditions. This includes the removal from the site of temporary structures used by the EPU project, restoration of permanent structures modified for EPU project use, and removal of fabrication workshops used for the EPU project;
- Salvage recovery will be completed;
- Vendors will be demobilized;
- EPU project contracts will be closed; and
- The project will be de-staffed in accordance with the project close-out plans.

Exhibit TOJ-23 is a list of EPU project work activities.

Q. Please describe the cost recovery process with respect to FPL's 2013 EPU project costs.

A. FPL expects its total 2013 EPU costs to be about $243 million. 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 2013 carrying charges, O&M expenses, and partial-year revenue requirements of approximately $11 million for the EPU project through the Nuclear Cost Recovery Clause (NCRC) in 2014.

Q. How do FPL's 2013 EPU costs contribute to FPL's NCRC request for 2013?

A. The total Company request of approximately $28 million in 2014 includes both EPU cost recovery and Turkey Point 6 & 7 cost recovery, as described by FPL Witness Powers. This equates to a residential customer monthly bill impact of $0.30 per 1,000 kWh. This is a reduction of more than 80% of FPL's currently authorized nuclear cost recovery amount, and lower by $1.35 per 1,000 kWh. Exhibit TOJ-24 shows FPL's total investment versus the clause recovery amount and Exhibit TOJ-25 shows how small the NCRC component is of a typical residential customer's overall bill.

TRUE-UP TO ORIGINAL COST AND UPDATED COST ESTIMATE RANGE

Q. Did FPL prepare a true-up of the total project costs through the current reporting period?

A. Yes. Exhibit TOJ-13 includes the True-up to Original (TOR) Schedules that compare the current actual/estimates to FPL's originally filed project costs. The 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 Florida Public Service Commission's (FPSC's) direction in Order No. PSC-09-0783-FOF-EI, FPL has revised its non-binding cost estimate for the EPU project. The 2013 non-binding cost estimate is $3,398 million, including transmission and carrying costs, as shown on the Nuclear Filing Requirement (NFR) Schedules included in Exhibit TOJ-13. As in prior years, FPL's non-binding cost estimate includes an estimate for the net book value (NBV) of plant that will be retired due to the EPU project. There are no NCRC charges associated with this NBV of retirements estimate. FPL's non-binding cost estimate reflects the increased scope that was necessary to support Nuclear Regulatory Commission (NRC) requirements, design evolution, and construction and implementation logistics which were encountered in 2012 and discussed in detail in my March 1, 2013 testimony and Exhibit TOJ-7.

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

A. The process to revise FPL's non-binding cost estimate began with an accounting of actual project costs as of the end of February 2013. Then, a forecast of costs needed to complete the Turkey Point Unit 4 EPU outage and 2013 close-out activities was developed in March and April 2013. These forecasted close-out costs were based on the experience already gained through St. Lucie close-out activities that are ongoing.

Q. Does the revised non-binding cost estimate reflect any concessions from vendors?

A. Yes. The 2012 price reductions and concessions from FPL's major EPU vendors amounted to $63 million, and were discussed in my March 1, 2013 testimony. The price reductions and concessions from the project's major suppliers provided additional offsets as work scope increased in 2012 and 2013, for a total reduction of approximately $77 million.

Q. Why is the EPU non-binding cost estimate higher than last year's non-binding cost estimate?

A. This estimate reflects the increased scope that was necessary to support NRC regulatory requirements, design evolution, construction, and implementation logistics which were required in 2012 and discussed in detail in my March 1, 2013 testimony and Exhibit TOJ-7. Additionally, the estimate reflects some variances to FPL's projected 2013 costs for which FPL is providing actual/estimated information at this time. FPL's projected 2013 costs were developed in early 2012, and accordingly, did not reflect the vast amount of information and lessons learned in the execution of the uprate work during

2012. 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. The EPU project required many more activities, which required more people, and a larger organization to manage all the work.

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, 2013 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 2013.

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 2013 actual/estimated costs are reasonable?

A. Yes. The EPU project management processes are regularly 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. Additionally, FPL uses change management plans to move the project into the project close-out. This change management plan provides the guidance and reporting requirements to close out the EPU project documents, contracts, asset management and appropriate turnover to station management.

2013 ACTUAL/ESTIMATED CONSTRUCTION ACTIVITIES AND COSTS

Q. Please summarize the activities for which FPL is incurring costs in 2013.

A. In 2013, FPL completed the second major EPU outage at Turkey Point Unit 4, adding approximately 116 MWe for a total EPU project electrical output increase of at least 512 MWe. During the remainder of 2013, FPL will be closing out the EPU project. These activities include ensuring equipment and systems are operating efficiently and as designed, updating the design calculations and documents and closing the engineering design packages, stocking spare parts for the newly installed equipment, and completion of the salvage recovery portion of the project, and contract close-out.

Q. Is FPL projecting any 2014 EPU costs?

A. No. The EPU project will be complete in 2013.

Q. Please describe how FPL developed its 2013 actual/estimated costs.

A. Actual 2013 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 2013. 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 were derived from approved detailed staffing plans. Cash flows were developed for each approved position based on the expected assignment duration. The large construction related vendor forecasts were based upon previous experience, known scope(s) of work, productivity factors, and prevailing pertinent wage rates. Cash flow projections for items identified in the Risk Register were based upon anticipated engineering, material procurement, and outage implementation time horizons.

Q. **Did FPL make any adjustments to its Actual/Estimated (AE) NFRs?**

A. Yes. As mentioned in my August 1, 2012 supplemental testimony filed in last year's docket, the company initiated an investigation into certain vendor costs. As a result of the investigation that occurred in 2012, approximately $1.5 million was reversed and an adjustment was reflected in FPL's March 1, 2013 Nuclear Cost Recovery filing for the EPU project. FPL has continued its investigation in 2013. As a result, FPL has reversed an additional approximately $0.9 million and an adjustment is reflected in the May 1, 2013 Nuclear Cost Recovery filing.

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

A. As indicated in Exhibit TOJ-13, Schedules AE-4 and AE-6, and summarized in Exhibit TOJ-26, costs are being incurred in the following categories: Licensing; Engineering & Design; Project Management; Power Block Engineering, Procurement, Etc.; Non-Power Block Engineering, Procurement, Etc.; EPU Recoverable O&M; and Transmission Capital. There are no Permitting costs in 2013. Please note that the dollar values in my testimony are the estimated EPU resource requirements, and do not include certain accounting adjustments made by FPL Witness Powers, unless noted otherwise.

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

A. For the period ending December 31, 2013, License Application costs are estimated to be ($126,960), due to the partial reversal of an accrual posted in 2012.

Q. Please describe the 2013 activities in the Engineering and Design category.

A. For the period ending December 31, 2013, Engineering and Design costs are estimated to be approximately $10.6 million. 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 Turkey Point Unit 4 EPU outage by Bechtel and other vendors for the EPU Project. This is approximately $4.6 million more than projected due to increased scope and design complexities.

Q. Please describe the 2013 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, 2013, Project Management costs are estimated to be approximately $19.6 million. 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 $3.8 million more than projected due to the increase in project management and oversight of the EPC and other vendors due to scope growth and the additional resources needed to complete the project.

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 estimated to be approximately $202.3 million. This is approximately $27.8 million more than projected. The primary drivers include completing long lead equipment payments that were deferred from 2012 into 2013, increased contractor labor and management costs to complete the Turkey Point Unit 4 work and increased infrastructure, and close out activities anticipated for 2012 that continued into 2013. As discussed above, these EPU activities were much more complex and required more resources than were anticipated when 2013 costs were projected in early 2012.

Q. Please describe the 2013 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 $350,646. This is $350,646 more than projected due to simulator work planned for 2012 but completed in 2013, and the restoration of site conditions.

Q. Please describe the 2013 actual/estimated recoverable O&M costs.

A. Actual/estimated recoverable O&M costs for the EPU project in 2013 are approximately $9.8 million. 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 2013. This is approximately $4.6 million more than projected due to non-capitalization of system and component inspections and modifications.

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

A. For the period ending December 31, 2013, Transmission costs are estimated to be $74,376. This amount is primarily related to costs associated with the upgrades to the main transformers and plant yard electrical components. This is $175,624 less than projected due to better-than-planned equipment availability and clearances.

Q. Are the 2013 actual/estimated costs presented in your testimony "separate and apart" from other nuclear plant expenditures?

A. Yes, the 2013 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, 2013, through engineering analyses FPL identified the major components and systems that must be modified or replaced to safely uprate the units and only those modifications were included in the EPU project. FPL has continued to carefully follow all of the safeguards in this respect, which the FPSC has previously reviewed and found to be reasonable and appropriate.

Q. Are FPL's actual/estimated 2013 EPU costs reasonable?

A. Yes. FPL's 2013 expenditures are for successfully completing the final EPU outage at Turkey Point Unit 4 and for EPU project close-out activities. 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 2013 expenditures are reasonable.

Q. Please list the exhibits you are submitting with this testimony.

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

- Exhibit TOJ-13 consists of NFR Schedules, including 2013 AE Schedules, 2014 Projection Schedules and TOR Schedules. These NFR Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and me, respectively.
- TOJ-14, EPU MWe
- TOJ-15, Top Industry Practice Award
- TOJ-16, 2013 EPU Project Benefits
- TOJ-17, Southeast Florida Reliability Impact
- TOJ-18, Workforce Summary
- TOJ-19, EPU Timeline
- TOJ-20, EPU Project Safety Performance
- TOJ-21, Turkey Point Unit 4 EPU Scope

- TOJ-22, EPU Equipment Placed in Service in 2013
- TOJ-23, EPU Project Work Activities List
- TOJ-24, FPL Investment versus Clause Recovery
- TOJ-25, Nuclear Cost Recovery Bill Impact
- TOJ-26, Summary of 2013 Extended Power Uprate Construction Costs

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 130009-EI

May 1, 2013

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, 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. I filed testimony on March 1, 2013, discussing the Extended Power Uprate (EPU or Uprate) project activities and costs in 2012. The purpose of this testimony is to provide information on FPL's EPU project activities and costs in 2013. There will be no EPU costs in 2014.

