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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140009-EI

NUCLEAR COST RECOVERY CLAUSE.
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VOLUME 1

Pages 1 through 282

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Monday, August 4, 2014

TIME: Commenced at 1:05 p.m.
Concluded at 1:14 p.m.

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

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

APPEARANCES:

BRYAN ANDERSON, JESSICA A. CANO, and KEN RUBIN, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408, appearing on behalf of Florida Power & Light Company.

J. MICHAEL WALLS and BLAISE N. GAMBA, ESQUIRES, Carlton Fields Law Firm, Post Office Box 3239, Tampa, Florida 33601-3239, appearing on behalf of Duke Energy Florida, Inc.

MATTHEW R. BERNIER, ESQUIRE, Duke Energy Florida, Inc., Post Office Box 14042, St. Petersburg, Florida 33733, appearing on behalf of Duke Energy Florida, Inc.

JON C. MOYLE, JR., and KAREN PUTNAL, ESQUIRES, c/o Moyle Law Firm, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, ESQUIRES, Florida Retail Federation, c/o Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of Florida Retail Federation.

APPEARANCES (continued):

CHARLES REHWINKEL, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32393-1400, appearing on behalf of the Citizens of the State of Florida

JAMES W. BREW, ESQUIRE, PCS Phosphate - White Springs, c/o Brickfield Law Firm, 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of PCS Phosphate - White Springs.

ENNIS LEON JACOBS, JR., and GEORGE CAVROS, ESQUIRES, Southern Alliance for Clean Energy, 120 E. Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334, appearing on behalf of Southern Alliance for Clean Energy.

KEINO YOUNG and CAROLINE KLANCKE, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	8	8
2 - 92	(As described on Exhibit 1)	9	
34-85			14

P R O C E E D I N G S

COMMISSIONER BRISÉ: Well, good afternoon. Today is August the 4th. It is 1:05 p.m. And so we are convening this hearing, calling it to order in Docket Number 140009-EI. Staff, please read the notice.

MR. YOUNG: Good afternoon. By notice issued July 23rd, 2014, this time and place has been set for this hearing in Docket Number 140009-EI, the Nuclear Cost Recovery Clause. The purpose of this hearing is set out in the notice.

COMMISSIONER BRISÉ: All right. Thank you. At this time we will take appearances.

MR. ANDERSON: Good afternoon. I'd like to enter the appearance of Bryan Anderson and my colleagues Jessica Cano and Ken Rubin on behalf of Florida Power & Light Company.

COMMISSIONER BRISÉ: All right. Thank you.

MR. WALLS: Good afternoon. Mike Walls with Carlton Fields Jorden Burt on behalf of Duke Energy Florida.

COMMISSIONER BRISÉ: All right. Thank you.

MS. GAMBA: Blaise Gamba also with Carlton Fields for Duke Energy Florida. And I'd also like to enter an appearance for Matthew Bernier with Duke Energy Florida.

COMMISSIONER BRISÉ: All right. Thank you.

MR. REHWINKEL: Good afternoon. Charles Rehwinkel on behalf of the Office of Public Counsel. Thank you.

COMMISSIONER BRISÉ: Thank you.

MR. BREW: Good afternoon. For White Springs Agricultural Chemical/PCS Phosphate I'm James Brew of the firm of Brickfield, Burchette, Ritts & Stone.

COMMISSIONER BRISÉ: Thank you.

MR. MOYLE: Good afternoon. Jon Moyle with the Moyle Law Firm appearing on behalf of the Florida Industrial Power Users Group, FIPUG. I'd also like to enter an appearance for Karen Putnal with our firm.

COMMISSIONER BRISÉ: Thank you.

MR. BREW: Good afternoon. I'm Ennis Leon Jacobs. I'm entering an appearance on behalf of the Southern Alliance for Clean Energy, and I'd also like to enter an appearance on behalf of George Cavros.

COMMISSIONER BRISÉ: Thank you.

MR. WRIGHT: Good afternoon, Commissioners. Robert Scheffel Wright on behalf of the Florida Retail Federation. I.'d also like to enter an appearance for John T. LaVia, III. Thank you.

COMMISSIONER BRISÉ: Thank you.

MR. YOUNG: Keino Young and Caroline Klancke on behalf of Commission staff.

COMMISSIONER BRISÉ: Thank you.

MS. HELTON: And Mary Anne Helton, advisor to the Commission.

COMMISSIONER BRISÉ: Thank you. Good afternoon, everyone. And hopefully we didn't miss anyone. I'll give you the opportunity just in case you're sitting out there and you're pining to, to intervene.

All right. Seeing none, are there any preliminary matters?

MR. YOUNG: Yes, sir. Staff, first, there are several preliminary matters, sir. First dealing with the Comprehensive Exhibit List, staff has prepared a Comprehensive Exhibit List, and the list itself is marked as Exhibit Number 1. There are no objections to the Comprehensive Exhibit List. At this time staff requests that Exhibit Number 1 be entered into the record.

COMMISSIONER BRISÉ: Okay. We will move Exhibit Number 1 into the exhibit list. Are there any objections?

Okay. Seeing none, so that is moved into the record.

(Exhibit 1 marked for identification and admitted into the record.)

MR. YOUNG: Staff requests that the Comprehensive Exhibit List and staff's stipulated exhibits be marked as numbered in the Comprehensive Exhibit List, and that any other exhibits proffered during the hearing be numbered sequentially following those listed in the staff Comprehensive Exhibit List.

COMMISSIONER BRISÉ: Okay.

(Exhibits 2 through 92 marked for identification.)

MR. YOUNG: Moving to stipulations, order of hearing. The Prehearing Officer has ruled that the companies' petition will be addressed in turn: First, DEF's petition in its entirety, then FPL's petition. However, staff would note that FPL has filed a procedural motion and, if approved, will expedite the hearing, and thus recommends that the Commission depose of FPL's motion first.

COMMISSIONER BRISÉ: Okay. How do we -- how do you suggest we proceed with that process?

MR. YOUNG: First we will deal with the FPL motion, and if it passes, then we'll take care of FPL's petition in its entirety, then proceed to Duke's petition.

COMMISSIONER BRISÉ: Okay. All right.

MR. YOUNG: Okay. On Monday, July 28th, 2014, FPL along with all the Intervenors filed a motion for approval of proposed procedural agreement and stipulation -- we termed it procedural motion -- in Docket Number 140009-EI for the purpose of streamlining the hearing process. In particular, the procedural motion, the parties agreed to waive opening statements on FPL's portion of the proceeding, cross-examination of all FPL's witnesses, and the parties, and the parties filing post-hearing briefs on FPL's portion of the hearing. If the procedural motion is approved, FPL witnesses' prefiled testimony and exhibits will be entered into the record. Staff will also request that its witnesses' prefiled testimony and exhibits be entered into the record. The procedural motion does not affect the substantive issues in the FPL portion of the NCRC docket. Thus, even if approved, the Commission will still need to address in the Category 2 substantive stipulations on FPL's -- on the issues for FPL. And any remaining disputed issues will be addressed in staff's written recommendation, which is scheduled to be filed on Monday, September 22nd, 2014.

At this time staff recommends that the Commission make the determination on FPL's procedural motion.

COMMISSIONER BRISÉ: All right. Commissioners. Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman. It is my understanding, Commissioners, that this is a procedural motion in substance, it's not contested, it streamlines the hearing process. That ultimately avoids administrative costs that would be otherwise passed on to the customers, and it will not affect the substantive issues of this proceeding. We will still be able to evaluate and consider those issues in, in September or October. October?

MR. YOUNG: Well, scheduled for the October 1st Special Agenda.

COMMISSIONER BROWN: Excellent. Thank you. That being said, I read the motion and the stipulation, and I would move approval of the motion for approval of procedural agreement and stipulation and enter that into the record.

If I may, would we be entering the testimony and the witnesses at this time as well and exhibits?

MR. YOUNG: Yes. We'll be entering the testimony and exhibits of the, for the FPL portion of the hearing. However, staff, for clarity for the record, staff will request that we go in turn for each witness's, each witness and enter its prefiled testimony and exhibits into the record, and staff and FPL will call those names.

COMMISSIONER BROWN: Okay. Then I'll stop at my motion there.

COMMISSIONER BRISÉ: All right. Is there a second?

COMMISSIONER BALBIS: Yes, Commissioner. I fully support Commissioner Brown and the motion and second it.

COMMISSIONER BRISÉ: All right. It's been moved and seconded. Any further comments?

All right. Seeing none, all in favor, say aye.

Aye.

(Vote taken.)

All right. Thank you very much.

At this time we're going to move to the other exhibits and identifying the witnesses and so forth.

MR. YOUNG: Yes, sir. As stated, as previously noted, with your approval of the procedural motion function to insert FPL's prefiled testimony and exhibits into the record. However, for clarity of the record, staff requests that FPL be afforded the ability to identify with particularity its testimony and exhibits that have been moved into the record.

COMMISSIONER BRISÉ: Okay. Ms. Cano.

MS. CANO: Good afternoon. For clarity of the record, the following has been moved into the record pursuant to the stipulation.

The testimony of Steve Scroggs, dated March 3rd, 2014, and May 1st, 2014, and Exhibits SDS-1 through SDS-11, which are marked as hearing Exhibit Numbers 34 through 44.

The testimony of Nils Diaz dated March 3rd, 2014, and Exhibit NJD-1, which is marked as Exhibit Number 45.

The testimony of Terry Jones dated March 3rd, 2014, and Exhibits TOJ-1 through TOJ-15, which are marked as hearing Exhibit Numbers 46 through 60.

The testimony of Albert Ferrer dated March 3rd, 2014, and he had no exhibits.

The testimony of John Reed dated March 3rd, 2014, and Exhibits JJR-1 through JJR-4, which were marked as Numbers 61 through 64.

The testimony of Jennifer Grant-Keene dated March 3rd, 2014, and May 1st, 2014, and Exhibits JGK-1 through JGK-11, which were marked as numbers 65 through 57.

And the testimony of Steven Sim dated May 1st, 2014, and Exhibits SRS-1 through SRS-10, which were marked as Hearing Exhibit Numbers 76 through 85. And that completes the list of the prefiled testimony and exhibits that were moved into the record pursuant to the stipulation.

COMMISSIONER BRISÉ: All right. Thank you very much. Seeing that are there are no objections, since this is an agreement, those will be moved into the record -- have been moved into the record, rather.

(Exhibits 76 through 85 admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN D. SCROGGS

DOCKET NO. 140009-EI

March 3, 2014

Q. Please state your name and business address.

A. My name is Steven D. Scroggs 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 Senior Director, Project Development. In this position I have responsibility for the development of power generation projects.

Q. Please describe your duties and responsibilities with regard to the development of new nuclear generation to meet FPL customer needs.

A. Commencing in the summer of 2006, I was assigned the responsibility for leading the investigation into the potential of adding new nuclear generation to FPL's system, and the subsequent development of new nuclear generation additions to FPL's power generation fleet. I currently lead the development of FPL's Turkey Point Nuclear Units 6 and 7 (Turkey Point 6 & 7).

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Missouri – Columbia in 1984 with a Bachelor of Science Degree in Mechanical Engineering. From 1984 until 1994, I served in the United States Navy as a Nuclear Submarine Officer. From 1994 to 1996, I was a research associate at The Pennsylvania State University, where I earned a Master of Science Degree in Mechanical Engineering. I provided consulting and management services to the regulated and unregulated power generation industry through a number of positions until 2003, when I joined FPL as Manager, Resource Assessment and Planning. I was appointed to my current position in 2006.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe FPL's activities and costs incurred in relation to the Turkey Point 6 & 7 project throughout 2013. Accordingly, this testimony contains information with respect to the project as of December 31, 2013. My testimony describes the deliberate, stepwise process FPL continues to manage so that FPL will have the opportunity to add new nuclear generation capacity for its customers. Specifically, I discuss the progress made on the project, key issues faced in 2013, and how those issues were evaluated and resolved. I also explain the Turkey Point 6 & 7 project internal controls and how those controls, supported by internal and external oversight, provide for diligent and professional project execution. Further, my testimony provides the actual expenditures incurred in 2013 and compares those expenditures to the actual/estimated values provided to the Florida Public Service Commission (FPSC) on May 1, 2013. Collectively, my testimony provides the information necessary to demonstrate that FPL's 2013 costs for the project were prudently incurred.