Q. What is the current status of the EPU project?

A. The status of the EPU project can be summarized as follows:

- The uprates of the reactors are complete;
- The project is in the close-out phase; and
- The project met its goal of providing about 400 megawatts (MWe) of fuel diverse generation for FPL's customers by 2012, and is exceeding

the goal by providing a total of at least 512 MWe in 2013. This is shown on Exhibit TOJ-14.

Q. Has the EPU project been recognized for its performance?

A. Yes. On March 21, 2013, the Nuclear Energy Institute (NEI) notified NextEra Energy, Inc. that the Nuclear Fleet EPU Project Team will receive a 2013 Top Industry Practice (TIP) Award. This is a considerable honor for the thousands of people who have worked hard on the project here in Florida, because the TIP Awards Program recognizes the very best and most innovative work in the nuclear industry. Project aspects evaluated for the TIP award include nuclear safety, cost saving impact, innovation, productivity, and transferability of these various processes to other projects.

The NEI is the policy organization of the nuclear energy and technologies industry. The NEI fosters and encourages the continued safe utilization and development of nuclear energy to meet the nation's energy, environmental, and economic goals and supports the nuclear energy industry in both national and global policy-making processes. NextEra Energy, Inc. is one of 350 members in 15 countries.

PROJECT OVERVIEW

Q. How is the EPU project benefiting customers?

A. The EPU project substantially improves FPL's electric system fuel diversity, electric reliability and environmental footprint, while saving billions of dollars in fossil fuel costs. The EPU project:

- Provides estimated fossil fuel cost savings for FPL's customers of more than $100 million in the first full year of operation;
- Provides estimated fossil fuel cost savings for FPL's customers of about $3.4 billion over the life of the plants;
- Increases FPL's nuclear generating capacity by about 17%;
- Reduces FPL's reliance on natural gas by more than 4% beginning in the first full year of operation, providing an important hedge against volatile natural gas prices;
- Adds to Florida's energy security because it does not depend on fuel delivery through Florida's only two natural gas pipelines;
- Provides a total amount of energy that is equivalent to the usage of approximately 326,000 residential customer households each year;
- Reduces annual fossil fuel usage by the equivalent of almost 7 million barrels of oil or 43 million mmBTU of natural gas annually;
- Reduces CO_2 emissions generated in making electricity to serve FPL's customers by 33 million tons over the life of the plants; and

- Enhances grid stability and electric service reliability by making more electricity close to where more electricity is used – in Southeast Florida.

The quantifications of these benefits are set forth in FPL Witness Dr. Sim's testimony and Exhibit SRS-9. These benefits are also presented in my Exhibit TOJ-16.

Q. Please expand on the final benefit you listed, the enhancement of grid stability and electric service reliability.

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. The EPU project's impact on the Southeastern area is presented in Exhibit TOJ-17.

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

A. Yes. FPL's long-term investment in the EPU project has been implemented by employing thousands of people at a time when jobs matter a great deal. As summarized in Exhibit TOJ-18, EPU project staffing ramped up beginning in 2008 and reached a peak in 2012. Project staffing is now ramping down through 2013 and project completion. This extensive workforce included thousands of professional, technical, and administrative workers, of which approximately 50% were Floridians. Employment of these workers represented a large portion of FPL's total actual investment in 2012 and 2013.

Q. How is the EPU project delivering 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 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 more than projected over the next 20 years, customers would save even more money due to the EPU project. 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.

The EPU project's benefits have been achieved consistent with the Florida Legislature's intentions in encouraging investment in additional nuclear power, pursuant to the Nuclear Cost Recovery law passed in 2006. In fact, all these benefits would not have been possible without the Nuclear Cost

Recovery law and rule. Exhibit TOJ-19 shows the policy considerations that drove the Nuclear Cost Recovery law and the delivery of the EPU nuclear MWe, consistent with those policy considerations, just six years later.

Q. Please describe the level of effort that the EPU project required.

A. The EPU project and the effort that it required were enormous. FPL and its contractors employed thousands of qualified people to complete the largest U.S. nuclear project since new plants were constructed decades ago. Including the engineering design process, the EPU work required an augmented staff of approximately 4,000 additional people at its peak and over 58,000 individually planned, scheduled, and monitored activities supporting approximately 10,600 work packages. The EPU project also required more than 15,500 pipe welds, 38,000 feet of electric wiring conduit, 288,500 feet of electrical cable, and 34,500 electrical terminations.

Q. Did FPL encounter challenges on the project?

A. Yes. The EPU project posed 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. All of the EPU work was conducted on four operating nuclear units with live steam, electrical, and nuclear fuel equipment and systems. FPL efficiently managed all of this work in a way that maximized the benefits of the EPU project for FPL's customers and in a manner that maintained nuclear and industrial safety.

Each of the four major EPU outages completed successfully in 2012 and 2013 experienced engineering design scope growth and construction complexities, mainly due to the fact that many of the activities performed were first time implementation evolutions. Examples of the scope growth and complexities encountered were detailed in my Exhibit TOJ-7, attached to my March 1, 2013 testimony. However, the experience and knowledge gained from the St. Lucie Unit 1 EPU outage was applied to the St. Lucie Unit 2 EPU outage, which resulted in the Unit 2 outage being completed 25% faster and at an 18% lower cost than the Unit 1 outage. Similarly, the experience and knowledge gained from the Turkey Point Unit 3 EPU outage was applied to the Turkey Point Unit 4 EPU outage which resulted in the Unit 4 outage being completed 15% faster and at a 21% lower cost than the Unit 3 outage. Such reductions in time and money, which were achieved at both FPL nuclear plants during the EPU project, are clear demonstrations of FPL's ability to capture and implement opportunities for improvement, an ability which is also considered by energy and construction industry professionals to be a hallmark of strong project management.

Q. Please describe the nuclear and industrial safety performance of the EPU project.

A. Nuclear and industrial safety is central to everything we have done on the EPU project. Nuclear safety was successfully ensured at every step. With the project now in its wrap-up phase, FPL is able to provide overall project safety information, which is shown in Exhibit TOJ-20. FPL, its workers and contractors do not take for granted that FPL's safety record on the EPU project each year and in total was far better than both the 2011 utility industry average and the 2011 construction industry average (the most recent year for which this industry data is available). Excellent project safety is another factor considered by utility and construction industry professionals to be a hallmark of strong project management.

2013 PROJECT ACTIVITES

Q. Please discuss the completion of the Turkey Point Unit 4 EPU outage in 2013.

A. The final EPU outage at Turkey Point Unit 4 was successfully completed in April, 2013 with an increased capacity of approximately 116 MWe of additional nuclear power for FPL's customers. In total, the Turkey Point Unit 4 outage required the following:

- Augmented staff of 2,854 at its peak;
- Approximately 15,000 individually planned, scheduled, and monitored activities supporting 3,400 work packages; and
- Over 3 million man-hours of work.

A diagram of this outage work is attached as Exhibit TOJ-21.

Q. Are EPU systems going into service in 2013?

A. Yes. Exhibit TOJ-22 lists the EPU project systems and components that have been or will be placed into service in 2013.

Q. What types of activities remain in 2013?

A. During the remainder of 2013:

- Final adjustments to components and systems will be completed. These activities include but are not limited to adjustments to process instrumentation loops to optimize performance, enhancements to the spent fuel pool handling machines, and ensuring necessary spare parts are available for the newly installed EPU components;
- Engineering design documents will be updated in accordance with regulatory requirements and modification packages will be closed;
- EPU will remove project support structures and facilities and restore site conditions. This includes the removal from the site of temporary structures used by the EPU project, restoration of permanent structures modified for EPU project use, and removal of fabrication workshops used for the EPU project;
- Salvage recovery will be completed;
- Vendors will be demobilized;
- EPU project contracts will be closed; and
- The project will be de-staffed in accordance with the project close-out plans.

Exhibit TOJ-23 is a list of EPU project work activities.

Q. Please describe the cost recovery process with respect to FPL's 2013 EPU project costs.

A. FPL expects its total 2013 EPU costs to be about $243 million. 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 2013 carrying charges, O&M expenses, and partial-year revenue requirements of approximately $11 million for the EPU project through the Nuclear Cost Recovery Clause (NCRC) in 2014.

Q. How do FPL's 2013 EPU costs contribute to FPL's NCRC request for 2013?

A. The total Company request of approximately $28 million in 2014 includes both EPU cost recovery and Turkey Point 6 & 7 cost recovery, as described by FPL Witness Powers. This equates to a residential customer monthly bill impact of $0.30 per 1,000 kWh. This is a reduction of more than 80% of FPL's currently authorized nuclear cost recovery amount, and lower by $1.35 per 1,000 kWh. Exhibit TOJ-24 shows FPL's total investment versus the clause recovery amount and Exhibit TOJ-25 shows how small the NCRC component is of a typical residential customer's overall bill.

TRUE-UP TO ORIGINAL COST AND UPDATED COST ESTIMATE RANGE

Q. Did FPL prepare a true-up of the total project costs through the current reporting period?

A. Yes. Exhibit TOJ-13 includes the True-up to Original (TOR) Schedules that compare the current actual/estimates to FPL's originally filed project costs. The 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 Florida Public Service Commission's (FPSC's) direction in Order No. PSC-09-0783-FOF-EI, FPL has revised its non-binding cost estimate for the EPU project. The 2013 non-binding cost estimate is $3,398 million, including transmission and carrying costs, as shown on the Nuclear Filing Requirement (NFR) Schedules included in Exhibit TOJ-13. As in prior years, FPL's non-binding cost estimate includes an estimate for the net book value (NBV) of plant that will be retired due to the EPU project. There are no NCRC charges associated with this NBV of retirements estimate. FPL's non-binding cost estimate reflects the increased scope that was necessary to support Nuclear Regulatory Commission (NRC) requirements, design evolution, and construction and implementation logistics which were encountered in 2012 and discussed in detail in my March 1, 2013 testimony and Exhibit TOJ-7.