Q. Please describe how your testimony is organized.

A. My testimony includes the following sections:

1. High Level Project Summary and Issues
2. 2013 Project Activities and Results
3. Project Management Internal Controls
4. Procurement Processes and Controls
5. Internal/External Audits and Reviews
6. 2013 Project Costs

Q. Please summarize your testimony.

A. During 2013, FPL continued to make progress on the licensing and permitting activities required for the Turkey Point 6 & 7 project, and maintained costs within the annual budget. FPL continued its disciplined pursuit of the approvals and authorizations necessary to establish the opportunity to add the benefits of new nuclear generation for its customers. The benefits of adding new nuclear generation to FPL's system were confirmed by the 2013 annual feasibility analysis approved by FPSC Order No. PSC-13-0493-FOF-EI.

FPL achieved key milestones in the Site Certification Application (SCA) process, for example, by participating in a comprehensive SCA hearing resulting in a resoundingly affirmative Recommended Order (RO) provided by the Administrative Law Judge (ALJ). The RO recommended that the

Siting Board grant final site certification to the Turkey Point 6 & 7 project, including all associated transmission lines. In the Nuclear Regulatory Commission (NRC) licensing process, significant progress was made responding to Requests for Additional Information (RAIs) related to seismic issues and alternative sites, participating in six NRC-hosted public meetings, and updating the Combined Operating License Application (COLA) with Revision 5. FPL has maintained its disciplined and steady approach in the execution of the project, while displaying a willingness to adapt project timelines to ensure an inclusive and complete review.

The project is being managed by a professional team of engineers, analysts, and managers to ensure process controls are maintained and activities comply with applicable corporate procedures and project-specific instructions. The project management process is being conducted in a well-informed, transparent and organized manner enabling executive oversight and facilitating reviews by internal and external parties. The Turkey Point 6 & 7 project team has the skills, experience, and executive oversight to guide the project through critical decisions using the best available information. This disciplined application of good business process by well-qualified FPL managers and their staff resulted in prudent decisions with respect to project activities and expenditures.

Q. Are you sponsoring any exhibits in this proceeding?

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

- SDS-1, consisting of True-up (T) Schedules covering the 2013 actual period for the Turkey Point 6 & 7 project Site Selection and Pre-construction costs. SDS-1 contains a table of contents listing the T-Schedules sponsored and co-sponsored by FPL Witness Grant-Keene and by me, respectively.
- SDS-2, consisting of a table listing all licenses, permits and approvals FPL is preparing to support the Turkey Point 6 & 7 project.
- SDS-3, consisting of a comprehensive list of procedures and work instructions that governed the internal controls processes.
- SDS-4, consisting of a list describing various project reports, their periodicity and target audience.
- SDS-5, consisting of a comprehensive list of project instructions and forms utilized in 2013.
- SDS-6, consisting of summary tables of the 2013 expenditures.

HIGH LEVEL PROJECT SUMMARY & ISSUES

Q. What is the Turkey Point 6 & 7 project?

A. The project consists of a two-unit nuclear generating station with associated linear and non-linear facilities. The units, AP1000 design by Westinghouse, will each produce 1,100 megawatts (MW). Linear facilities include five transmission lines, a reclaimed water supply pipeline, potable water lines and a series of roadway improvements in the region. Non-linear facilities include a reclaimed water treatment facility, various buildings and facilities on the Turkey Point site and mitigation projects in the region surrounding the plant. In 2013 the project continued to focus on obtaining the licenses, permits and approvals necessary for construction and operation. A list of these licenses, permits and approvals is included in Exhibit SDS-2.

Q. What are the customer benefits that justify the continued pursuit of new nuclear generation?

A. The benefits to FPL customers offered by additional nuclear generation are numerous. The key benefits relate to FPL's core mission of providing reliable electric service at reasonable rates. The fuel required for nuclear generation is not dependent on natural gas pipelines, railroad or maritime distribution systems or subject to volatile energy markets. Therefore, nuclear generation greatly adds to the reliability of a system by increasing fuel diversity, fuel supply reliability and energy security. Nuclear fuel markets provide a stable cost input reducing the impact to monthly customer bills that result from fuel price volatility. In addition, the location of 2,200 MW of baseload generation in Miami-Dade County helps to maintain a balance of generation and load in Southeastern Florida. The feasibility analyses approved by the FPSC in 2008, 2009, 2010, 2011, 2012 and 2013 demonstrate the robust cost-effective nature of nuclear generation when compared to other baseload generation alternatives. Finally, nuclear generation is recognized as an important component of meeting state and national energy goals in addressing greenhouse gas reduction. By employing an approach that maintains progress, even during dynamic and demanding times, FPL is creating the opportunity to deliver those benefits on the most practicable schedule.

Q. Please expand on the value of FPL's approaeh to developing new nuclear generation.

A. Without the approvals, licenses, and permits needed to construct and operate a new nuclear facility, the opportunity and timeline for customers to benefit from this valuable generation source is remote and uncertain. By taking the steps to obtain the licenses and approvals, further defining the specific project, FPL is accomplishing several key objectives. First, the uncertainties around the approval process are reduced and the final definition of the project is refined. Second, the market for providing the equipment and services needed to construct the project is allowed to further mature, leveraging observations from first wave projects. Lastly, the decision to initiate construction activities will be made with very current information providing the best decision basis.

By applying this deliberate and flexible approach, FPL is able to maximize progress and the collection of information necessary to make subsequent decisions, while minimizing the current cost exposure of customers.

Q. Please summarize the progress FPL made on the Turkey Point 6 & 7 project in 2013.

A. FPL made measurable progress in all regulatory processes towards obtaining all necessary licenses, permits, and approvals. The three key processes include the Combined License (COL) process administered by the NRC, wetland permits under the jurisdiction of the US Army Corps of Engineers (USACE), and the SCA process, coordinated by the Florida Department of Environmental Protection (FDEP). In general, 2013 largely completed the information exchange with the federal agencies and provided the public hearing for the full body of evidence in the state process.

Specific areas of focus in the NRC process included seismic and geologic issues from a safety perspective, and alternative sites from an environmental perspective. Public meetings and formal RAI responses have resulted in satisfying most of the NRC's requests, with a small well-defined subset scheduled to be complete in 2014. The USACE permitting process, as designed, has maintained pace with the NRC process.

In the state SCA process, several key milestones were achieved. FDEP completed its Project Analysis Report for the plant and non-transmission portions of the project. An extensive discovery period dominated the first half of the year, while the second half was dominated by the lengthy SCA hearing. Over 90% of the hearing content focused on the location of the transmission lines associated with the project, largely due to the number of alternate corridors proposed by parties to the proceeding.

In July, the FDEP issued a permit to convert an Underground Injection Control (UIC) exploratory well to an operating well. This is an essential step in demonstrating satisfactory operation of the UIC wells proposed for the project.

Project staff continued to monitor industry milestones and events to identify potential impacts to the overall Turkey Point 6 & 7 project cost and schedule and provide indicators as to when preparation phase activities are warranted. Activities also included continued involvement in industry groups and site visits to observe key construction milestones at Southern Company's (Southern) Vogtle Electric Generating Plant (Vogtle) and SCANA Corporation's (SCANA) Summer AP1000 projects in Georgia and South Carolina, respectively.

Q. **What key events occurred in 2013 that impacted the national and international nuclear industry?**

A. As part of its efforts to incorporate lessons learned from the events at Fukushima in March 2011, the NRC issued guidelines and rules for addressing seismic reviews and beyond design basis events.

Progress continued on the Waste Confidence rule, a pre-requisite to the NRC issuing any new COLs for nuclear plants in the US. However, uncertainty around the federal budget and a government shutdown had some, albeit undeterminable, impact on the pace of reviews and resolution of outstanding RAIs with the NRC and USACE.

Q. What other national level issues were monitored for the potential impact to cost and schedule of the Turkey Point 6 & 7 project?

A. Developments in 1) the economy, 2) energy policy (at national and regional levels), and 3) the progress of international and domestic projects were monitored because they have the potential to affect the project.

The rate of economic recovery and the long term supply and pricing of natural gas has the potential to impact facets of the project, including: access to and cost of financing, material and labor costs, the development of national and international supply chains for new nuclear projects, and the overall feasibility of the project. The annual feasibility analysis addresses these issues in a disciplined and consistent manner each year. During 2013, a general improvement in the economy was observed and continued positive progress was demonstrated in supply chain development as Southern's Vogtle and SCANA's Summer new nuclear projects continued full scale construction activities in 2013.

National energy policy continues to be supportive of nuclear energy in general, and new nuclear energy development specifically, even following the Japanese tsunami and subsequent Fukushima events in March 2011. Domestic and international nuclear construction projects using the AP1000 design have continued to make progress in 2013. In China, the Sanmen and Haiyang AP1000 projects are proceeding through the construction phase, projecting operation in 2015 and 2016, respectively. Significant differences in labor and regulatory schemes limit the transferability of the full construction experience to US projects.

Q. What project-specific issues were monitored in 2013 for the potential impact to cost and schedule of the Turkey Point 6 & 7 project?

A. Project specific issues include 1) FPL system and regional economic developments influencing the annual feasibility analysis, and 2) the pace and outcome of permit and license application reviews. The impact of these factors on the project feasibility is reviewed annually.

Q. Was the feasibility of the Turkey Point 6 & 7 project re-evaluated in 2013?

A. Yes. A complete feasibility analysis was conducted to review the economics of the project using updated assumptions for system demand, fuel forecasts, environmental compliance costs, and alternative generation costs. The analysis is a two-step process, consistent with the original analysis supporting the 2008 Need Order.

The first step takes the form of developing a "break-even" cost to determine what the nuclear project could cost while remaining economically competitive with alternative baseload generation sources. That "break-even" cost is compared to the high end of the project cost estimate range. The results of the analysis confirmed that the Turkey Point 6 & 7 project is quantitatively and qualitatively superior in 5 of 7 fuel and environmental cost scenarios and shows comparable economics in the remaining two scenarios, maintaining the qualitative benefits of fuel diversity, energy security and zero emissions. These results continue to demonstrate that the new nuclear project remains the best economic alternative for FPL's customers. An updated feasibility analysis will be submitted on May 1, 2014 in the FPSC Nuclear Cost Recovery Clause (NCRC) filing.

Q. Did FPL have sufficient, meaningful, and available resources dedicated to the Turkey Point 6 & 7 project in 2013?

A. Yes. As demonstrated throughout this testimony, FPL had in place an appropriate project management structure that relied on both dedicated and matrixed employees, the necessary contractors for specialized expertise, and a robust system of project controls. These resources enabled the project to make significant progress in the current licensing phase.

2013 PROJECT ACTIVITIES AND RESULTS

Q. What were the major activities for the Turkey Point 6 & 7 project during 2013?

A. The major activities focused on completing the agency reviews of the federal and state applications, and activities supporting conversion of the UIC exploratory well at the project site.

Q. What were the specific activities and results associated with federal licensing processes for the Turkey Point 6 & 7 project in 2013?

A. FPL engaged continuously with the NRC and USACE staff throughout 2013 in an iterative process refining RAI responses to meet the specific needs of the agencies. This involved two parallel COLA review areas: the Safety analysis and the Environmental analysis. Additionally, FPL submitted its annual COLA revision.

Significant progress on the Safety analysis was made in four specific areas.

- Conducting proprietary review of 7 of 19 draft chapters of the NRC staff's Advanced Safety Analysis Report.
- Responding to 13 RAIs received in 2013 on a range of safety related topics.
- Responding to 37 RAIs received prior to 2013 on seismic and geotechnical information (Final Safety Analysis Report [FSAR] sections 2.5.1 through 2.5.3).
- Conducting the additional site data collection and analysis to answer the 21 outstanding RAIs received prior to 2013 related to seismic and geotechnical issues (FSAR sections 2.5.4).

The Environmental analysis has been focused on the alternative site analysis of FPL's Environmental Review (Section 9.3). The challenge has been to provide clarity around FPL's analysis that allows the NRC and USACE to satisfy both agencies' regulatory requirements in a single Environmental Impact Statement (EIS) narrative. FPL employed a very interactive approach to working with both agencies including weekly conference calls with agency staff, four public meetings since December 2012, and an exchange of information through NRC and USACE RAIs. Significant progress was made, clearing all RAIs that will allow publication of the draft EIS and a revised COLA review schedule for the Environmental portion.

As in past years, FPL submitted a revision (Rev. 5 in 2013) to the COLA to ensure the document incorporated the latest information from preceding COLAs and updates specific to Turkey Point 6 & 7. Following final zoning approval in Miami-Dade County of a Reclaimed Water Treatment Facility location, certain parties filed a contention in the COLA process addressing the momentary discrepancy between FPL's filed COLA and the newly zoned location. FPL addressed the issue and the proposed contention was rejected by the Atomic Safety and Licensing Board.