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

A. The process to revise FPL's non-binding cost estimate began with an accounting of actual project costs as of the end of February 2013. Then, a forecast of costs needed to complete the Turkey Point Unit 4 EPU outage and 2013 close-out activities was developed in March and April 2013. These forecasted close-out costs were based on the experience already gained through St. Lucie close-out activities that are ongoing.

Q. Does the revised non-binding cost estimate reflect any concessions from vendors?

A. Yes. The 2012 price reductions and concessions from FPL's major EPU vendors amounted to $63 million, and were discussed in my March 1, 2013 testimony. The price reductions and concessions from the project's major suppliers provided additional offsets as work scope increased in 2012 and 2013, for a total reduction of approximately $77 million.

Q. Why is the EPU non-binding cost estimate higher than last year's non-binding cost estimate?

A. This estimate reflects the increased scope that was necessary to support NRC regulatory requirements, design evolution, construction, and implementation logistics which were required in 2012 and discussed in detail in my March 1, 2013 testimony and Exhibit TOJ-7. Additionally, the estimate reflects some variances to FPL's projected 2013 costs for which FPL is providing actual/estimated information at this time. FPL's projected 2013 costs were developed in early 2012, and accordingly, did not reflect the vast amount of information and lessons learned in the execution of the uprate work during

2012. 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. The EPU project required many more activities, which required more people, and a larger organization to manage all the work.

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, 2013 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 2013.

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 2013 actual/estimated costs are reasonable?

A. Yes. The EPU project management processes are regularly 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. Additionally, FPL uses change management plans to move the project into the project close-out. This change management plan provides the guidance and reporting requirements to close out the EPU project documents, contracts, asset management and appropriate turnover to station management.

2013 ACTUAL/ESTIMATED CONSTRUCTION ACTIVITIES AND COSTS

Q. Please summarize the activities for which FPL is incurring costs in 2013.

A. In 2013, FPL completed the second major EPU outage at Turkey Point Unit 4, adding approximately 116 MWe for a total EPU project electrical output increase of at least 512 MWe. During the remainder of 2013, FPL will be closing out the EPU project. These activities include ensuring equipment and systems are operating efficiently and as designed, updating the design calculations and documents and closing the engineering design packages, stocking spare parts for the newly installed equipment, and completion of the salvage recovery portion of the project, and contract close-out.

Q. Is FPL projecting any 2014 EPU costs?

A. No. The EPU project will be complete in 2013.

Q. Please describe how FPL developed its 2013 actual/estimated costs.

A. Actual 2013 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 2013. 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 were derived from approved detailed staffing plans. Cash flows were developed for each approved position based on the expected assignment duration. The large construction related vendor forecasts were based upon previous experience, known scope(s) of work, productivity factors, and prevailing pertinent wage rates. Cash flow projections for items identified in the Risk Register were based upon anticipated engineering, material procurement, and outage implementation time horizons.

Q. **Did FPL make any adjustments to its Actual/Estimated (AE) NFRs?**

A. Yes. As mentioned in my August 1, 2012 supplemental testimony filed in last year's docket, the company initiated an investigation into certain vendor costs. As a result of the investigation that occurred in 2012, approximately $1.5 million was reversed and an adjustment was reflected in FPL's March 1, 2013 Nuclear Cost Recovery filing for the EPU project. FPL has continued its investigation in 2013. As a result, FPL has reversed an additional approximately $0.9 million and an adjustment is reflected in the May 1, 2013 Nuclear Cost Recovery filing.

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

A. As indicated in Exhibit TOJ-13, Schedules AE-4 and AE-6, and summarized in Exhibit TOJ-26, costs are being incurred in the following categories: Licensing; Engineering & Design; Project Management; Power Block Engineering, Procurement, Etc.; Non-Power Block Engineering, Procurement, Etc.; EPU Recoverable O&M; and Transmission Capital. There are no Permitting costs in 2013. Please note that the dollar values in my testimony are the estimated EPU resource requirements, and do not include certain accounting adjustments made by FPL Witness Powers, unless noted otherwise.

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

A. For the period ending December 31, 2013, License Application costs are estimated to be ($126,960), due to the partial reversal of an accrual posted in 2012.

Q. Please describe the 2013 activities in the Engineering and Design category.

A. For the period ending December 31, 2013, Engineering and Design costs are estimated to be approximately $10.6 million. 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 Turkey Point Unit 4 EPU outage by Bechtel and other vendors for the EPU Project. This is approximately $4.6 million more than projected due to increased scope and design complexities.

Q. Please describe the 2013 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, 2013, Project Management costs are estimated to be approximately $19.6 million. 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 $3.8 million more than projected due to the increase in project management and oversight of the EPC and other vendors due to scope growth and the additional resources needed to complete the project.

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 estimated to be approximately $202.3 million. This is approximately $27.8 million more than projected. The primary drivers include completing long lead equipment payments that were deferred from 2012 into 2013, increased contractor labor and management costs to complete the Turkey Point Unit 4 work and increased infrastructure, and close out activities anticipated for 2012 that continued into 2013. As discussed above, these EPU activities were much more complex and required more resources than were anticipated when 2013 costs were projected in early 2012.

Q. Please describe the 2013 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 $350,646. This is $350,646 more than projected due to simulator work planned for 2012 but completed in 2013, and the restoration of site conditions.

Q. Please describe the 2013 actual/estimated recoverable O&M costs.

A. Actual/estimated recoverable O&M costs for the EPU project in 2013 are approximately $9.8 million. 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 2013. This is approximately $4.6 million more than projected due to non-capitalization of system and component inspections and modifications.

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

A. For the period ending December 31, 2013, Transmission costs are estimated to be $74,376. This amount is primarily related to costs associated with the upgrades to the main transformers and plant yard electrical components. This is $175,624 less than projected due to better-than-planned equipment availability and clearances.

Q. Are the 2013 actual/estimated costs presented in your testimony "separate and apart" from other nuclear plant expenditures?

A. Yes, the 2013 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, 2013, through engineering analyses FPL identified the major components and systems that must be modified or replaced to safely uprate the units and only those modifications were included in the EPU project. FPL has continued to carefully follow all of the safeguards in this respect, which the FPSC has previously reviewed and found to be reasonable and appropriate.

Q. Are FPL's actual/estimated 2013 EPU costs reasonable?

A. Yes. FPL's 2013 expenditures are for successfully completing the final EPU outage at Turkey Point Unit 4 and for EPU project close-out activities. 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 2013 expenditures are reasonable.

Q. Please list the exhibits you are submitting with this testimony.

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

- Exhibit TOJ-13 consists of NFR Schedules, including 2013 AE Schedules, 2014 Projection Schedules and TOR Schedules. These NFR Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and me, respectively.
- TOJ-14, EPU MWe
- TOJ-15, Top Industry Practice Award
- TOJ-16, 2013 EPU Project Benefits
- TOJ-17, Southeast Florida Reliability Impact
- TOJ-18, Workforce Summary
- TOJ-19, EPU Timeline
- TOJ-20, EPU Project Safety Performance
- TOJ-21, Turkey Point Unit 4 EPU Scope

- TOJ-22, EPU Equipment Placed in Service in 2013
- TOJ-23, EPU Project Work Activities List
- TOJ-24, FPL Investment versus Clause Recovery
- TOJ-25, Nuclear Cost Recovery Bill Impact
- TOJ-26, Summary of 2013 Extended Power Uprate Construction Costs

Q. Does this conclude your testimony?

A. Yes.

**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

In re: Nuclear Cost Recovery Clause	))	DOCKET NO. 130009-EI FILED: July 3, 2013

ERRATA SHEET

MAY 1, 2013 TESTIMONY OF WINNIE POWERS

PAGE #	LINE #	
Page 1	Line 16	Change "$28,280,172" to "$45,084,695"
Page 2	Line 10	Change "$28,280,172" to "$45,084,695"
Page 2	Line 12	Change "($1,718,507)" to "($1,726,074)"
Page 2	Line 13	Change "$5,164,762" to "$21,136,506"
Page 2	Line 14	Change "$24,833,917" to "$25,674,264"
Page 3	Line 16	Insert: • Exhibit WP-7, St. Lucie and Turkey Point Uprate Project, Incremental 2012 Plant Placed into Service as of December 31, 2012 shows the calculation of the revenue requirements related to the difference between our actual 2012 Plant Placed into Service as filed in our March 1, 2013 filing and the amount currently being recovered in base rates effective January 2, 2013 as filed in Docket No 120244-EI. • Exhibit WP-8, St. Lucie and Turkey Point Uprate Project, Actual/Estimated Net Book Value of Retirements, Removal Cost & Salvage for Plant Placed into Service in 2012 shows the calculation of the return on the difference between our 2012 actual Net Book Value of Retirements, Removal Cost and Salvage and the amount currently being recovered in base rates as filed in Docket No 120244-EI.
Page 9	Line 20	Change "$28,280,172" to "$45,084,695"
Page 9	Line 22	Change "($1,718,507)" to "($1,726,074)"
Page 9	Line 22	Change "$5,164,762" to "$21,136,506"
Page 10	Line 1	Change "$24,833,917" to "$25,674,264"
Page 14	Line 6	Change "$6,320,736" to "$22,292,480"

Page 14	Line 13	Change "$91,570,685" to "$107,542,429"
Page 14	Line 14	Change "$6,320,736" to "$22,292,480"
Page 14	Line 17	Change "$6,320,736" to "$22,292,480"
Page 14	Line 19	Change "$6,320,736" to "$22,292,480"
Page 14	Line 19	Change "$4,910,348" to "$4,912,831"
Page 14	Line 20	Change "$4,534,043" to "$4,534,025"
Page 14	Line 21	Change "($3,123,656)" to "$12,845,624"
Page 15	Line 4	Change "$20,344,266" to "$20,346,709"
Page 15	Line 7	Change "$4,910,348" to "$4,912,831"
Page 15	Line 12	Change "$9,790,528" to "$9,790,510"
Page 15	Line 12	Change "$9,611,913" to "$9,611,895"
Page 15	Line 20	Change "$4,534,043" to "$4,534,025"
Page 16	Line 2	Add after 2013, "Incremental 2012 EPU plant placed into service and carrying charges on the Actual/Estimated 2012 Net Book Value of Retirements, Removal, Salvage".
Page 16	Line 2	Change "$61,614,546" to "$77,583,826"
Page 16	Line 10	Change "$765,539,144" to "$765,692,636"
Page 17	Line 12	Insert:

Q. Please explain the revenue requirements associated with the true-up of Incremental 2012 EPU Plant Placed into Service that FPL is including in its actual/estimated EPU NFRs.