Q. What were the specific activities and results associated with the state SCA and permitting of the Turkey Point 6 & 7 project in 2013?

A. The year began with obtaining the final required zoning approvals from Miami-Dade County. This allowed the County to issue an affirmative Land Use Consistency determination in the SCA process. FDEP then published a Project Analysis Report (PAR) on the plant and non-transmission aspects of the project on March 3, 2013, clearing the path to the SCA hearing. The PAR recommended certification of the two unit plant and associated facilities.

April through June was occupied with a number of pre-hearing SCA activities, including significant amounts of discovery. FPL was able to negotiate 29 stipulations with state agencies, local governments and interested parties, greatly simplifying the scope of the testimony required at hearing.

The ALJ convened the SCA hearing on July 8, 2013. The hearing spanned 34 days in July, August, September and early October. During the hearing, testimony was provided by 63 expert witnesses using 910 exhibits, and included seven public testimony periods allowing another 165 members of the public an opportunity to comment. The location of the transmission lines associated with the project was the focal point of the hearings and public testimony, occupying 30 of the 34 days of hearing.

The ALJ published his 328 page RO on December 5, 2013. The RO recommended that the Siting Board should grant final certification to FPL for the Turkey Point 6 & 7 project including electrical transmission lines and other linear and non-linear associated facilities. Further, the RO recommended that the Siting Board certify the FPL East Preferred Corridor, the West Consensus Corridor and the FPL West Preferred Corridor as a backup in the event that the West Consensus Corridor cannot be secured in a timely manner and at a reasonable cost. Additionally, the RO recommended approval of all requested variances and easements included in FPL's SCA.

Q. Were there other permitting activities and results observed related to the Turkey Point 6 & 7 project in 2013?

A. Yes. In 2013, FPL continued progress on the UIC Exploratory Well and Dual Zone Monitoring Well by successfully obtaining the permit to convert the exploratory well to an operating well. The operating well permit allows FPL to proceed with the injection testing necessary to confirm the acceptability of the well operation.

Q. Please describe any activities associated with the negotiation or execution of commercial or development agreements supporting the Turkey Point 6 & 7 project in 2013.

A. FPL and Westinghouse continued discussions regarding the Forging Reservation Agreement. It was agreed to extend the expiration date of the current agreement to October 31, 2014. There were no changes to the substantive terms of the agreement.

Additionally, in support of a western transmission line corridor, FPL has been engaged in negotiations with multiple state and federal agencies to exchange its current owned transmission line corridor in the eastern Everglades for a combination of easements and property that would provide a continuous transmission right-of-way between north and south Miami-Dade County that would not be in Everglades National Park (ENP). Collectively, these efforts are referred to as the ENP land exchange. These negotiations are captured in participation agreements, authorized by federal legislation and are undergoing final environmental review by the National Park Service (NPS). Progress was made in 2013, and a draft EIS was published on January 17, 2014.

During the SCA hearing, FPL and the Miami-Dade Limestone Products Association (MDLPA) agreed to combine the northern and southern segments of the FPL West Preferred Corridor with an alternate corridor proposed by MDLPA. The combined corridor is referred to as the West Consensus Corridor, and was recommended by the ALJ for certification. The West Consensus Corridor avoids some of the area involved in the ENP land exchange, but is still dependent on the exchange occurring. The stipulation addressed environmental concerns of some parties and lessened wetland impacts. However, the integration of the West Consensus corridor added an additional level of complexity to the overall project and requires continued discussions with other parties to ensure successful execution.

Q. Please describe FPL's decision making related to the timing of initiating certain Pre-construction activities and the implications of those decisions.

A. In 2010 FPL conducted a schedule review that resulted in earliest practicable completion dates of 2022 and 2023 for Units 6 and 7, respectively. This assumed a certain pace of regulatory reviews and parallel or subsequent Pre-construction activities. Since that time, FPL has monitored the pace of regulatory reviews at the state and federal level and deferred Pre-construction activities as a means of managing project cost and risk. Included in the 2010 schedule was time margin that could accommodate some deferrals without impacting completion dates for the units. Through 2011 and 2012, deferrals indicated by the slow pace of regulatory reviews consumed a significant portion of this margin.

In 2013 two factors influenced FPL's decision making related to initiation of Pre-construction activities. As in past years, the pace of reviews was an input into decisions regarding Pre-construction activities scheduled. Particularly, the extensive SCA hearing process, continued dialogue on safety and environmental RAIs, and lack of a revised NRC COLA review schedule indicated continued uncertainty in the pace of regulatory review and warranted further deferrals of scheduled Pre-construction activities.

A second factor emerged in the form of legislative changes to the Nuclear Cost Recovery (NCR) statute. The amended statute includes additional review and approval steps prior to initiation of Pre-construction or Construction activities (See 366.93(3)(c) F.S.). Further deferral of Pre-construction activities in 2013 and the integration of new requirements of the amended NCR statute will be incorporated in the next schedule review, planned upon receipt of a revised NRC COLA review schedule.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. Please describe the project management structure that was responsible for the Turkey Point 6 & 7 project in 2013.

A. The management structure for the Turkey Point 6 & 7 project reflected the dual nature of the project relying on a working combination of two key groups: Project Development and New Nuclear Projects. The organization of the project into these two key groups helped maintain a consistent management and reporting structure with specific focus and areas of responsibility, while allowing the project the flexibility to grow and adapt over time. As the project began the final phase of regulatory reviews, it was determined to align Nuclear Project Development and the New Nuclear Project team within the Nuclear division under Chief Nuclear Officer (CNO) Mano Nazar. As of April 1, 2013, both William Maher (Senior Director, New Nuclear Licensing) and I began reporting directly to Mano Nazar. This change allowed closer alignment with the CNO organization, which maintains the regulatory relationship with the NRC and will be able to facilitate the final phase of regulatory reviews.

Project Development, which I lead, had the primary responsibility for the execution of development and licensing activities not within the purview of the NRC, project communication activities and FPSC filings. Similar to the way other generation development projects are executed within FPL, Project Development utilized matrix relationships with key business units in the company to provide essential support. For example, legal, transmission planning and environmental services were provided by those business units through assigned personnel.

The New Nuclear Project team managed the complex and specialized nature of the COLA process and the engineering, procurement and construction activities necessary to obtain licenses and permits. This team is managed by Mr. Maher. The New Nuclear Project team had direct responsibility for the production and management of the COLA. The project team will adjust staffing as the project evolves, ensuring access to the necessary skill sets are maintained to accomplish project objectives in the most cost-effective manner.

Q. Please describe the project management and staffing approach employed on the Turkey Point 6 & 7 project in 2013.

A. The project was staffed by a combination of employees fully dedicated to the project, employees from FPL business units who devoted a portion of their time to the project, and a select group of contractors and subcontractors whose subject matter expertise and skills were required to complete the considerable tasks related to this undertaking. Leading the staff was a project management team charged with monitoring the day-to-day execution and strategic direction of the project. The project management team provided routine, dedicated oversight of the project including a determination of the timing and content of external reviews. The project management team was supported by project controls professionals that executed the day-to-day project activities and provided direct oversight of procedural compliance. The project also benefited from routine review, supervision, and direction provided by FPL executive management.

Q. What were the key elements of the project management process used to manage the Turkey Point 6 & 7 project in 2013?

A. FPL routinely and methodically evaluated the risks, costs, and issues associated with the Turkey Point 6 & 7 project using a system of internal controls, routine project meetings and communication tools, management reports and reviews, internal and external audits, and the annual feasibility analysis.

Q. Please describe the system of internal controls that were applicable to the project in 2013.

A. The project internal controls were comprised of various financial systems, department procedures, work/desktop instructions and best practices providing governance and oversight of project cost and schedule processes.

Exhibit SDS-3 provides a list of procedures and work instructions that governed the internal controls processes and expectations. These procedures and work instructions were employed by dedicated and experienced project controls personnel who provided project oversight and analysis. The Project Controls organization helped to ensure appropriate management decisions were made based upon assessment of available information leading to reasonable costs. Accountability was clear and understood throughout the

Project Controls organization and was a cornerstone of the services they provide.

Q. Please describe the specific reports that were generated to monitor the project and the periodicity and audience for those reports.

A. The project relied on a series of weekly or monthly reports and had standing meetings to discuss forward-looking analysis with project managers. Exhibit SDS-4 provides a list describing the reports, and their periodicity and target audience.

Q. Please describe the staff responsible for administering these internal controls and their specific responsibilities.

A. The internal controls staffing for the project was comprised of three personnel. A Project Controls Director provided functional leadership, governance, and oversight. A Project Controls Manager provided cost and schedule direction and analysis, coordinated internal and external audit requests, held meetings with project management to review cost and schedule performance, and reviewed all cost, scope changes, schedules and performance indicators. The Project Controls Manager also participated in meetings with project management to review cost and schedule performance, provided information regarding cost, scope changes, schedules and performance indicators, maintained cost templates, supported the production of documents and responses to information requests, and met monthly or as required with department heads on forecasting and commitments. A Construction Capital

Cost Estimator maintained the master schedule and the master project estimate template.

Q. How were the internal controls developed?

A. Many of the internal controls procedures, processes or work instructions were pre-existing FPL company or department processes. However, due to the unique characteristics of the Turkey Point 6 & 7 project, cost templates were specifically developed for monitoring expenditures to support FPSC filing requirements and to facilitate associated reviews. FPL has contractually placed significant reporting requirements on contractors by requiring trend, tracking and performance indicators. This allows the internal controls team to monitor events and trends on a forward-looking basis. As the project evolves, additional controls will be developed as necessary.

Q. What are Project Instructions aud why are they needed?

A. In the course of project development, FPL identified a need to develop some business processes unique to new nuclear deployment. These processes involve conducting business in compliance with NextEra Energy, Inc. and FPL policies and procedures, but also recognize project-specific requirements. For example, specific instructions are needed to ensure compliance with additional NRC requirements for quality control and document retention. Direction for such specific areas of focus is provided to project staff through a set of FPL's New Nuclear Project - Project Instructions (NNP–PI). These Project Instructions establish a standard for the project team which provides guidance, sets expectations and drives consistency. Exhibit SDS-5 provides

FPL's comprehensive list of project instructions and forms that were utilized in 2013.

Q. What processes were used to manage project risk?

A. Cost and schedule risk was managed by ensuring the project team recognized and understood the issues facing different sub-teams that comprised the overall project. A mix of weekly meetings with small teams, monthly meetings with select members of the project team, and routine executive briefings ensured the project would benefit from sufficient and timely communication. Further, the information flow began at the working level and was integrated as it moved to the project management team to ensure the issues were adequately captured and the interaction with other portions of the project was properly assessed. These meetings resulted in several reports identified in Exhibit SDS-4. All of these routine meetings allowed project management to obtain updates from key project team members, provide direction on the conduct of the project activities and maintain tight control over project progress, expenditures, and key decisions.

Each week the project team held multiple status meetings. These meetings, held by teams within the project, tracked project activities at a level that allowed most issues to be identified, discussed, and resolved at the working team level. Examples include the COLA team, the SCA team consisting of plant and transmission sub-teams, and others. For those issues that could not be resolved at the working team level, project management provided a multistep process to elevate the issue to the appropriate level for resolution. Contractor performance was also tracked on a weekly basis. Schedule and cost metrics were monitored and reported in standard format reports to allow close monitoring of contractor performance.

The project team met monthly to review project schedule, budget performance, and key project issues. Project risk was specifically tracked and reviewed. The monthly Cost Report meeting provided an opportunity to drill down on project cost issues and expectations. Project management also provided a routine update to FPL executive management. This update provided the opportunity for dialogue between the project management team, Business Unit leaders and executive management. While the executive team was always available for consultation on developing issues and opportunities, the routine meetings ensured a broad range of topics were regularly reviewed and discussed.

The project utilized a quarterly risk assessment tool to identify, characterize and track project risks. Six areas were assessed to identify key issues, estimate probability or likelihood of occurrence (high, medium, and low), and the magnitude of potential consequences (high, medium, and low). Further, mitigation actions or strategies to be employed to manage the risk were described. A monthly project dashboard report complemented the Quarterly

Risk Analysis. This document allowed for monthly trending of project risk areas unique to the Turkey Point 6 & 7 project.

Q. What other periodic reviews were conducted to ensure the project was appropriately reviewed and analyzed?

A. Internal and external audits occur during the course of the project to ensure the project adheres to all corporate guidelines for financial accounting as well as employing best management and internal controls practices. When a deficiency is identified in an audit, an analysis is conducted to determine the cause of the deficiency and corrective actions are implemented to ensure the deficiencies are mitigated going forward. The 2013 audits are described further below.