A. To properly account for the 2013 effect of truing up FPL's 2012 EPU Plant in Service, FPL has included approximately $14 million in revenue requirements in its actual/estimated 2013 EPU costs. The going-forward effect of truing up FPL's 2012 EPU Plant in Service will be reflected in FPL's fall 2013 EPU base rate increase filing.

The revenue requirement of $13,825,845 shown in my Exhibit WP-7 reflects the recovery of revenue requirements associated with FPL's actual 2012 plant placed into service not being recovered through the base rate adjustment effective January 2, 2013 (Incremental 2012 EPU Plant Placed into Service). FPL filed its Base Rate Increase request for 2012 plant placed into service on October 1, 2012 in Docket No. 120244-EI. At that time, FPL estimated that as of December 31, 2012, plant placed into service would be $1,878,131,732, Total Company, $1,794,897,191, jurisdictional, net of participants as shown on my Exhibit WP-7. FPL's T schedules filed on March 1, 2013 in this docket, show that FPL's actual 2012 plant placed into service was $1,999,281,325 Total Company, $1,913,808,590 jurisdictional, net of participants. FPL's Non-incremental 2012 Plant in Service was included in base rates effective January 2, 2013 as a result of FPL's general rate case. Excluding these Non-incremental costs as shown in my Exhibit WP-7, page 2, results in 2012 Plant in Service of $1,910,775,238, jurisdictional, net of participants. The resulting Incremental 2012 EPU Plant Placed into Service of $115,878,047, jurisdictional, net of participants as of December 31, 2012 is the basis for the calculation of the $13,825,845 in 2013 revenue requirements. The Incremental 2012 EPU Plant Placed into Service is due to more Plant in Service and Post in Service costs than had been estimated for purposes of the Base Rate Increase. FPL has included in its 2013 Actual/Estimated NFRs the revenue requirements on the 13 month average of Incremental 2012 Plant Placed into Service that is not being recovered in base rates.

Q. Please explain the carrying charges associated with the true-up of the Actual/Estimated 2012 Net Book Value of Retirements, Removal Cost and Salvage related to the 2012 EPU Plant Placed into Service.

A. FPL is including carrying charges of $1,396,293 on FPL's actual 2012 Net Book Value of Retirements, estimated Removal Cost and estimated Salvage not being recovered in the base rate adjustment effective January 2, 2013 (Actual/Estimated 2012 NBV) related to the 2012 EPU Plant Placed into Service as shown in my Exhibit

WP-8. The Actual/Estimated 2012 NBV results from the true-up of the 2012 actual retirements, estimated removal cost and estimated salvage as compared to that which is being recovered through base rates effective January 2, 2013 as approved in Docket No 120244-EI. Included in FPL's base rates effective January 2, 2013, was a net amount consisting of the net book value of retirements, removal cost and salvage of $13,509,262 on a jurisdictional, net of participants basis. The actual 2012 net book value of retirements, estimated removal costs, and estimated salvage is $26,209,670 on a jurisdictional, net of participant basis as shown in my Exhibit WP-8, page 1. The Actual/Estimated 2012 NBV is $12,700,408 and is included in WP-8. FPL has included $1,396,293 in carrying charges in its 2013 A/E NFRs for the revenue requirements not being recovered in base rates.

Page 17	Line 22	Change "$682,800" to "$1,523,146"
Page 18	Line 10	Change "$682,800" to "$1,523,146"
Page 18	Line 12	Change "$683,849" to $1,524,201"
Page 18	Line 13	Change "($1,049)" to "($1,055)"
Page 18	Line 20	Change "$10,887,829" to "$27,692,352"
Page 18	Line 22	Change "$3,884,294" to "$3,876,726"
Page 19	Line 1	Change "$6,320,736" to "$22,292,480"
Page 19	Line 2	Change "$682,800" to "$1,523,146"
Page 21	Line 22	Change "$28,280,172" to "$45,084,695"
Page 22	Line 1	Change "($1,718,507)" to "($1,726,074)
Page 22	Line 3	Change "$5,164,762" to "$21,136,506"
Page 22	Line 4	Change "$24,833,917" to "$25,674,264"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

AMENDED REBUTTAL TESTIMONY OF TERRY O. JONES

DOCKET NO. 130009-EI

JULY 26, 2013

Q. Please state your name and business address.

A. My name is Terry Jones and my business address is 700 Universe Boulevard, Juno Beach, FL 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Vice President, Nuclear Power Uprate.

Q. Have you previously provided testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses the direct testimony provided by the Office of Public Counsel's (OPC's) Witness William Jacobs.

Q. Please summarize your rebuttal testimony.

A. The Extended Power Uprate (EPU) project has been a large and complex project, involving millions of pages of data, spreadsheets, engineering drawings, schedules, work orders, and other project information. The project is coming to a successful close, presently delivering 522 megawatts electric (MWe) of incremental nuclear capacity and energy to FPL's customers. In the course of the project and the Nuclear Cost Recovery (NCR) proceeding, FPL has made all of this information available to the parties, Florida Public Service Commission (Commission) staff, and Commissioners, and has done so in a forthright and transparent manner.

Witness Jacobs's arguments stem from his repeated (and repeatedly rejected) attempt to split the EPU project into two pieces – one at St. Lucie and one at Turkey Point – when it was proposed, approved, and pursued as one project. In fact, FPL could not have delivered the over 400 MWe it was commissioned to provide by performing only half the project.

Once again, Witness Jacobs has not identified a single imprudent management action or decision in the year subject to review that caused the project costs to increase. It is clear that OPC Witness Jacobs's requested "remedy" should be rejected by the Commission.

Q. Does the Nuclear Cost Recovery process anticipate a lapse in time between the utility's pre-filed current year estimates and the hearing?

A. Yes. The Nuclear Cost Recovery Rule, Rule 25-6.0423, requires the utility to file prior-year costs by March 1st, current and subsequent year costs by May 1st, and requires the Commission to conduct a hearing and make its determinations by October 1st of each year. Obviously the utility's current and subsequent year projections reflect a snapshot in time that is clearly identified as such and then moved into the record at the time of the hearing. This is also true in the other clause dockets. OPC's witness should be familiar with the clause true-up process and appears to be blaming FPL for not perfectly predicting its costs. Of course, if any utility could do that, there would be no need for the true-up process that occurs in the following year in every clause.

Q. Please describe FPL's overall approach with respect to providing information to the Commission and to NCR parties.

A. The EPU project has always been an open book, transparent to the Commission and the parties of the NCR process. Each year FPL has provided copies of cost forecasts, monthly cost reports, monthly operating performance reports, contracts, invoices, correspondence, and many other documents requested by the parties. In 2012, FPL produced 63,906 pages of information to Commission Audit staff and 35,581 pages of information to parties in discovery. Additionally, EPU personnel including me are interviewed by Audit Staff each year. I have also been available for deposition each year. These, in addition to my testimony each year, are the numerous avenues by which the Company provides information to the Commission and parties concerning the EPU project.

Witness Jacobs's Incorrect Attempt to Evaluate Turkey Point in Isolation (Again)

Q. Witness Jacobs begins by attempting to quantify the cost of the Turkey Point portion of the EPU project and points to the differences between the Turkey Point and the St. Lucie plants. Please respond.

A. For three years now, OPC has attempted to examine the Turkey Point portion of the EPU project in isolation. For three years, I and other FPL witnesses have explained why such an exercise is inappropriate. To summarize:

- In 2007, FPL proposed and the Commission approved the EPU project as a single project to meet the need for 400 MWe by 2012.

- The objective of the project was to produce an additional 400 MWe using nuclear fuel that required four reactors to be uprated at two sites, as it could not have been done with only two reactors at one site.
- Efficiencies and cost savings have been realized in contract negotiations and through resource sharing by working the uprate of all four units as a single project.
- Since the beginning, FPL has acknowledged the differences between the Turkey Point and St. Lucie portions of the EPU project. FPL has never claimed each site would represent 50% of the project cost.
- The feasibility of the EPU project has always been based on the total cost and total benefits of the project, and not on just a portion of the project.

Dr. Sim responds to Witness Jacobs's faulty claim that the cost of the Turkey Point portion, when viewed in isolation, is "uneconomic."

Q. Has such an attempt to split the EPU project into two pieces been rejected in the past?

A. Yes. In 2011, Witness Jacobs recommended, "[t]he St. Lucie and Turkey Point projects should be looked at separately in the analysis, with a break-even cost identified for each project." (2011 NCR Hearing Transcript p. 1031) His reasoning, as summarized by the Commission, was that "the project should be broken up into two separate analyses due to the higher estimated capital costs of the Turkey Point plant portion of the uprate project" (Order No. PSC-11-0547-FOF-EI, p. 40) – the same reasoning Witness Jacobs presents this year. In 2012, Witness Jacobs recommended, "[t]he Commission should revisit the decision to permit FPL to continue to treat the economics of the EPU projects on a consolidated basis[.]" (2012 NCR Hearing Transcript, p. 1296-1297) In both cases the Commission rejected Witness Jacobs's recommendations.

Q. Did the Commission's order explain why it rejected Witness Jacobs's recommendations?

A. Yes. In 2011, the Commission concluded:

> "We agree with FPL that a separate economic analysis for each of the EPU project plant is unnecessary, and would be difficult to calculate. While a mathematical average of the benefits derived from lessons learned and equipment bulk orders can be developed, it is not known if these would have materialized if only one plant was upgraded. Therefore, completing separate analyses would incorrectly attribute to the individual plants the benefits gained from performing uprates at both plants simultaneously." (Order No. PSC-11-0547-FOF-EI, p. 40)

In 2012, the Commission rejected Witness Jacobs's attempt to split the project into two pieces for similar reasons, quoting its 2011 order. (Order No. PSC-12-0650-FOF-EI, p. 66)

Because the Commission repeatedly rejected the premise for separately analyzing the Turkey Point costs, it is wrong for Witness Jacobs to assert that knowledge of higher Turkey Point costs in 2012 would have somehow supported a different Commission conclusion on this point.

Q. Are there benefits unique to the Turkey Point portion of the EPU project ignored by Witness Jacobs?

A. Yes, the 242 additional MWe that are being provided by the Turkey Point portion of the EPU are most valuable since they are generated very near where FPL's customers have the highest demand for electricity in FPL's service territory as indicated in Exhibit TOJ-17. In addition, the Turkey Point portion of the EPU project has significantly improved FPL's grid stability and reliability, thereby further benefitting FPL's customers.

Witness Jacobs's Incorrect Criticisms Regarding Prior Testimony

Q. On page 19, Witness Jacobs criticizes your 2011 characterization of FPL's 2011 non-binding cost-estimate as "highly informed." Please respond.

A. In my July 25, 2011 rebuttal testimony, I characterized the 2011 non-binding cost estimate as "highly informed." However, Witness Jacobs has taken my statement out of context. The full context of my statement was that the 2011 non-binding cost estimate was highly informed *relative to the non-binding cost estimates of previous years*. (2011 NCR Hearing Transcript, p. 1208-1209) This was the case because FPL had achieved the completion of LAR engineering, achieved the completion of about 70% of the design engineering, and had information learned from the early stages of implementation. In April 2011, we knew what modifications needed to be implemented to accomplish the EPU project. Accordingly, I stand by my statement that the 2011 non-binding cost estimate range was "highly informed" in comparison to the previous years' non-binding cost estimate.

Exhibit TOJ-7 provides a detailed description of the complexities and discovery encountered during the 2012 EPU implementation outages.

Q. Please respond to the claim that your detailed descriptions and justifications of scope increases (and resulting cost increases) demonstrate imprudence of "failing to... accomplish advanced engineering at the outset" or incorporate an adequate contingency, at page 20.

A. These two theories were raised by Witness Jacobs in the 2011 and 2012 NCR dockets, respectively, and rejected by the Commission. As I have indicated previously on numerous occasions, the EPU project was initiated and approved to deliver approximately 400 MWe by 2012. Therefore, it was necessary to perform the project in four overlapping phases. Had the four phases been performed in series, the project would have taken much longer thus delaying the benefits to customers, and the total cost to customers would have been greater. Therefore, it was entirely prudent to complete the project in four overlapping phases and deliver the megawatts to our customers as planned.

Q. Did FPL include an adequate contingency during the course of the EPU project?

A. Yes. Throughout the EPU project, FPL has maintained a goal to provide a reasonable amount of contingency in order to control project costs. FPL believes that if a very large contingency is established, such as the level of contingency that a contractor would include in a fixed price proposal for a scope of work with many uncertainties, then the ability to control project costs would be diminished. In April 2012, FPL established a reasonable contingency of $100 million ($90 million for PTN and $10 million for PSL) with a to-go estimate of $978 million ($743 million at PTN and $235 million at PSL). Thus the total contingency was approximately 10% of the to-go estimate.

Q. Turning to 2012, Witness Jacobs states that FPL estimated it would spend $688 million on the Turkey Point portion of the EPU project in 2012, when it actually spent $975 million on the Turkey Point portion of the EPU project in 2012. Please explain the vintage of and basis for FPL's $688 million estimate.

A. My testimony filed on April 27, 2012 included Actual Estimated (AE) 2012 costs which were based on actual costs through February 2012 and estimated costs for March through December 2012. As I explained in my April 27, 2012 testimony, these costs were based on a number of forecasts. Specifically, I testified as follows:

> "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." (2012 NCR *Hearing Transcript*, p. 1059)

FPL recognizes, with the benefit of hindsight, that it underestimated its 2012 EPU costs, including those it estimated for Turkey Point. Contrary to Witness Jacobs's claim (at page 20) that I have not "justified the discrepancy" between estimated and actual 2012 costs, the reasons for the variance are fully explained in my March 1, 2013 testimony, particularly Exhibit TOJ-7, which details the numerous complexities and discovery issues encountered during EPU implementation after preparation of the April 27, 2012 filing. Additionally, approximately $75 million of the 2012 PTN EPU cost was not an increase in total project cost and was due to two accelerated vendor payments which were moved from 2013 to 2012 and were not included in the April 27, 2012 estimate of 2012 costs.

It is also important to recognize that both the $688 million figure and the $975 million figure cited by Witness Jacobs exclude removal costs, EPU recoverable O&M costs, transmission capital costs, and transmission recoverable O&M costs.

Q. **When you testified at the Nuclear Cost Recovery hearing in September of 2012, did you indicate that the $688 million estimate included in your prefiled testimony was FPL's current or final estimate of Turkey Point costs?**

A. No. To the contrary, I was very clear in indicating that total project costs – which included 2013 Turkey Point estimates – remained subject to change. Specifically, I testified as follows:

> "As I have stated before, this [non-binding cost estimate] 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[.]" (2012 NCR Hearing Transcript, p. 1078)

During cross examination, OPC specifically asked me whether the total project cost increase presented in 2012 was the "final refinement" of project costs, and I answered that it was not. (2012 NCR Hearing Transcript, p. 1351) These statements were made to communicate that project costs could increase and I believe OPC took them as such.

Q. What was the status of FPL's total project cost forecast compared to its non-binding cost estimate as of September 2012?

A. As of September 2012, FPL's total EPU project cost forecast had been increasing and remained within the non-binding cost estimate range filed on April 27, 2012. For that reason, I made it clear during the 2012 hearing that FPL's non-binding cost estimate was still subject to change, as discussed earlier in this testimony.

Additionally, during the 2012 hearing, I testified that I expected the total installed cost per kilowatt, upon completion of the EPU project, to be about the same as that reflected in the company's 2012 filing. Now that implementation work is complete, I can report that the total installed cost per kilowatt is in fact about the same as it was estimated to be last year. Using the upper end of last year's non-binding cost estimate range, the cost per kilowatt was estimated to be $6,429. Using the mid-point of the range (the cost assumed for feasibility purposes), the cost per kilowatt was estimated to be $6,224. This year, the installed cost per kilowatt is estimated to be $6,510 which is only about 1.3% higher than last year's estimate using the high end of that range, and about 4.6% higher than last year's estimate using the mid-point of that range.

Q. What is the total MWe output of the EPU project reflected in this installed cost per kilowatt calculation?

A. The EPU project is now providing 522 MWe to FPL's customers, based on recently completed testing. This reflects an additional 10 MWe as compared to my May 1, 2013, testimony, all of which has been obtained from Turkey Point Unit 4.

Q. Does Witness Jacobs identify any imprudent project management actions or decisions in 2012 that caused the EPU project cost to increase?

A. No. Witness Jacobs has not identified a single imprudent management action or decision in 2012, nor does he claim the disallowance he recommends was caused by any imprudent action or decision in 2012.

Q. Does this conclude your rebuttal testimony?

A. Yes.

MR. ANDERSON: You have asked us not to do summaries. That's fine. With that, I think we are ready for cross-examination or Commissioner questions.

CHAIRMAN BRISÉ: Sure.

MR. ANDERSON: And I did mention the rebuttal? Okay. We're good.

CHAIRMAN BRISÉ: All right. Commissioners, the floor is yours.

Okay. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And I normally use the time when a witness is conducting their summary to really focus in, so I may be a little less organized than I normally am.

CHAIRMAN BRISÉ: That's fine.

COMMISSIONER BALBIS: But, basically, I wanted to discuss with you -- there were several cost overruns in numerous categories for the EPU projects, and so I'd like to go through those, a brief discussion on those, and allow you to elaborate on them. Because I found that some of your testimony did not have the level of detail that I would like, especially when dealing with these significant overruns.

So if you start on Page 38 of your testimony, and this was brought up previously with another witness on the increase in license application costs, but there appears to be a 50 percent increase in that item.

THE WITNESS: Are you referring to the March 1 testimony or the May testimony?

COMMISSIONER BALBIS: Yes. I'm sorry, it is the March.

THE WITNESS: March 1. Commissioner, if I could, before we go line item by line item on this --

COMMISSIONER BALBIS: There is not that many lines, I assure you. But, go ahead.

THE WITNESS: If I could give you a quick summary of the total variance for 2012.

COMMISSIONER BALBIS: My entire line of questioning are on the variances, so I think that would be helpful for me.