Additionally, the project is reviewed annually to determine its continued economic feasibility. In 2013, this analysis was conducted using the same framework as the analysis accepted during the Need Determination proceeding, but was updated to reflect what was currently known regarding project cost, project schedule, and the cost and viability of alternative generation technologies. The analysis presented in the May 2013 NCRC filings demonstrate the project remains feasible. An updated feasibility study will be filed on May 1, 2014.

Q. What other activities has FPL undertaken to ensure its decision processes are informed by the most current national and international industry information?

A. FPL is an industry leader in nuclear generation, and as such, has the experience, contacts, and industry presence to engage in many forums for exploration of nuclear industry issues. Nonetheless, the specific challenges of new nuclear deployment have created focus areas requiring additional coordination between entities involved in new plant licensing, construction, and operation. FPL participated in three key industry groups providing value to the Turkey Point 6 & 7 project in 2013. The Design Centered Working Group was formed to provide coordination among owners, vendors, and the NRC related to design modifications of the AP1000. This critical activity is necessary to ensure design changes for the AP1000 are made through a consensus process with the involvement of the NRC to preserve standardization of design, a cornerstone of new nuclear development. FPL also is a member of the AP1000 owners group (APOG) (a consortium of owners of the AP1000 design) and of the Advanced Nuclear Technology group organized by the Electric Power Research Institute (EPRI). These groups are primarily forums to identify and resolve issues that are of primary interest to owners, such as staffing, training and maintenance activities. For example, programs such as Procurement Specification Development, Equipment and Nuclear Fuel Reliability improvements, Advancing Welding Practices, and Modular Equipment Testing and Benchmarking provide FPL increased efficiency in program development and implementation resulting in future cost savings. The principle of standardization through operations and maintenance requires this level of industry coordination and dialogue. These different groups have unique and important roles in the successful execution of new nuclear deployment in the US. Achieving the goal of industry standardization and realizing the associated economic and operational efficiencies requires active participation by industry participants in these venues.

Q. What steps were taken to ensure project expenditures were properly authorized?

A. For initial commitments, an approved request directed Integrated Supply Chain (ISC) to go out for bid and formally contract with the selected supplier. Initial commitments required appropriate authorizations including all documentation required by corporate procedures. This included requests for proposal, contracts, purchase orders, notice to proceed, and, if required, a single or sole source justification. For Contract Change Orders (CCOs), the requests were authorized at the appropriate level and the CCOs executed prior to releasing the supplier to perform the requested scope of work. Tracking systems and processes were used to document and record procurement activities and to obtain the appropriate level of management authorization for expenditures.

Q. How would you summarize FPL's overall approach to Turkey Point 6 & 7 project management in 2013?

A. FPL followed robust project planning, management, and execution processes to manage the Turkey Point 6 & 7 project. These efforts were led by personnel with significant experience in project management and development supported by project management professionals trained in the deliberate execution of critical infrastructure projects through a comprehensive set of internal controls. Additionally, FPL capitalized on the experience of its other power generation development projects by implementing lessons learned by those project teams. Finally, FPL implemented an ongoing internal auditing and quality assurance process to continuously monitor compliance with the controls discussed above. In summary, FPL had the right people with the right tools and oversight making decisions with the best available information. For all of these reasons, FPL is confident that its Turkey Point 6 & 7 project management decisions were well-founded and reasonable.

Further, FPL recognizes the unique nature of new nuclear deployment demands a continuous monitoring of developments in policy, regulatory and economic arenas. FPL maintains an ongoing analysis and incorporation of these events to ensure the appropriate actions are taken at the right time to establish the option for new nuclear generation. The application of sound project management fundamentals and critical questioning provides the best results.

PROCUREMENT PROCESSES AND CONTROLS

Q. What was FPL's preferred method of procurement and when might it be in the best interest of the project to use another method?

A. The preferred approach for the procurement of materials or services was to use competitive bidding. FPL benefitted from its strong market presence allowing it to leverage corporate-wide procurement activities to the specific benefit of individual project procurement activities. Maintaining a relationship with a range of service providers offered the opportunity to assess capabilities, respond to changing resource loads and remain knowledgeable of current market trends and cost of service.

However, in certain situations the use of single or sole source procurement was in the best interest of the company and its customers. In some cases there was a limited pool of qualified entities to perform specific services or provide certain goods and materials. In other cases a service provider was engaged to conduct a specific scope of work based on a competitive bid or other analysis and additional scope was identified that the vendor could efficiently provide. Circumstances such as the above examples are common in the nuclear industry, and especially on complex long-term projects such as the Turkey Point 6 & 7 project.

Q. Do you anticipate the use of single or sole source procurement practices will change over the course of the project?

A. Yes. As the project moves through various phases, the proportion of single source procurement will shift based on the nature of the major expenditures associated with each phase. During the licensing phase, the majority of the costs are expended on the federal licensing activities, which have been or will be competitively bid. In contrast, the next phase of the project will involve proprietary engineering and procurement activity that FPL must contract from the equipment provider, a sole source of these goods and services. Then, as the project moves to construction, FPL is taking steps to develop credible providers who can competitively bid specific scopes of the construction work. Developing a pool of credible vendors, especially for the very large and complex construction phase, requires a concerted effort, but is expected to result in reduced costs regardless of which vendor is selected.

Q. Please describe the single and sole source procurement procedures that applied to the Turkey Point 6 & 7 project in 2013.

A. NextEra Energy, Inc. corporate policy NEE-PRO-1470 requires proper documentation and authorization for single or sole source procurement. Such authorization must be from an individual with a commitment/spend authority at least equal to the value of the goods or services being procured. The procedure also calls for a review of the justification for reasonableness. Throughout 2013, FPL maintained its vigilance in creating adequate single or sole source documentation consistent with NEE-PRO-1470.

INTERNAL/EXTERNAL AUDITS AND REVIEWS

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

A. FPL engaged Concentric Energy Advisors (Concentric) to conduct a review of the project internal controls, with a focus on management processes, as was conducted in 2008, 2009, 2010, 2011 and 2012. FPL has addressed all recommendations provided by Concentric from prior year reviews. The 2013 Concentric review is discussed by Witness Reed.

The FPSC Staff conducts a financial audit of the project ledger and accounts and an internal controls audit annually. The 2013 audits are currently underway.

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

A. Yes. An annual FPL internal audit focuses on ensuring that costs charged to the project are for Turkey Point 6 & 7 project related activities and are recorded in accordance with NCR Rule 25-6.0423. This audit is underway to review the project costs for the period January 1, 2013 to December 31, 2013, the results of which will be available to the FPSC, its Staff, and other parties upon completion in the second quarter of 2014.

2013 PROJECT COSTS

Q. Describe the costs incurred for the Turkey Point 6 & 7 project in 2013.

A. As represented in Exhibit SDS-6 and Exhibit SDS-1, Schedule T-6, FPL incurred a total of $28,728,488 in project costs that were necessary for the activities described in this testimony. This is $549,227 less than the May 1, 2013 Actual/Estimated costs of $29,277,715.

These "Pre-construction costs" (as that term is defined by Rule 25-6.0423(2)(g)) are broken down into the following subcategories: 1) Licensing $25,637,988; 2) Permitting $1,231,174; 3) Engineering and Design $1,859,326; 4) Long Lead Procurement Advanced Payments $0; and 5) Power Block Engineering and Procurement $0.

Q. Please describe the costs incurred in the Licensing subcategory.

A. In 2013, Licensing costs were $25,637,988 as shown in Exhibit SDS-6 Table 2 and Exhibit SDS-1, Schedule T-6, Line 3. Licensing costs consist primarily of FPL employee, contractor labor, and specialty consulting services necessary to develop the COLA required for construction and operation of the Turkey Point 6 & 7 project and the state certification of the project.

Q. Please explain the reasons behind the variances between the actual Licensing costs and the costs estimated in the 2013 NCR filing in Docket No. 130009-EI.

A. Several activities resulted in higher than anticipated costs in 2013, resulting in a variance of $111,273 to the May 1, 2013 filing. In support of the NRC COLA Safety analysis, additional work scope including site investigations and engineering analysis was required to fully respond to RAIs received. Additionally, the 2013 budget assumed a certain level of activity in discovery and hearings for the SCA process. The actual duration and extent of the SCA process exceeded early estimates requiring additional expenditures for support of the extensive discovery and lengthy hearing. These higher costs were largely balanced by using a combination of contingency and re-allocation of funds not required for deferred activities.

Q. Please describe the costs incurred in the Permitting subcategory.

A. In 2013, Permitting costs were $1,231,174 as shown in Exhibit SDS-6 Table 3 and Exhibit SDS-1, Schedule T-6, Line 4. Permitting costs consist primarily of project employees and legal services necessary to support the various license and permit applications required by the Turkey Point 6 & 7 project. Exhibit SDS-6, Table 3 provides a detailed breakdown of the Permitting subcategory costs in 2013, including a description of items included within each category.

Q. Please explain any variance between the actual Permitting costs and the costs provided in the 2013 Nuclear Cost Recovery filing.

A. Permitting costs were $200,609 higher than estimated in the May 1, 2013 filing because the SCA hearing lasted longer than expected. This variance is caused by higher than anticipated hearing support costs.

Q. Please describe the costs incurred in the Engineering and Design subcategory.

A. In 2013, Engineering and Design costs were $1,859,326 as shown in Exhibit SDS-6 Table 4 and Exhibit SDS-1, Schedule T-6, Line 5. Engineering and Design costs consist primarily of FPL employee services and/or engineering consulting services necessary to support the continued permitting of the UIC exploratory well and membership fees for EPRI's Advanced Nuclear Technology working group and the APOG industry groups. Exhibit SDS-6 Table 4 provides a detailed breakdown of the Engineering and Design subcategory costs in 2013, including a description of items included within each category.

Q. Please explain any variance between the actual Engineering and Design costs and the costs provided in the 2013 Nuclear Cost Recovery filing.

A. Engineering and Design costs were $861,109 lower than planned. The variance was caused by APOG membership fees that were $400,000 lower than projected and less work associated with completion of the UIC exploratory and dual zone monitoring well.

Q. Did FPL incur any costs in the Long Lead Procurement, Power Block Engineering and Procurement, or Transmission subcategories in 2013?

A. No. In 2013, there were no Long Lead Procurement, Power Block Engineering and Procurement, or Transmission costs. Also, there was no variance in these subcategories from FPL's estimates provided in the 2013 NCR filing.

Q. Please describe the Site Selection costs incurred in 2013.

A. FPL's Site Selection work was completed in October 2007 with the filing of the Need Petition. The cost of $170,485 in this category relates to carrying charges. FPL Witness Grant-Keene supports the calculation of carrying charges.

Q. Were the 2013 project activities prudent and were the related costs prudently incurred?

A. Yes. All costs were incurred as a result of the deliberately managed process at the direction of a well-informed, properly qualified management team. The costs were incurred in the process of obtaining the necessary licenses, certifications, and permits for the Turkey Point 6 & 7 project. All costs were reviewed and approved under the direction of the Turkey Point 6 & 7 project management team and were made fully subject to project internal controls. Costs were processed using FPL standard procurement procedures and authorization processes, are reasonable and were prudently incurred.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN D. SCROGGS

DOCKET NO. 140009-EI

May 1, 2014

Q. Please state your name and business address.

A. My name is Steven D. Scroggs. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as Senior Director, Project Development. In this position I have responsibility for the development of power generation projects to meet the needs of FPL's customers.

Q. Have you previously provided testimony in this docket?

A. Yes.

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

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

- Exhibit SDS-7, Turkey Point 6 & 7 Site Selection and Pre-construction Nuclear Filing Requirement (NFR) Schedules consisting of the 2014 Actual/Estimated (AE) Schedules, the 2015 Projection (P) Schedules and the 2015 True-up to Original (TOR) Schedules. The NFR

Schedules contain a table of contents listing the schedules sponsored and co-sponsored by FPL Witness Grant-Keene and me, respectively.

- Exhibit SDS-8, consisting of summary tables presenting the 2014 Actual/Estimated and 2015 Projected Pre-construction costs for the Turkey Point 6 & 7 project.
- Exhibit SDS-9, Turkey Point 6 & 7 Project Benefits at a Glance
- Exhibit SDS-10, Turkey Point 6 & 7 Customer Savings from Nuclear Cost Recovery Law
- Exhibit SDS-11, Remaining Steps in Turkey Point 6 & 7 Licensing

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a description of how the Turkey Point 6 & 7 project is being managed and controlled. The project undertakes the steps necessary to license, construct, and operate two Westinghouse designed AP1000 nuclear reactors (AP1000) and associated transmission and ancillary facilities at the Turkey Point site near the existing Turkey Point 3 & 4 nuclear units in southern Miami-Dade County. My testimony will provide insight into how project activities are managed given the near term focus on obtaining all licenses, authorizations, and approvals and the factors influencing key decisions affecting the nature, cost, and pace of that effort. I will also describe the projected expenditures for 2014 and 2015 allowing FPL to support and defend the applications requesting the required licenses and permits and to maintain permits that have been obtained. FPL's 2014 and 2015 cost recovery requests, as in past years, include only amounts that are associated with the licensing activities currently underway. Notably, the request does not include any construction costs for the Turkey Point 6 & 7 project. No such costs are being incurred, and such costs are not permitted to be recovered at this time.

Q. Please summarize your testimony.

A. FPL continues to carefully and methodically create the opportunity for additional reliable, cost-effective and fuel diverse nuclear generation to benefit FPL's customers. The approach applied to the management of the Turkey Point 6 & 7 project provides control of cost risks while maintaining progress through the intensive licensing period. The unique qualitative benefits of fuel diversity, energy security and zero greenhouse gas emissions offered by nuclear generation are unchanged from the origin of the project. Quantitative benefits estimated for the project have decreased with improved economic factors, which on balance are beneficial for FPL's customers. Notably, progress in other nuclear industry milestones (i.e., AP1000 U.S. construction) continues to provide positive indicators for the long term feasibility of new nuclear plant deployment.

In 2014 and 2015 FPL will continue its progress on the project by concluding the state Site Certification Application (SCA) process and moving to the report review stage in the Nuclear Regulatory Commission's (NRC) Combined License Application (COLA) process. Delays in the regulatory review process have been accommodated, but will impact the licensing timeline and, ultimately, the projected commercial operation dates (CODs) of 2022 for Unit 6 and 2023 for Unit 7. An updated project schedule will be developed following receipt of a revised NRC COLA review schedule, which is the critical path for project completion. Absent a revised NRC COLA review schedule, a project schedule including revised in-service dates would be of marginal planning value.

The results of the annual feasibility analysis continue to support disciplined pursuit of the project, and reaffirm that the project can provide unique quantitative and qualitative benefits to FPL customers. FPL's stepwise approach continues to provide FPL customers with the best opportunity to make steady progress on the project. My testimony provides the Florida Public Service Commission (FPSC) with the information necessary to conclude that the licensing activities identified in this request are reasonable and in the interests of FPL customers and Floridians, in general.

Q. Would you please provide an overview of the expected benefits of the Turkey Point 6 & 7 project for FPL customers?

A. Yes. Taking into account the updated project information provided in this testimony, FPL expects the Turkey Point 6 & 7 project will:

- Provide estimated fuel cost savings for FPL's customers of approximately $644 million (nominal) in the first full year of operation based on a Medium Fuel Cost forecast;

- Provide estimated fuel cost savings for FPL's customers of approximately $64 billion (nominal) over a 40 year operating life, and approximately $173 billion (nominal) over a 60 year operating life, based on a Medium Fuel Cost forecast;
- Diversify FPL's fuel sources by decreasing reliance on natural gas by approximately 14% beginning in the first full year of two unit operation;
- Reduce annual fossil fuel usage by the equivalent of 28 million barrels of oil or 177 million MMBTU of natural gas; and
- Reduce CO_2 emissions by an estimated 267 million tons over a 40 year operating life, which is the equivalent of operating FPL's entire generating system with zero CO_2 emissions for over 6.5 years.

These quantifications are based on the May 2014 project feasibility analysis set forth in FPL Witness Sim's testimony and Exhibit SRS-1. The Turkey Point 6 & 7 project benefits are also included in my Exhibit SDS-9.

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

A. My testimony includes the following sections:

1. Policy Considerations
2. Project Approach
3. Process and Risk Management
4. Issues Potentially Affecting the Project
5. Key Decisions and Milestones
6. Project Cost and Feasibility

7. 2014 & 2015 Project Costs

POLICY CONSIDERATIONS

Q. Please provide background on Florida's Nuclear Cost Recovery statute.

A. Several key developments led to the establishment of the Nuclear Cost Recovery statute as a means of resolving persistent issues in meeting the need for stable and reasonably priced, reliable electricity for the state of Florida – in a term "fuel diversity". Primarily, the state's reliance on natural gas-fueled generation to meet the growing electricity needs of Floridians, highlighted by volatile fossil fuel prices and supply reliability issues, created concern that insufficient fuel diversity threatened the long term economic stability of the state. These concerns were reinforced in 2005 by hurricanes Katrina and Rita, which impacted natural gas production in the Gulf of Mexico, threatened FPL's fuel supply reliability, drove up natural gas prices and placed financial strain on FPL customers. Florida's significant and growing reliance on natural gas fueled generation is a result of the difficulty in being able to deploy non-gas baseload alternatives; most commonly fossil fuels (coal or oil fueled generation) or nuclear generation. For example, FPL's proposal in 2006 to build a clean coal power plant was denied by the FPSC. Nuclear Cost Recovery was initiated to directly address some of the challenges associated with deployment of nuclear generation to help improve fuel diversity and has been successful for FPL customers, as more than 520 MW of new nuclear capacity was successfully added to the system in 2013.

Q. How did Florida's reliance on natural gas develop?

A. Throughout the last several decades, significant political, economic and technology changes occurred to reshape the state's generation portfolio away from a dependence on foreign oil in the 1970s as existing plants were replaced by plants operating on other fuel sources. During this period the nuclear industry was dealing with significant regulatory, cost and schedule challenges in deploying new nuclear units – essentially keeping new nuclear capacity from being an option in the late 1980s and 1990s. The other traditional baseload alternative, coal, had only been developed in limited amounts in Florida because of the significant logistical challenges and expense in delivering large quantities of coal from supply regions located in the country's interior and concerns related to emissions. These factors opened the door for a new baseload technology. Deregulation of natural gas as a fuel for electric generation and the introduction and continued improvement of large scale combined cycle gas turbine technology evolved to provide a cost-effective, efficient and low emissions alternative. As a result, combined cycle gas turbine plants have been the technology of choice for most generation additions in the state from the 1990s to today. While customers have benefited from these choices, particularly the affordability and lower emissions of domestic natural gas, recurrence of high and volatile fossil fuel prices or supply reliability issues have impacted customers and the Florida economy in the past and, unaddressed, could impact the state again in the future.

Q. What recent developments occurred to enable new nuclear generation as a deployable alternative?

A. In the late 1990s, the NRC instituted a refined regulatory framework for the licensing of new nuclear generating units. This revised process places a high focus on the rigor and detail applied during the licensing process, avoiding or minimizing the opportunity for regulatory delays during construction or prior to operation; complications that severely impacted the prior generation of nuclear power plants. In this way, if regulatory delays occur they do so prior to significant investment reducing the financial risk in the process. Also during the 1980s and 1990s, a new generation of nuclear power plants were developed and poised for U.S. and international deployment. The federal Energy Policy Act of 2005 provided incentives and assurances that further motivated renewed interest in nuclear generation. Consortiums were formed between potential owners and manufacturers that furthered several key projects validating that the new designs and licensing processes would be successful. By 2006, a host of new nuclear projects had been proposed in the U.S. With the passage of the Florida Energy Act of 2006 and the FPSC's adoption of the Nuclear Cost Recovery rule, deployment of new nuclear capacity in Florida to address fuel diversity concerns became a realistic option.

Q. What specific considerations are included in the Nuclear Cost Recovery rule as implemented by the FPSC?

A. A core principle of the Nuclear Cost Recovery rule is that of transparency. In order to satisfy that principle, applicants for cost recovery must satisfy a number of extensive reviews. In order to enter the annual cost recovery process, an applicant must first obtain an affirmative need determination verifying that the proposed generation is required to provide cost-effective and reliable electric generation. Annually, within the cost recovery process, the applicant must provide a full accounting for all factors of the project, including cost, schedule, decisions, and ongoing feasibility. This transparency allows the FPSC to conduct in-depth oversight of the utility's actions in real time – as the project proceeds, rather than in hindsight years after decisions are made and money is spent. The FPSC then makes a "reasonableness" determination as to costs projected for the project (prior to any recovery of those costs), and reviews historical costs for "prudence". Amendments to the Nuclear Cost Recovery statute in 2013 provide for additional interim review steps as the projects proceed from licensing to preparation and subsequently, construction.

Q. How does the existence of the Nuclear Cost Recovery process assist FPL in bringing forward nuclear generation projects?

A. The statute and associated rule provides the requisite regulatory certainty necessary for FPL to undertake the complex and challenging task of adding new nuclear capacity to its system. The process allows FPL to take the long-lead steps of licensing and pre-construction and pays off interest costs during construction, reducing costs to FPL's customers. Additionally, it enables FPL to go to the financial markets and obtain competitive financing rates for the large amount of capital required to fund the construction of the project.

Q. Does the implementation of the Nuclear Cost Recovery Clause (NCRC) provide savings for FPL customers?

A. Yes. Nuclear Cost Recovery enables customers to avoid paying for compounded interest during the approximately eight year construction period and reduces the overall amount that would be recovered from customers under normal rate base treatment by billions of dollars. As shown on Exhibit SDS-10, the Nuclear Cost Recovery framework is projected to save FPL customers about $10.4 billion over the life of the Turkey Point 6 & 7 plant.

PROJECT APPROACH

Q. What is FPL's overall approach to developing Turkey Point 6 & 7?

A. FPL continues to develop Turkey Point 6 & 7 through a deliberate and careful process navigating through the four phases of project development: Exploratory, Licensing, Preparation, and Construction. The project is currently focused on the Licensing phase prior to initiating Preparation (or pre-construction) phase activities. The approach allows FPL to make progress on obtaining licenses and approvals without taking on the risks and expenditures that would result from committing to a specific construction schedule. For example, through 2015, FPL estimates it will have spent a total of $234 million on the Turkey Point 6 & 7 project – approximately 1% of the high end of the estimated project cost range ($18.4 billion).

A project of this complexity, particularly in the early stages, is subject to external factors that are not under FPL's control. Therefore, FPL's approach has been developed as a step-wise process. Routine monitoring of a wide range of factors and events is accomplished to help increase certainty and predictability, informing each subsequent step.

Q. Please expand on the concept of the step-wise process and how the risks related to the Turkey Point 6 & 7 project are controlled by key decisions.

A. The project team monitors issues at local, state, and federal levels and across technical, commercial, economic, and regulatory areas of interest. The impact on cost, schedule, and quality are routinely assessed through a set of tools and reviews. If review indicates the potential for a considerable cost or schedule impact, mitigation actions are identified and are designed to eliminate, reduce, or defer the impact. If the magnitude of the impact materially affects cost or schedule, or changes the feasibility of the project, a decision is made as to whether such impact is acceptable in light of all current information. Alternative courses of action include continuing with a modified budget and schedule along with available mitigation actions, or halting a portion of the project temporarily while the issue is further assessed or resolved. The alternative of slowing or halting a portion of the project in response to significant events or uncertainties offers a high level of risk control for FPL and its customers.

For example, the events of Fukushima in March 2011 and federal budget issues in 2010, 2012 and 2013 have constrained the resources of the NRC. FPL has chosen in past years to defer previously planned expenses associated with pre-construction activity such as engineering, procurement, and planning in response to a slower than expected pace of licensing. In this way, FPL controls the impact of schedule delays that can occur during licensing thereby lowering the project risk profile. In 2013 the Nuclear Cost Recovery statute and rule were amended to insert additional decision points, in effect establishing a step-wise progression that is highly consistent with FPL's applied project management practice.

PROCESS AND RISK MANAGEMENT

Q. How is the Turkey Point 6 & 7 project management organized to maintain an ongoing risk management focus?

A. The Turkey Point 6 & 7 project requires a wide range of skilled team members with experience in the development, design, construction and licensing of nuclear generation. The project management structure of the Turkey Point 6 & 7 project provides for dedicated teams with the requisite subject matter expertise coordinated to meet project objectives. This is accomplished through a project organization and reporting structure that effectively identifies and applies resources to issues while maintaining transparent and open communications.

As described in my March 3, 2014 testimony, the project organization relies on two principal groups jointly responsible for the integrated execution of the project. William Maher, Senior Director of New Nuclear Projects, manages the New Nuclear Plant (NNP) organization with responsibility for NRC licensing and project engineering and construction. I lead the Development organization for all other facets of project development, such as state Site Certification, local zoning approvals, public relations, and FPSC regulatory issues. Both Development and NNP report to Mano Nazar, Executive Vice President of Nuclear and Chief Nuclear Officer. Each organization is supported by FPL business units with specific, recent success in the certification, NRC re-licensing, and permitting of multiple power generation units in Florida and is complemented by our national operating experience with renewable, natural gas, and nuclear generation assets.