THE WITNESS: Okay. So there are a number of TOJ exhibits in here that you can compare one year to the next for total construction cost. And then there are the AEs and the P schedules and the TOR schedules in here. And it requires an appropriate and thorough review of the details behind those to understand what is in those and what is not in those. And it's not my intent to get into those. However, the TOJ-7 exhibits don't include AFUDC, carrying costs, net book value of retirements, salvage costs. And my only point is that -- and it also does not account for changes in cash flow.

So the actual variance year over year of 2012 is $206 million. And the way you get there is you compare the TOR-2 from the May 12th filing from May 2012 to the TOR-2 filing of May 2013, and the details that roll up to that.

Now, in regards to the licensing, if you please, and I'd like to address the cost increases associated with licensing. And so in the category of licensing, that cost category includes all engineering costs associated with responding to NRC RAIs, the engineering analysis that is done by our major vendors, and as I've testified in previous hearings, there were delays in reviews, additional questions that had to be answered, and as a result it even resulted in delaying the EPU implementation for St. Lucie Unit 1, and we had to do what we call a mid-cycle shutdown to implement. So those are direct charges by the engineers that are responding to those questions by the regulatory agency.

COMMISSIONER BALBIS: Okay. And I'm going to get into more of the reasoning behind that with staff witnesses or staff auditors on your management plan. But in your position as overseeing this work, do you feel that as far as the additional work that was required by your contractors, your engineers, et cetera;

was it something that was because of their error, just additional increase in scope; was there something that FPL did to control those costs, minimize those costs; and are all of those costs warranted?

THE WITNESS: Yes. The short answer is yes. Not as a result of errors. There obviously was issues that had occurred at other nuclear plants that had license amendment requests unreviewed that called into question certain -- for one example, modeling of peak fuel clad temperature for combustion engineering supplied fuel, and that cascaded into additional questions for us that we had to answer.

Also, as you are very much aware, we had to expend an extraordinary amount of additional effort as a result of the San Onofre units and the steam generators that failed on-line because St. Lucie Unit 2 had replacement steam generators from the same supplier, but different vintage, a different design, but still those safety questions arose late in the game and had to be addressed.

As far as our overview, is we have daily -- we have detailed schedules for the vendors deliverables. We monitor their actual hours worked. They have to provide detailed reports on what their engineers are spending their time doing. We audit those. We visit their office to verify those costs are appropriate for the products that we're getting.

COMMISSIONER BALBIS: Okay. Then moving on to your TOJ-7, Page 5 of 19. And, you know, I just want to hit on a few of the high dollar variances. And that last row deals with your contractor, and it looks to be about a 70 percent variance from estimated costs to actual costs. And I know that in last year's proceeding there was some discussion about performance of your contractor in your testimony and other testimonies that you allocated that work to other contractors in order to deal with potential performance issues.

THE WITNESS: Yes. Let me clarify that. In regards to the performance, the performance of this EPC contractor is very good. What we have is that given the magnitude of the scope of growth and discovery, I guess maybe it's not the best analogy that I can think of, if you think of running the 100 meter dash, you hire Usain Bolt to run it for you. But at the point that it expands to 400 meters, even though he's a strong performer, you don't expect him to run the 400 meters by himself, and you get three people and you turn it into a relay. And that's the best analogy I can give for that.

Now, part of this variance to cost is not that the total project cost increased at all. Part of that is an accelerated payment made to our vendors. In fact, we had accelerated payments to the tune of $75 million, and so it's important to look year-over-year and not just on a line-by-line basis.

COMMISSIONER BALBIS: Okay. Then just getting back to the allocating additional work to other contractors and with your analogy on the race. In my experience that when you have a change, and to keep your race analogy, a change in horses, if you will, there are some premium costs that are associated with it. You pay the contractor, you know, the preliminary work to get up to speed on the project, et cetera. Those are just some examples that I have seen in my experience that increase the costs. Were there any premium costs or additional costs to the project because of the reallocation of the work?

THE WITNESS: No, Commissioner. In fact, it was part of our strategy, and I tried to explain that back in 2011, that one of the other major EPCs for nuclear in the United States is Shaw, and they are now known as CBI, Chicago Bridge and Iron. And they have been on the property since day one, and they do a certain amount of work for us already. Also, we employ a number of engineering firms. So Bechtel never had 100 percent of the work. And so the infrastructure of the other EPCs that we engaged and the other contractors that we engaged, such as Westinghouse, already had a presence on-site, already had some scope of work.

And what we did is as we -- it's akin to this. As the scope increases, you are now starting to really tax the best performers of a given EPC organization, and you have another EPC right there that has a number of A-team players that they can deploy and pick up the work. And what we do is we use a change management plan for the transition of that work, and we get agreement between the EPCs what can be reasonably transferred from one to the other without incurring any additional cost.

COMMISSIONER BALBIS: Okay. So then to summarize, of that variance that's listed in your TOJ-7, and I know it may be an acceleration, it may not be a true variance, but it doesn't include any premium costs that are associated with, or additional costs that are associated with the reallocation of the work.

THE WITNESS: That is correct. The reallocation of work actually winds up in cost avoidance because as evidenced by the results of the second St. Lucie outage, and the results of the second Turkey Point outage, on average they were done 20 percent faster and for lower cost.

COMMISSIONER BALBIS: Okay. Moving on to Page

14 of 19 of TOJ-7. You have another large increase for your EPC contractor of around 50 percent. In reading the variance explanation, there's discussion of the CREVs and the CREFs project, and so the same question as the previous item where was that a reallocation of work and are there any premiums? And then what caused that additional scope of work, the additional ventilation system to be added to the project, and why was that not anticipated when the project was started?

THE WITNESS: When that project was started, that was visualized as a relatively simple relocation of the air intake for the control room. And I think a picture is worth a thousand words here. If I could, and you should have -- these are all exhibits within part of TOJ-3, but if I could call your attention to -- it's going to be towards the back. Let's see here.

COMMISSIONER BALBIS: Page 44, around that area?

THE WITNESS: Right, Page 44. All that bright -- this was not what was envisioned at the beginning of the project. What was envisioned at the beginning of the project was to relocate the air intakes for the control building. The control building, the south wall is actually that white wall with the orange stripe there, and there's just two simple dampers there.

And as we got further into the regulatory and design requirements, we were required to -- even though the existing system was to the original licensing basis, we were required to apply a standard for a newer reference plan, which meant the tornado protection and hurricane protection had to be substantially more. So that super steel structure that you see there is something that is built one stick at a time, one weld at a time. And as you turn to Page 45 of 49, you can see the missile grating that gets installed.

And then on Page 46 of 49, when we talk about pipe supports, I don't want anyone to confuse, you know, when you have those braces in your closet that are holding up the shelf in a closet, you know, that's the function of a pipe hanger. In the nuclear world, that pipe that you see right there is duct work. That's Schedule 40 stainless steel pipe. So air conditioning duct work that you are used to in your home does not cut it for a control room intake, and each one of these pipes supports then, these blue structures are all individually stick built.

Now, the problem is if you turn to Page 47, we asked one of the fire watches to stand next to one to give you a sense of the scope and the scale of this, is that you can't go to Hangers R Us and buy these things.

You engineer them one at a time, you build them one at a time. And as you try and install them, again, this concrete was put in place 40 years ago and we run into steel inserts, rebar, and once you relocate one then it has a cascading effect. And so we basically took that control intake and took it from the control building all the way to the far western side of the plant, and that's not what we had originally envisioned for this project. And so that the additional cost is just associated with the sheer human capital necessary to complete that work.

COMMISSIONER BALBIS: Okay. And then the first part of my question then, there was no premium costs associated with adding that scope of work, correct? Premium costs being costs that are in addition to if it was normally anticipated in developing the scope?

THE WITNESS: No, that's correct.

COMMISSIONER BALBIS: Okay. I think I only have one more question. Bear with me. And this is the part where I would have gotten organized in your summary.

You had indicated somewhere in your testimony that there were $63 million worth of concessions. Did I --

THE WITNESS: Yes, that's correct. That was in March 1. As we did a true-up for the May 1 filing, we revised that figure, and it really worked out to be to the tune of 79 million, and that was concessions from our major suppliers. Obviously as the scope increased, that's more work for the major suppliers that are involved on the project, and so we went back to them -- because they are only paid for the actual hours they work and for products that they actually deliver.

And so the opportunity for reduction is either through efficiency or for reduced rates. So we went back to our major suppliers and negotiated reduced rates given that their volume of work had increased.

COMMISSIONER BALBIS: Okay. And those -- you know, and I guess in your testimony you didn't identify any additional costs because of this change of scope. So if you would have, I would have asked you, that is $79 million in concessions. I mean, does that cover any additional costs that were incurred?

THE WITNESS: Yes. As the scope grows and we are putting more people on the job, and they are working more hours to accomplish the total scope of the EPU, right, that TOJ-7 is -- granted, it's 19 pages, but it is still a high level summary of those additional man hours worked. That is your increased scope. And to offset that, we negotiated lower rates for the people providing that manpower to the tune of $79 million.

COMMISSIONER BALBIS: Okay. Thank you. That's all I had. Those numbers really jumped out at me, and I wanted to get further scrutiny of these costs.

CHAIRMAN BRISÉ: All right. Thank you, Commissioner Balbis.

Any further questions, Commissioners?

All right. Seeing none, I suppose there is no redirect. And is there anything else that we have to do with this witness in terms of exhibits or anything of the sort? I think we entered them earlier.

MR. ANDERSON: We just need to offer Exhibits 13 through 38.

CHAIRMAN BRISÉ: 13 through 38.

MR. ANDERSON: There is another one listed for him. We are not offering it because of the stipulation.

CHAIRMAN BRISÉ: Okay. So we will enter Exhibits 13 through 38.