FPL also gives careful consideration to how it contracts for support of the many license and permit applications. A combination of competitive bidding and single/sole source procurement is used, in compliance with FPL policies, to manage augmentation of FPL staff with qualified and experienced specialty contractors and service providers.

Q. What process and risk management tools does FPL apply to manage cost, risk, and schedule objectives?

A. FPL uses industry accepted project controls, systems, and practices to obtain a high level of control over the expenditures incurred and projected for all projects. The primary means of control are 1) the project budgeting and reporting process, 2) project schedule and activity reporting processes, 3) the contract management process for external service providers, and 4) internal and external oversight processes. These processes were fully described in my March 3, 2014 testimony and continue to be utilized in the oversight of the project.

Q. Please provide examples of specific tools used to manage the project.

A. The PTN 6&7 Licensing Project Dashboard presents issues and the current trends for those issues. Over time, if a problematic issue continues to trend down or remains neutral, the effectiveness of the project management controls are investigated to determine if changes in approach can create improvement, or if mitigation measures are adequate.

Project Memoranda, describing the background and analysis considered in project decisions, are an example of a tool developed to ensure a higher level of documentation and transparency in the management of the project. These memoranda document decisions made with respect to project features, policies, contracts, cost estimates, and schedules.

Additionally, a quarterly risk summary tracks the assessment of project risks over time. This summary qualitatively gauges the probability of occurrence and impacts to implementation, cost, and schedule aspects of the project.

Q. What activities are undertaken by the project to address industry issues affecting the long term success and execution of the project?

A. FPL is involved in a number of areas to address issues relevant to new nuclear deployment. FPL participates in three specific groups comprised of new nuclear industry owners and design vendor(s). These include the Design Centered Working Group (DCWG), the AP1000 Owners Group (APOG), and the Advanced Nuclear Technology group. The collective purpose of these groups is to identify and resolve issues potentially affecting the licensing, design, construction, operation, and maintenance of the AP1000 design. Individually, each group provides a collaborative forum for owners to work with each other, the design vendor and the NRC to achieve standardized solutions to the issues facing all owners. This enables the industry to maintain a high level of standardization from the earliest stages of new nuclear deployment. Standardization of designs and processes provides benefits to FPL customers in terms of efficiency and cost control.

ISSUES POTENTIALLY AFFECTING THE PROJECT

Q. What are the international, national, and regional issues being monitored for their effect on the Turkey Point 6 & 7 project?

A. FPL monitors issues that can affect the overall timeline or feasibility of the project. Several of these factors, directly or indirectly, influence the scope and pace of regulatory reviews. For example, the NRC's response to the March 2011 Japanese earthquake and tsunami has indirectly resulted in added scope to the safety review of FPL's Turkey Point 6 & 7 COLA and impacted the resources available to conduct that review. Other factors relate to updated information that must be incorporated into FPL's decision making process and feasibility analysis. This information includes the lessons being gathered at the two U.S. AP1000 construction sites, as well as the most current economic forecasts for input into the project planning and analyses processes.

Q. What factors in the federal license and permit review processes may affect the overall timeline of the project?

A. The federal processes include the safety and environmental reviews that inform the NRC COLA process, as well as additional reviews conducted by the Army Corps of Engineers (USACE) in support of the Section 404(b) wetland permit applications. Looking forward, several factors are being monitored for potential impact.

As a result of the government shutdown in late 2013, the NRC's subcontracts supporting the environmental review were terminated. With funding restored, these subcontracts were subsequently reinstated, but some delay occurred as the issue was addressed. Additionally, the pace of the environmental review has been impacted by resources being diverted to the Waste Confidence

Environmental Impact Statement (EIS), a priority for the NRC. The USACE relies on the Turkey Point 6 & 7 EIS produced through the NRC COLA process for its Section 404(b) permitting review. Delay in the NRC EIS process directly impacts the USACE process.

Similarly, the NRC staff is now completing reviews of additional analyses related to seismic, geologic and geotechnical engineering. The pace of the safety review has been impacted by resources being diverted to the hydrology and seismology issues resulting from the events at Fukushima in 2011. A schedule for completion of the COLA review, expected later in 2014, will establish a higher level of schedule certainty for completion of the licensing phase and will support development of a revised Turkey Point 6 & 7 project schedule.

The Atomic Safety and Licensing Board (ASLB) has reviewed contentions to the Turkey Point 6 & 7 COLA over the past years. All contentions offered by opponents have been dismissed with the exception of one related to certain constituents within waste water from the plant. FPL has conducted additional analyses and will seek to have that contention dismissed. If successful, the Turkey Point 6 & 7 COLA would not require a contested hearing, reducing the time required to obtain a COL.

There are also several NRC proceedings that relate indirectly to the Turkey Point 6 & 7 project. These include the rulemaking related to the long term storage of high-level radiological waste, commonly referred to as "Waste Confidence". The NRC has indicated that it will not issue a new COL until that rulemaking is complete. Additionally, there is an ongoing rulemaking related to Spent Fuel Pools. A motion has been made to suspend activity on the Turkey Point 6 & 7 COLA (and other applications) until the Spent Fuel Pool rulemaking has been completed. Neither rulemaking appears to present a negative impact to the expected receipt of the Turkey Point 6 & 7 COL, the schedule of which I discuss in greater detail later in this testimony.

Q. Has NRC staff recently provided an estimate of milestone dates in the Turkey Point Unit 6 & 7 COLA review schedule?

A. Yes. In response to a specific request by the ASLB, NRC staff provided estimates of certain key milestones in an April 10, 2014 letter. In an April 17, 2014 letter to FPL, NRC staff confirmed the environmental dates provided in the April 10, 2014 letter. While these letters do not provide a revised COLA review schedule, they provide information that is helpful in estimating the remaining steps in the licensing phase. The potential implications of these letters are discussed in the next section of this testimony.

Q. What factors at the state and local levels may affect the pace of the state Site Certification process?

A. Due to the interests of parties to the state Site Certification, the duration of steps within the process have taken longer than originally anticipated. While this additional time ensures that all parties' concerns are appropriately addressed, it challenges the ability to develop a precise schedule. Beyond the Siting Board decision anticipated in mid-2014, it is possible that the Certification may be appealed by those opposed to specific aspects of the project, namely a single 230 kV transmission line in Eastern Miami-Dade County. The appeal would be heard by a District Court of Appeal and could require 12 to 18 months to complete.

Q. Does FPL monitor the progress of international new nuclear energy projects?

A. Yes. However, FPL focuses on U.S. projects given the difference in regulatory, economic, political and supply chain factors between U.S. and international projects.

Q. What do recent developments related to the progress of new nuclear energy projects in the U.S. indicate with respect to the continued pursuit of the Turkey Point 6 & 7 project?

A. The new nuclear construction projects at Southern Company's (Southern) Vogtle Electric Generating Plant (Vogtle) in Georgia and SCANA Corporation's (SCANA) Summer AP1000 projects in South Carolina continue to make progress. Specifically, in 2013 both projects moved from site preparation and non-nuclear construction into the safety related construction authorized by the Combined License under NRC jurisdiction. In 2014, the projects completed foundation work and began moving major equipment and pre-fabricated modules into position.

Both the Vogtle and Summer projects are largely complete with the engineering design and procurement steps and are complete with more than one third of construction. Therefore, the predictability of costs and schedule for the projects are much higher than projects in earlier stages. The advanced status of these projects provides benchmarks for comparison of FPL's cost estimates and post-licensing schedule.

In general, the status of these projects continues to demonstrate that substantial and consistent progress is being made on deploying the next generation of nuclear projects. Further, it indicates that the construction phases of these complex projects can be managed within predictable budget and schedule parameters.

Q. What is the status of a Department of Energy (DOE) Loan Guarantee for the Vogtle or Summer projects?

A. In February 2014, Georgia Power closed on a $3.46 billion loan guarantee for the company's 45.7% interest in the Vogtle 3 & 4 project. Oglethorpe Power, owner of a 30% stake in the Vogtle project, also closed on a $3.06 billion loan guarantee. Municipal Electric Authority of Georgia is pursuing finalization of a $1.8 billion loan guarantee for its minority interest in the Vogtle project. Terms of the guarantees have not been disclosed, however Georgia Power has projected approximately $225 million savings, on a present value basis, to its customers based on reduced interest fees provided by the loan guarantee.

SCANA continues to discuss loan guarantees for the Summer project, but has yet to commit to obtaining the guarantees.

Q. What would be required to obtain a DOE Loan Guarantee for the Turkey Point 6 & 7 project?

A. Essentially, a new solicitation issued by the DOE Loan Guarantee Office would be required. The solicitation would define the eligibility requirements and terms of application which would guide FPL's actions. Upon submission of an application, the Turkey Point 6 & 7 project would be evaluated for eligibility and specific discussions defining the terms and conditions of a loan guarantee would be initiated. FPL is prepared to pursue such a guarantee should one be offered, and should FPL determine that participation would benefit its customers.

Q. What do recent developments related to the national and regional economy indicate with respect to the continued pursuit of the Turkey Point 6 & 7 project?

A. The economic downturn affected forward demand and fuel price forecasts, but it also reduced the rate of price escalation and the projected costs of materials and labor. The pace of recovery is expected to be steady for the near term. Additionally, the significant shift in supply relative to demand in the natural gas industry has created a near term reduction in natural gas prices and has reduced long range forecasts for price levels. FPL Witness Sim addresses the effect of changes in FPL demand forecasts and natural gas price forecasts on the economic feasibility of Turkey Point 6 & 7.

Q. What do recent developments related to national and regional energy policy indicate with respect to the continued pursuit of the Turkey Point 6 & 7 project?

A. National energy policy remains supportive of nuclear energy in general, and new nuclear energy development in specific. Challenges to existing nuclear generators in certain markets has become a focus of the administration as these generators greatly assist in attaining emission reduction goals set by the federal government. Further, the recent closing of the loan guarantees for Vogtle underscores the desire of the federal government to promote generation technologies that reduce or eliminate greenhouse gas emissions, maintaining progress towards meeting policy goals. In general, while cautious, policymakers continue to recognize the long term benefits of and need for existing and new nuclear generation capacity.

Regionally, the legislature amended the Nuclear Cost Recovery statute in 2013. Notably, the amendments resulted in maintaining cost recovery as originally envisioned, with added opportunities for the FPSC to review the project prior to initiating major milestones. Reliability, cost-effectiveness, fuel diversity, fuel supply reliability, and price stability are still benefits to be delivered by increasing nuclear generation capacity and are still needed by FPL's customers. A future plan that does not include new nuclear capacity increases and prolongs reliance on fossil fuels, increases exposure to fuel supply reliability and price volatility, and is not as effective at reducing system emissions, including greenhouse gas emissions, when compared to a plan that does include new nuclear generation capacity.

KEY DECISIONS AND MILESTONES

Q. What will be the focus of the project in 2014 and 2015?

A. The focus will remain on completing the state Site Certification process and obtaining the federal licenses and permits necessary to construct and operate the Turkey Point 6 & 7 project. The milestones required to obtain these goals are discussed below and summarized in Exhibit SDS-11. Following state certification, the project will conduct necessary post-certification activities required to comply with conditions of the state certification and other approvals obtained to date.

Q. What specific milestones are expected in relation to completing the NRC licensing process?

A. Based on the correspondence with the ASLB on April 10, 2014, and correspondence to FPL on April 17, 2014, NRC staff estimates publication of the Draft EIS by February 2015 followed by the Final EIS in February 2016. Further, the staff estimates that the Final Safety Evaluation Report (SER) will be published in March 2017. It is anticipated that the NRC staff will develop a revised COLA review schedule later in 2014. Using these estimated dates and the experience of earlier COLA review schedules, FPL estimates that the ASLB would hold a contested hearing in the later part of 2016 and, with completion of the Final SER in March 2017, the NRC would be able to make a decision on the Turkey Point Unit 6 & 7 COL in September 2017.

Q. Are there assumptions included in these estimates that may change, and therefore affect the schedule?

A. Yes. As stated in the April 17, 2014 letter, the estimates for the environmental dates are based on the NRC's current assessment of the availability of resources for the Turkey Point Unit 6 & 7 COLA review. The NRC is addressing competing priorities and reassigning resources to resolve the Waste Confidence issue, limiting the available resources required to complete the environmental review. Similarly, FPL understands that additional seismic reviews and actions related to the NRC's response to Fukushima for existing nuclear plants have placed demands on resources necessary to complete the safety review. The availability of NRC resources to complete the Turkey Point Unit 6 & 7 COLA review will be impacted by the progress made in these two important areas, and other potential developments.

At a project level, there are two specific assumptions that may offer an opportunity to better the current milestone estimates. The SER timeline assumes two additional rounds of Requests for Additional Information of six months each, where only one round may be necessary. Additionally, the overall timeline assumes the need for the ASLB (contested) hearing. As discussed previously, if the last contention is dismissed, the contested hearing would not be required and the overall schedule may gain six months.

Q. Did FPL anticipate that the NRC regulatory process could be extended?

A. Yes. The potential for this schedule change was foreseen and this type of change is at the core of how FPL has chosen to proceed on this important project. As I indicated last year before this Commission, "Things that are not under FPL's control are federal budget issues, sequestration, and other items that affect the NRC's resource and their resource allocation." (See Transcript Docket 130009-EI, page 609, lines 12-15). The NRC gives priority to emerging issues that affect the existing nuclear fleet. FPL is making every prudent effort to deliver the benefits of the project on the earliest practicable schedule, while being mindful of the potential for and impact of delays. In fact, this has been FPL's position throughout this project.

Q. What specific milestones are expected related to the USACE Section 404(b) process?

A. As described in prior sections, the USACE will utilize the NRC EIS as its Record of Decision for the Section 404(b) permits. Thus, the timing of these permit activities closely follow the NRC process up to the point of the Final EIS. When the Draft EIS is published for comment, the USACE will publish a notice of the permit application. In parallel to the National Environmental Policy Act based EIS process, the USACE will similarly complete a review under the Clean Water Act to determine the Least Environmentally Damaging Practicable Alternative. This will include a wildlife consultation with the U.S.

Fish & Wildlife Service. It is expected that the Section 404(b) permits could be issued within four to six months following completion of the Final EIS in 2016.

Q. What specific milestones are expected related to the state Site Certification process in 2014 and 2015?

A. The Siting Board is expected to vote on the Certification on May 13, 2014. If approved, the Certification would be issued by May 20, 2014, and a 30 day appeal period would begin. Any appeals would be heard in a District Court of Appeal and could require 12 to 18 months to resolve. FPL will take necessary actions required by Conditions of Certification (CoC) to maintain compliance.

Q. What type of activities are required by the CoC, and what is the timing associated with these activities?

A. The CoC identify specific activities (such as monitoring plans or reports, management plans and wildlife surveys) necessary to demonstrate compliance with the CoC and applicable regulatory requirements. The time requirements for these activities vary based on the activity in question. Some are required within a specified period of time following an event, such as Certification or completion of construction. Some precede an event, such as commencement of construction or commencement of operation. Only those activities necessary to maintain compliance with the terms and conditions of the Certification will be undertaken without specific authorization of the FPSC, in accordance with Section 366.93, Florida Statutes.

Q. Please provide an example of results associated with the state Site Certification process that may affect the project cost or schedule.

A. FPL entered into stipulations and CoC were imposed that require FPL to undertake certain activities. For example, a monitoring program associated with the Radial Collector Well (RCW) system was included as a CoC that will require significant groundwater and ecological monitoring before, during and after construction of the RCW system. This is an example of the type of activity that could not be specifically estimated prior to the Certification, but is now more defined, allowing for a better assessment in the project cost and schedule estimating process.

Q. What specific milestones are expected for the Everglades National Park Land Exchange process in 2014 and 2015?

A. The Draft EIS was published in January and comments were accepted from the public through March 18, 2014. The U.S. National Park Service will address the comments received and is expected to produce a Final EIS in fall 2014. Any agreement resulting in the land exchange would occur following the Final EIS, and will likely include terms and conditions as established by the Secretary of Interior. Negotiation of those terms and conditions will be the critical path to reaching a final exchange agreement.

Q. Is there any pre-construction work anticipated in 2014 and 2015?

A. No. Based on current information, FPL anticipates that the licensing activities will extend beyond 2015. Therefore, only activities that are related to obtaining or maintaining the necessary licenses, permits or approvals are planned to be undertaken in 2014 and 2015.

FPL's step-wise management allows the project to continue progress to a later stage where risks can be better quantified and more specifically mitigated. Considering all project specific and industry factors, this is a responsible and prudent course of action to continue progress in creating the opportunity for new nuclear generation for our customers.

Q. Are there other project decisions that have occurred or are expected in 2014 or 2015?

A. Yes. FPL executed a Forging Reservation Agreement with Westinghouse in 2008 to secure manufacturing capacity for ultra-heavy forgings to support the project's original schedule. The agreement has been extended several times to allow FPL and Westinghouse to monitor industry developments and determine the best disposition of the existing agreement. The current extension expires October 31, 2016.

PROJECT COST AND FEASIBILITY

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

A. The overnight capital cost estimate range is $3,750/kW to $5,453/kW. When time-related costs such as inflation and carrying costs are included, and CODs of 2022 and 2023 are assumed, the total project cost ranges from $12.6 to $18.4 billion.

Q. Please explain how the overnight cost estimate is constructed and how it is used to help evaluate the feasibility of the project each year.

A. An overnight cost is developed using the most current information available. An overnight cost provides an estimate of the total project costs assuming all costs occur at one point in time ("overnight") and time-related costs (escalation, interest during construction) are not included. Further, recognizing many things could influence the overnight cost, additional analysis is conducted on each component of the overnight cost to explore how much it could vary, resulting in a cost estimate range. The overnight cost provides an indication of the cost per kilowatt ($/kW) for the project in a given year reference. The 2013 cost estimate range was $3,659/kW to $5,320/kW in 2013 dollars. Updating the cost estimate range provides a cost estimate range of $3,750/kW to $5,453/kW in 2014 dollars. The cost estimate range has been adjusted to current year dollars by assuming a 2.5% escalation over the years between 2007 and present. While the actual escalation experienced has been generally lower, retaining this simple assumption is conservative and consistent with past year evaluations.

A breakeven cost analysis is developed by FPL's Resource Assessment and Planning Department, and is further discussed by FPL Witness Sim. This breakeven cost is provided as an overnight cost and is directly compared to the cost estimate range to assess the economic feasibility of the project.

Q. Have there been any revisions to project features or design or any industry-wide developments in the past year that suggest a revision to the overnight capital cost estimate range?

A. No. A review was conducted to capture any potential changes and estimate the potential cost impact. No significant changes or developments have occurred in the past year that indicate any revisions are necessary to the project cost estimate range. In general, the Recommended Order resulting from the SCA preserved the project and ancillary features as proposed by FPL, and is therefore consistent with the project as envisioned in the current cost estimate range.

Q. Does FPL's cost estimate range continue to be reasonable?

A. Yes. The FPL cost estimate range continues to be reasonable based on the annual review of the Turkey Point 6 & 7 capital cost estimate, a comparison to other U.S. AP1000 project overnight capital cost estimates and progress reports, and Concentric Energy Advisors' review of U.S. AP1000 project overnight and total estimated costs.

This is reassuring when one recognizes that the costs being experienced by the lead projects at Vogtle and Summer are informed by committed contracts, are well into the construction cycle, and include significant equipment and material purchases. Therefore, the total project costs estimated for the projects in construction are more certain.

Q. **What future activities are anticipated that will provide information to revise the overnight capital cost estimate range?**

A. Negotiations on the Engineering, Procurement and Construction contract will provide more information including price, terms and schedules to support an execution plan for project construction. That information will be integrated with continued observations of the progress of preceding U.S. projects to inform and revise the Turkey Point 6 & 7 non-binding cost estimate, as warranted.

Q. **What factors may impact the overall project cost estimate, including time-related costs such as price escalation and carrying costs?**

A. The primary factors affecting the total project cost will be the actual labor and materials costs experienced during the Preparation and Construction periods. The certainty around these costs will increase as preceding projects move through the early stages of construction and as FPL negotiates the principal contracts for engineering, procurement, and construction of the project. The pace of expenditures is also a critical factor that will impact total project costs. Escalation of future costs and carrying costs on expended funds are time related factors.

Q. **What is the estimate of the total project costs based on the current project schedule?**

A. As described above, there are a number of assumptions made to arrive at this estimate. Under the existing 2022/2023 in-service date schedule, and using the 2014 overnight cost estimate range, the total project cost range becomes $12.6 billion to $18.4 billion for the 2,200 MW project.

Q. Would the project cost range be significantly higher if the in-service dates were assumed to be later in time?

A. Not necessarily. Although later in-service dates would allow escalation more time to affect the total project cost, the actual impacts of such a decision would be determined by the primary market factors: material and labor costs at the time of purchase.

Q. What are the most current Turkey Point 6 & 7 economic feasibility analysis results?

A. As discussed by FPL Witness Sim, the most current feasibility analysis affirms the projected cost effectiveness and benefits associated with the Turkey Point 6 & 7 project using the same basic analytical approach applied in the Need Determination proceeding for the project and the six prior NCRC filings. The analysis calculated a projected "break-even" cost for new nuclear; a cost that results in the same life cycle costs (or cumulative present value of revenue requirements) as an alternative plan relying on natural gas combined cycle units assuming a 40 year operating life. The analysis was conducted for seven scenarios comprised of combinations of three fuel and three emission cost forecasts. The projected break-even costs were higher than FPL's non-binding cost estimate range for its Turkey Point 6 & 7 project in two of seven scenarios, within the cost estimate range for four scenarios and lower than the cost estimate range in one scenario. These results indicate that the Turkey Point 6 & 7 project is quantitatively superior to the combined cycle gas alternative plan in two scenarios and four scenarios fall within the cost estimate range. The combined cycle alternative was economically superior in a scenario which assumes continued low costs for both natural gas and environmental compliance for 50 years. However, a nuclear facility is the only meaningful opportunity to deliver the qualitative benefits of fuel diversity, energy security and zero greenhouse gas emissions.

Q. Is a 40 year operating life assumption conservative?

A. Yes. The term of forty years was chosen as a conservative estimate of the operating life of the units based on the initial term of the NRC Combined License. Historically, the initial license terms have been renewed for an additional 20 years for many of the existing reactors in the U.S. today. FPL's Turkey Point Units 3 and 4 and St. Lucie 1 and 2 units have successfully extended the original license terms by 20 years. Therefore, it is reasonable to assume that a 20 year extension would be attainable for the Turkey Point Unit 6 & 7 project.

Q. How would the breakeven analysis results change if it is assumed that the operating life of Turkey Point Units 6 and 7 is actually 60 years?

A. The results indicate that the Turkey Point 6 & 7 project is quantitatively superior to the combined cycle gas alternative plan in five scenarios, while two scenarios fall within the cost estimate range.

Q. **In February 2010, FPSC Staff provided a list of factors for consideration in the feasibility analysis. Have those factors been considered?**

A. Yes. FPL Witness Sim discusses the economic factors and I discuss the non-economic factors.

Q. **What non-economic factors affect the project's long term feasibility?**

A. Non-economic factors include the feasibility of obtaining all necessary approvals (permits, licenses, etc.), the ability to obtain financing for the project at a reasonable cost, and supportive state and federal energy policy.

Significant progress continues on the federal, state, and local approvals required for the construction and operation of the project. During 2013, the state certification process was largely completed and should be complete in 2014. Similarly, the federal licensing efforts are moving forward in 2014 and are estimated to be complete by 2017 as discussed previously. While the review process has taken longer than originally anticipated, the process is proceeding substantively as expected.

Financing will be determined as the project proceeds through approvals to construction. The lead projects, Vogtle and Summer, have successfully obtained financing, and Vogtle has closed on a significant federal loan guarantee. FPL will continue its dialogue with the financial community to help maintain FPL's capability to obtain financing with reasonable terms.

As discussed earlier in this testimony, state and federal energy policy continues to be generally supportive of new nuclear generation for a host of reasons. Recent legislative activity in Florida sought to revise some aspects of the Nuclear Cost Recovery statute, but preserve the opportunity it provides. The high reliability, low and stable cost, and zero greenhouse gas emission profile of nuclear generation technology remains highly compatible with key energy policy objectives.

Q. Does FPL intend to pursue completion of the Turkey Point 6 & 7 project?

A. Yes. The critical path to completing Turkey Point 6 & 7 requires obtaining the licenses and approvals necessary to construct and operate Turkey Point 6 & 7. Once the project is closer to obtaining the approvals, FPL will be able to refine the economic assumptions and incorporate the experience of other new nuclear projects as well as how state and federal energy policies have evolved. The FPSC will continue to have the opportunity to review FPL's plans through the NCRC process.