Are there any objections? I'm not seeing any, so we will enter 13 through 38 into the record at this time.

(Exhibit Numbers 13 through 38 entered into the record.)

CHAIRMAN BRISÉ: Okay. With that, I think Mr. Jones can be excused. Thank you very much for your participation today.

THE WITNESS: Thank you.

CHAIRMAN BRISÉ: Okay. I believe now staff will call the next witness.

MR. LAWSON: Yes. At this time we would like to call Witnesses Fisher and Rich to the stand, please.

(Pause.)

CHAIRMAN BRISÉ: Mr. Lawson.

MR. LAWSON: Yes. Thank you, Mr. Chairman.

I'd just like to remind the Commissioners we have distributed the confidential version of their measurement report. Please remember that when we are finished we will need to return those to Theresa at the end so she can account for them. Also, we have distributed them without knowing whether or not they will be used or not at this time.

CHAIRMAN BRISÉ: Sure.

MR. LAWSON: So, if you will, we will have to take a moment to get this entered into the record at the end of it. With that, we will go ahead and begin.

LYNN FISHER and DAVID RICH

were called as witnesses on behalf of the Florida Public Service Commission Staff, and having been previously sworn to tell the truth, testified as follows:

DIRECT EXAMINATION

BY MR. LAWSON:

Q. Good evening, gentlemen. Having been sworn, would you each state your name and address for the record, please.

A. (By Witness Fisher) Yes, we have been sworn. My name is Lynn Fisher, and I work with the Public Service Commission as a Management Analyst II here at 2540 Shumard Oak Boulevard.

A. (By Witness Rich) My name is David Rich. I work in the Office of Auditing and Performance Analysis as a Public Utility Analyst IV, 2540 Shumard Oak, Tallahassee, Florida.

Q. And I believe you have jointly prefiled testimony consisting of 40 pages in this case as it relates to Florida Power and Light?

A. Yes, we did.

Q. And if I were to ask you the same questions in your prefiled testimony today, would your answers be the same?

A. Yes, they would.

A. (By Witness Fisher) Yes.

MR. LAWSON: Mr. Chairman, at this time we would ask that the Joint Prefiled Testimony of Mr. Lynn Fisher and Mr. David Rich be entered into the record as though read.

CHAIRMAN BRISÉ: All right. At this time we will enter the testimony of Mr. Fisher and Mr. Rich into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT JOINT TESTIMONY OF

LYNN FISHER AND DAVID RICH

DOCKET NO. 130009-EI

JUNE 20, 2013

Q. Mr. Fisher, please state your name and business address.

A. My name is Lynn Fisher. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed?

A. I am employed as a Government Analyst II by the Florida Public Service Commission in the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform audits and investigations of Commission-regulated utilities, focusing on the effectiveness of management and company practices, adherence to company procedures, and the adequacy of internal controls. Mr. Rich and I jointly conducted the 2013 audit of Florida Power & Light Company's (FPL) project management internal controls for the nuclear plant uprates and new construction projects at the St. Lucie and Turkey Point sites.

Q. Please describe your educational and relevant experience.

A. In 1972, I graduated from Florida State University with a Bachelor of Science degree in Marketing. My relevant background includes over twenty years with the Florida Public Service Commission in management auditing, performance analysis, process audits, and complaint investigation. Since joining the Commission, I have participated in numerous reviews of utility operations, systems, and controls, culminated in a written audit report similar to the one attached as an exhibit to this testimony. I also participated in the 2008 through 2012 reviews of FPL's project management controls for FPL's nuclear plant uprate and new construction projects and filed those audit reports in the respective dockets.

Q. Have you filed testimony in any other dockets before the Commission?

A. Yes. I filed similar testimony in Docket No. 080009-EI, 090009-EI, 100009-EI, 110009-EI, and 120009-EI. In addition to these, I previously filed testimony during 2005 in Docket No. 050045-EI. This testimony addressed an audit of distribution electric service quality for Florida Power & Light Company's Vegetation Management, Lightning Protection, and Pole Inspection processes.

Q. Mr. Rich, please state your name and business address.

A. My name is David Rich. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed?

A. I am employed as a Public Utility Analyst IV by the Florida Public Service Commission in the Office of Auditing and Performance Analysis.

Q. What are your current duties and responsibilities?

A. I perform audits and investigations of Commission-regulated utilities, focusing on the effectiveness of management and company practices, adherence to company procedures and the adequacy of internal controls. Mr. Fisher and I jointly conducted the 2013 audit of Florida Power & Light Company's project management internal controls for uprate and new construction projects at the St. Lucie and Turkey Point sites. I also participated in similar audits of FPL project management controls for uprate and new construction projects during 2009 through 2012 and filed those reports as testimony in the appropriate dockets.

Q. Please describe your educational and relevant experience.

A. In 1978, I graduated from the United States Military Academy at West Point with a

Bachelor of Science degree and a concentration in Engineering. A Masters of Arts degree in National Security Affairs from the Naval Postgraduate School followed in 1987. I am a also graduate of the United States Army Command and General Staff College and the Republic of Korea Army Command and General Staff College. My relevant work experience includes ten years with the Florida Public Service Commission in management auditing, utility performance analysis, process reviews, and trend analysis. Since joining the Commission, I have participated in numerous audits of utility operations, processes, systems, and controls which culminated in a written audit report similar to the one attached as an exhibit to this testimony.

Q. Have you filed testimony in any other dockets before the Commission?

A. Yes. I have previously filed testimony in Docket No. 090009-EI, 100009-EI, 110009-EI, and 120009-EI.

Q. Please describe the purpose of your testimony in this docket.

A. Our testimony presents the attached confidential audit report entitled *Review of Florida Power & Light Company's – Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects* (Exhibit FR-1). This audit was completed to assist with the evaluations of nuclear cost recovery filings. The report describes key project events and contract activities completed from January 2012 through May 2013 for the uprate projects at St. Lucie Units 1 & 2 and Turkey Point Units 3 & 4, and the new construction project for Turkey Point Units 6 & 7.

Q. Please summarize the areas examined by your review of controls.

A. The Office of Auditing and Performance Analysis conducted an audit of the internal controls and management oversight of the nuclear projects underway at FPL. We examined the organizations, processes, and controls being used by the company to execute the Extended Power Uprates of St. Lucie Units 1 & 2 and Turkey Point Units 3 & 4 and the construction of the new Units 6 & 7 at Turkey Point. This is the sixth annual audit of the company's controls for its nuclear uprate and construction projects. The previous reviews were filed annually, since 2008, in the Nuclear Cost Recovery Clause dockets before the Commission.

The primary objective of this audit is to assess and evaluate project key developments, along with the organization, management, internal controls, and oversight that FPL has in place or plans to employ for these projects. The internal controls examined annually are related to the following areas of project activity: planning, management and organization, cost and schedule controls, contractor selection and management, auditing, and quality assurance.

Q. Are you sponsoring any exhibits?

A. Yes, our completed audit report is attached as Exhibit Number FR-1. The audit report's observations are summarized in the Executive Summary chapter for both the Extended Power Uprate projects and the Turkey Point 6&7 new construction project.

Q. Does this conclude your testimony?

A. Yes.

BY MR. LAWSON:

Q. And I believe you have an exhibit attached to your testimony as it relates to Progress Energy Florida?

A. (By Witness Rich) No, we don't.

Q. I'm sorry, Florida Power and Light.

A. Yes, we do.

Q. Do you have any changes or corrections to that exhibit?

A. No, we don't.

A. (By Witness Fisher) No.

MR. LAWSON: Mr. Chairman, at this time I would ask that Exhibit FR-1, which is marked as Exhibit Number 68 on the Comprehensive Exhibit List, be identified as such, and entered into the record.

CHAIRMAN BRISÉ: Okay. We will enter Exhibit, I guess, what, 68 identified here as FR-1 into the record. Are there any objections? Okay. I'm not seeing any.

(Exhibit Number 68 marked for identification and entered into the record.)

MR. LAWSON: Since the witnesses are here primarily for Commissioner questions, I don't believe that the summary would be necessary, but I would just like to check with the Commissioners to see if they have any desire to hear that first.

CHAIRMAN BRISÉ: Commissioner Balbis.

COMMISSIONER BALBIS: Mr. Chairman, if it would please the majority of the Commission, I would like to hear a summary of their audit.

CHAIRMAN BRISÉ: Okay. Now, I don't think that the Commission, per se, is a party to the --

MR. LAWSON: No, the staff is not a party to this, so the giving of their summary is discretionary. It's just since we know they are here for Commissioner questions, we asked the question.

CHAIRMAN BRISÉ: Sure. And it may speed up the process, so we will go ahead and hear the summary.

WITNESS RICH: Very well.

Good evening, Mr. Chairman and Commissioners. Our testimony presents a management audit review of project management internal controls that Florida Power and Light Company uses in managing its nuclear uprates and construction of new nuclear units. The Office of Auditing and Performance Analysis has annually conducted an independent review of internal controls used by FPL for its project management methodologies.

The primary focus of our review remains the same as in previous annual reviews, to document and assess key developments for both projects. We examine company project controls in project planning, management and organization, cost and scheduling, contractor selection and oversight, internal and external auditing, and quality assurance.

Our team conducted interviews with key FPL management personnel from the uprate and new construction projects. In addition, we issued extensive document and data requests related to project management oversight, development and implementation. Items are team reviewed and evaluated, including management reports, contracts, vendor evaluations, invoices, quality assurance reports, and audits.

These documents and interview responses form the foundation of our overall assessment of the status and effectiveness of project management controls FPL employs for the uprate and new construction projects. Audit staff believes that the FPL system of internal controls, risk evaluation, management oversight, and reporting requirements adequately addressed schedule, budget, costs, performance, and risks for the extended power uprates in Turkey Point 6 and 7 projects in 2012.

From the observations on Pages 7 and 8 of our report, staff has identified two items for additional follow-up. Item Number 1, Turkey Point 6 and 7, as the project grows rapidly in the transition from licensing to construction, staff believes that FPL should reevaluate the adequacy of its project management, internal controls, and oversight protocols. And, Number 2, for extended power uprate, that unresolved warranty claims should be reviewed in the next NCRC cycle.

We welcome your questions of our efforts, Commissioners, and this concludes the summary of our testimony.

CHAIRMAN BRISÉ: Thank you very much.

Commissioners?

All right. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

And as I'm sure you recall that during last year's proceeding there were some discussions during our deliberations about management activities from Florida Power and Light, and I believe Mr. Breman during that meeting indicated that staff was going to watch this, and that the audit for next year's proceeding was going to focus on those activities to make sure that we provide the proper amount of scrutiny.

So my first question to staff is this is, I believe, the sixth annual audit, is that correct?

WITNESS RICH: Yes, Commissioner, the sixth.

COMMISSIONER BALBIS: Okay. And in light of the discussion last year, what additional scrutiny did you provide, or did you focus on anything in more detail during this audit, this year's audit? Either one of you.

WITNESS FISHER: I'm sorry, I'm not sure I understood the question. Did you say --

COMMISSIONER BALBIS: Sure. This has been an annual audit of Florida Power and Light's activities, but last year we had a discussion that audit staff was going to continue to watch FPL's management of its contractors and other activities. Did you provide any additional scrutiny or perform any additional analysis of Florida Power and Light as a result of those discussions? If so, what were they?

WITNESS FISHER: We've conducted the audit in a similar manner the entire period. We look at management reports, we look at management decisions, all the things that Mr. Rich just mentioned in the preview. So we in the past have looked at similar things. Your question, I guess, is what did we look at differently this year?

COMMISSIONER BALBIS: Yes.

WITNESS RICH: Mr. Commissioner, I would add that FPL has inserted additional layers of reporting for vendors, which we also looked at this year.

COMMISSIONER BALBIS: Okay. Specifically concerning FPL's management and project management controls for its contractor, did you provide any additional level of scrutiny, or did you feel that your audit that you performed and your review of their practices was adequate to determine if they have adequate systems in place?

WITNESS RICH: Sir, I don't believe we quantitatively added layers and layers of additional scrutiny. I believe the scrutiny that we applied is comprehensive in its nature and afforded us the ability to make sound decisions about the prudency of their management internal controls.

COMMISSIONER BALBIS: Okay. And I want to make sure that I cite the redacted portion of your report, but you indicated that what is summarized in this report is actually multiple audits, and in your report it lists, I believe, six, was it six audits. Is that correct or no? On, I believe, Page 27.

WITNESS RICH: One moment. Are you speaking, Commissioner, about 3.2.3 at the bottom of the page?

COMMISSIONER BALBIS: Correct.

WITNESS FISHER: That's FPL's internal audits.

COMMISSIONER BALBIS: Correct.

WITNESS RICH: These are not our audits.

COMMISSIONER BALBIS: And your report, though, summarizes the results of those audits, correct?

WITNESS RICH: They take them into consideration, yes, and they are included in our results.

COMMISSIONER BALBIS: Okay. And as a result of those audits, FPL found some improvements that could be made and made additional -- made some reductions to the recovery without listing the amount, is that correct?

WITNESS FISHER: Yes, they did. On Page 28, the next to the last paragraph, it gives an amount that was reversed from charges by the company.

COMMISSIONER BALBIS: Yes, and I noticed it is not highlighted, so I can say it, but it states that FPL reversed $2.4 million of charges, and they did that on their own volition as a result and review of their own internal audits, correct?

WITNESS FISHER: That is correct, yes, sir.

COMMISSIONER BALBIS: And do you feel that that reversal of charges was adequate to deal with any issues identified?

WITNESS FISHER: Yes. They actually did a series of audits to look at per diem, and the series added up to be this total of 2.14. They went back and looked at different contractors that had been paid per diem, and identified that there were some irregularities. And this was, again, their internal audit people that had conducted these audits, and then they made the changes to the amount that they filed for recovery.

COMMISSIONER BALBIS: Okay. And then I believe this is my last question, and I may have --

WITNESS RICH: Mr. Chairman, I might add to Mr. Fisher's comments that looking at it from an internal controls perspective, we found that in this case specifically that FPL's internal controls identified the problem, quantified it, and applied a solution in a comprehensive fashion.

COMMISSIONER BALBIS: Okay. And then my last question, and I probably started with this question, but I'll ask it again. You know, again, we identified something last year that staff was going to watch, and as a result of that we had this audit prepared. And so, in your opinion, do you feel that FPL's management of their contractors, they have adequate controls in place to effectively manage the project?

WITNESS RICH: Yes, sir, I think that's our conclusion. We found no evidence of imprudence in their internal controls, their policies, procedures, or practices.

COMMISSIONER BALBIS: Okay. Thank you.

And noting that at least half of these projects are completed, the uprate projects, this was our last opportunity to look at it. And I wanted to make sure this didn't slip through the cracks, because it was a point last year, and I'm glad to see that staff followed up on it.

COMMISSIONER BALBIS: Thank you, Commissioner Balbis.

Commissioners, any further questions?

All right. Staff, redirect.

MR. YOUNG: Just to follow up one question.

REDIRECT EXAMINATION

BY MR. YOUNG:

Q. Commissioner Balbis asked you what additional layers of scrutiny did you apply to this year's audit based on Mr. Breman's comments at last year's agenda dealing with the NCRC. Do you remember that line of questioning?

A. (By Witness Rich) Yes.

Q. Do you have the unredacted copy of the audit report with you?

A. Yes, we do.

Q. Can you look at Page 11?

A. I'm sorry, the page?

Q. Page 11 of the unredacted copy, and Page 31.

A. Stand by. Okay.

Q. At the top of Page 11, do you see the red -- it's not in yellow, so I can repeat it. The federal problems with the COLA, FSAR 2.5?

A. Yes.

Q. Can you explain to the Commission what additional -- what your review of that problem was? What analysis did you perform in your management audit as relates to that issue?

A. We looked at the communications both from the NRC and that flowed upwards from FPL in response to the problems that the NRC had with FSAR 2.5.

Q. And looking at Page 31, I think you touched on -- you touched on it with Commissioner Balbis, the Bechtel performance, did you look at that?

A. Yes.

Q. Can you explain to the Commission what additional review that you performed there?

A. (By Witness Fisher) Yes. I think the concern here was Bechtel's past performance and their on-going performance in 2012. Staff had some concern with Bechtel's inability to complete engineering modifications as scheduled milestones called for. Due to this potential impact on the project in terms of scheduling costs, we looked at it more closely. However, EPU project management continued to pressure Bechtel in 2012 to improve and also involved their executive level management with Bechtel's executive level management.

There were changes made to the project management team for Bechtel to improve the process, the work that was being done, and FPL continued to keep that pressure on Bechtel. So we feel that EPU management and Bechtel resolved the problems that they incurred in 2012, and FPL management continued to watch over them during the year.

MR. YOUNG: No further questions.

CHAIRMAN BRISÉ: Thank you. Any exhibits?

MR. YOUNG: We already moved the one exhibit for Mr. Rich and Mr. Fisher.

CHAIRMAN BRISÉ: Okay. Mr. Fisher and Mr. Rich, thank you for your work, and thank you for your testimony here today.

WITNESS RICH: Thank you, Mr. Chairman, Commissioners.

MR. YOUNG: Two things. One, can the witnesses be excused?

CHAIRMAN BRISÉ: Yes. We are going to excuse them at this point. So, Mr. Fisher and Mr. Rich, you are welcome to be excused. You are also welcome to stay if you would like.

WITNESS RICH: We're done.

MR. YOUNG: I don't know if Commissioner Balbis asked any confidential information, so I don't think we actually need this document to be entered into the record.

CHAIRMAN BRISÉ: No, Commissioner Balbis used the redacted version.

MR. YOUNG: Yes.

MR. LAWSON: Commissioners, at this time if everyone could return their copies of the confidential file to Theresa, she will come around to pick them up.

CHAIRMAN BRISÉ: Sure.

All right. Are there any other matters that need to be addressed?

MR. MOYLE: I just have one on this confidential information. FIPUG signed a confidentiality agreement and, you know, we are not going to do anything with it, but in terms of having the document for preparation for next year and stuff, I can work with staff, or work with the parties, or do whatever, but we'd like to have access to it as we move forward.

CHAIRMAN BRISÉ: Mary Anne.

MS. HELTON: I think that's something that Mr. Moyle and Florida Power and Light need to attempt to work out. That is certainly what our rule directs parties to do with respect to confidential information.

MR. MOYLE: We will work it out. Thanks.

CHAIRMAN BRISÉ: All right. Thank you. Okay. Are there any other matters, Mr. Lawson, that we need to have addressed at this time?

MR. LAWSON: Just one minor reminder. We have nothing else, but just a reminder. Some critical dates: Hearing transcripts will be released on the 14th of this month, August 14th; briefs will be due August 19th; the staff recommendation will be coming on September 19th; and, of course, we are scheduled for a special agenda on this matter in this docket on October 1st, 2013.

Anything else, gentlemen? And I believe that is all staff has.

CHAIRMAN BRISÉ: Okay. Thank you very much. I think we have come to the conclusion of this hearing. We thank everyone for their participation in ensuring that this was an efficient process today, and we look forward to continuing to work with you on this and many other dockets. With that, we stand adjourned.

MR. ANDERSON: Thank you, Chairman and Commissioners.

CHAIRMAN BRISÉ: Thank you.

(The hearing concluded at 5:47 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 14th day of August, 2013.

Jane Faurot

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732