Q. Does FPL have sufficient, meaningful, and available resources dedicated to the Turkey Point 6 & 7 project?

A. Yes. As demonstrated throughout this testimony, FPL has in place an appropriate project management structure that relies on both dedicated and matrixed employees, the necessary contractors for specialized expertise, and a robust system of project controls. These resources enable the project to progress through the current licensing phase.

2014 & 2015 PROJECT COSTS

Q. How are the 2014 Actual/Estimated costs and the 2015 Projected costs developed?

A. FPL has a disciplined ground-up process to develop project budgets. This process was used in the initial project budgeting activity and is routinely reviewed and evaluated for adequacy and accuracy as additional information becomes available. The estimates of the 2014 Actual/Estimated and 2015 Projected costs were completed in accordance with FPL's budget and accounting guidelines and policies. Where services are contracted, rates are provided by the contractor and reviewed to verify the charged rates are consistent with FPL's experience in the broader industry. The cost estimates were compared to other costs being incurred by the Company for similar activities and found to be reasonable.

Q. Please provide a high level summary of the 2014 Actual/Estimated and the 2015 Projected costs presented in this filing.

A. The costs associated with the Turkey Point 6 & 7 project in 2014 and 2015 are focused on supporting the licensing and permit application reviews underway. Additional costs are incurred in the Engineering & Design category associated with completing the Underground Injection Control (UIC) Exploratory Well, a necessary step towards approval of that process.

Q. What changes may occur that could affect these cost projections?

A. The pace and content of the application reviews may impact the actual costs in 2014 and 2015, however this is anticipated to be significantly less than experienced in the past as the processes are coming to a close.

Q. Please summarize the costs included in this filing for Turkey Point 6 & 7 Pre-construction activities.

A. Schedule AE-6 of SDS-7 presents the 2014 Actual/Estimated costs in the following categories: 1) Licensing $16,582,678; 2) Permitting $588,412; 3) Engineering and Design $3,069,539; 4) Long Lead Procurement advance payments $0; 5) Power Block Engineering and Procurement $0; and 6) Transmission $0. Schedule P-6 of SDS-7 presents the 2015 Projected costs in the following categories: 1) Licensing $11,027,251; 2) Permitting $245,684; 3) Engineering and Design $1,907,788; 4) Long Lead Procurement $0; 5) Power Block Engineering and Procurement $0; and 6) Transmission $0. Table 1 of Exhibit SDS-8 provides a summary of the Actual/Estimated 2014 and Projected 2015 Pre-construction costs. The descriptions in the Exhibit SDS-8 tables are illustrative and do not provide full line item detail.

Q. Please describe the activities included in the Licensing category for the 2014 Actual/Estimated costs and the 2015 Projected costs.

A. For the period ending December 31, 2014, Licensing costs are estimated to be $16,582,678 as shown on Line 3 of Schedule AE-6 of SDS-7. For the period ending December 31, 2015, Licensing costs are projected to be $11,027,251 as shown on Line 3 of Schedule P-6 of SDS-7. Table 2 of Exhibit SDS-8 provides a detailed breakdown of the Licensing subcategory costs.

Licensing costs consist primarily of FPL employee and contractor labor and specialty consulting services necessary to support the various license and permit applications required by the Turkey Point 6 & 7 project. The license and permit applications contain project specific information, assessments and studies requested by various regulatory authorities to support the reviews leading to decisions on the technical, environmental and social acceptability of the project. Other licensing activities include costs associated with the SCA, USACE permits and delegated programs such as Prevention of Significant Deterioration and UIC. In 2014 and 2015 these costs will increasingly be related to the NRC COLA and USACE 404(b) permit processes, as the state Site Certification is concluding. A portion of the 2014 and 2015 expenditures will be used to pursue lesser approvals, and maintain compliance with those approvals received. Licensing and Permitting costs are developed in accordance with budget and accounting guidelines and policies. Some activities are common between applications, and therefore offer opportunities to coordinate efforts and manage costs. Further, these cost estimates were compared to FPL's extensive experience with the development and permitting of new generation projects in Florida and found to be reasonable.

Q. What are the major differences between the 2014 Actual/Estimated values and those projected in the May 1, 2013 filing for the Licensing category?

A. The Actual/Estimated values for the Licensing category in 2014 are higher than the amount projected for 2014 in 2013. Primarily, the increase is based on the extension of the SCA process into 2014, the extension of the Everglades National Park Land Exchange process into 2014 and the additional technical responses required by the NRC in the seismic, geological and geotechnical engineering areas.

Q. Please describe the activities in the Permitting category for the 2014 Actual/Estimated costs and the 2015 Projected costs.

A. For the period ending December 31, 2014, Permitting costs are estimated to be $588,412 as shown on Line 4 of Schedule AE-6 of SDS-7. For the period ending December 31, 2015, Permitting costs are projected to be $245,684 as shown on Line 4 of Schedule P-6 of SDS-7. Table 3 of Exhibit SDS-8 provides a detailed breakdown of the Permitting subcategory costs, including a description of items included within each category. Permitting costs include costs for the Development team, in-house legal support, and resources to conduct necessary outreach educating stakeholders about the project.

Q. What are the major differences between the 2014 Actual/Estimated values and those projected in the May 1, 2013 filing for the Permitting category?

A. The difference is driven by a reduction in labor costs in this category and a reduction in contingency in this category, based on anticipated completion of the state Site Certification process.

Q. Please describe the activities in the Engineering and Design category for the 2014 Actual/Estimated costs and the 2015 Projected costs.

A. The Engineering and Design activities performed in 2014 and 2015 are primarily related to supporting the permitting effort for the UIC well system. For the period ending December 31, 2014, Engineering and Design costs are estimated to be $3,069,539 as shown on Line 5 of Schedule AE-6 of SDS-7. For the period ending December 31, 2015, Engineering and Design costs associated with preliminary engineering activities are projected to be $1,907,788 as shown on Line 5 of Schedule P-6 of SDS-7. Table 4 of Exhibit SDS-8 provides a detailed breakdown of the Engineering and Design subcategory costs, including a description of items included within each category.

Costs for participation in industry groups include the Electric Power Research Institute Advanced Nuclear Technology working group (with annual fees of $275,000) and the DCWG (no external charge to participate in this group). The fee for participation in APOG is expected to be approximately $2 million in 2014 and $1 million in 2015. These costs are necessary to obtain the benefits of membership described earlier in this testimony.

Q. What are the major differences between the 2014 Actual/Estimated values and those projected in the May 1, 2013 filing for the Engineering and Design category?

A. The major difference is a carryover of costs that were not incurred in 2013 on the UIC exploratory well. Costs associated with completing the UIC injection test were incurred in early 2014, with minimal costs remaining in the year.

Q. Please describe the activities in the Long Lead Procurement category for the 2014 Actual/Estimated costs and the 2015 Projected costs.

A. For the period ending December 31, 2014 and December 31, 2015, Long Lead Procurement costs are projected to be $0 as shown on Line 6 of Schedule AE-6 of SDS-7 and line 6 of Schedule P-6 of SDS-7. Future Long Lead Procurement costs are anticipated to be included in the Power Block Engineering and Procurement cost category.

Q. Please describe the activities in the Power Block Engineering and Procurement category for the 2014 Actual/Estimated costs and the 2015 Projected costs.

A. For the period ending December 31, 2014, Power Block Engineering and Procurement costs are estimated to be $0 as shown on Line 7 of Schedule AE-6 of SDS-7. For the period ending December 31, 2015, Power Block Engineering and Procurement costs are projected to be $0 as shown on Line 7 of Schedule P-6 of SDS-7.

Q. Please describe the activities in the Transmission category for the 2014 Actual/Estimated costs and the 2015 Projected costs.

A. For the period ending December 31, 2014, Transmission expenditures are estimated to be $0 as shown on Line 25 of Schedule AE-6 of SDS-7. For the period ending December 31, 2015, Transmission expenditures are projected to be $0 as shown on Line 25 of Schedule P-6 of SDS-7.

All 2014 and 2015 costs associated with Transmission planning are related to the licensing and permitting activities, and therefore are appropriately included in those categories, described above.

Q. **Are FPL's Actual/Estimated 2014 and Projected 2015 Turkey Point 6 & 7 costs reasonable?**

A. Yes. FPL's 2014 and 2015 expenditures are reasonable and necessary to obtain the licenses and permits which will allow FPL to carefully and methodically create the opportunity for additional reliable, cost-effective and fuel diverse nuclear generation to benefit FPL customers. FPL uses a robust system of project controls, systems, and practices to obtain a high level of control over the expenditures incurred and projected. Together, these support a finding that FPL's Actual/Estimated 2014 and Projected 2015 expenditures are reasonable.

Q. **Does this conclude your direct testimony?**

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF NILS J. DIAZ

DOCKET NO. 140009-EI

March 3, 2014

Q. Please state your name and business address.

A. My name is Nils J. Diaz. My business address is 2508 Sunset Way, St. Petersburg Beach, Florida, 33706.

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

A. I am the Managing Director of The ND2 Group (ND2). ND2 is a consulting group with a strong focus on nuclear energy matters. ND2 presently provides advice for clients in the areas of nuclear power deployment and licensing, high level radioactive waste issues, and advanced security systems development.

Q. Please describe your other industry experience and affiliations.

A. I presently hold policy advising and lead consulting positions in government and industry, board memberships in private institutions. I recently chaired the American Society of Mechanical Engineers Presidential Task Force on Response to Japan Nuclear Power Plant Events. I previously served as the Chairman of the United States Nuclear Regulatory Commission (NRC) from 2003 to 2006, after serving as a Commissioner of the NRC from 1996 to 2003. Prior to my appointment to the NRC, I was the Director of the Innovative Nuclear Space Power and Propulsion Institute for the Ballistic Missile Defense Organization of the U.S. Department of Defense, and Professor of Nuclear Engineering Sciences at the University of Florida. I have also consulted on nuclear energy and energy policy development for private industries in the United States and abroad, as well as the U.S. Government and other governments. I have testified as an expert witness to the U.S. Senate and House of Representatives on multiple occasions over the last 30 years. I also served as a Commissioner on Florida's Energy and Climate Commission from 2008 to 2010. Additional details on my background and experience are provided in my resume, which is attached as Exhibit NJD-1.

Q. Are you sponsoring any Exhibits in this case?

A. Yes. I am sponsoring Exhibit NJD-1 - Summary Resume of Nils J. Diaz, PhD.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the prudence of Florida Power & Light Company's (FPL's) continued pursuit of a Combined Operating License (COL) for the Turkey Point Nuclear Units 6 and 7 (Turkey Point 6 & 7) project in 2013 in light of certain nuclear industry and regulatory considerations.

Q. How have you prepared for your review of FPL's approach to the licensing of Turkey Point 6 & 7?

A. I have been well-informed of FPL's Combined Operating License Application (COLA) for the Turkey Point 6 & 7 project since participating in the Need Determination proceedings for Turkey Point 6 & 7 and subsequent Nuclear Power Plant Cost Recovery proceedings. I am knowledgeable regarding the Westinghouse AP 1000 new nuclear plant design referenced by FPL in its COLA, having worked on the certification of that design when I was on the NRC, and afterwards. I have also reviewed FPL's project approach, as described in detail in the Direct Testimony of Steven Scroggs, FPL's Senior Director for Project Development for the Turkey Point 6 & 7 project, filed with the Commission prior to 2014 and on this date. I have also discussed FPL's approach and certain licensing-related issues with Mr. Scroggs and other key project personnel. Finally, I am familiar with past and ongoing NRC reviews of other COL applications.

Q. **Was FPL's approach to the continued pursuit of a COL for the Turkey Point 6 & 7 project in 2013 prudent?**

A. Yes. Based on my review, the decisions and management approaches used by FPL during 2013 were prudent and consistent with a reasonable strategy for pursuing the licensing of the proposed Turkey Point 6 & 7 project.

Q. **Is it feasible for FPL to receive a COL to pursue construction and operation of Turkey Point 6 & 7?**

A. Yes. In fact, I am confident that FPL will receive a COL license upon satisfaction of NRC requirements for public health and safety, the environment and the common defense and security.

Q. **Please comment on the NRC regulatory reviews and requirements addressing the Fukushima events, as they relate to the feasibility of licensing Turkey Point 6 & 7 and the prudence of FPL's approach.**

A. The NRC has continued to evaluate and act on the lessons learned from the March 2011 nuclear events in Japan. The implementation of the most important recommendations (Tier 1 and Tier 2) of the NRC's Near Term Task Force

(NTTF) on Fukushima has advanced satisfactorily, and key beyond-design-basis issues have been addressed. These include seismic, flooding, station blackout and fuel pool instrumentation.

Presently, the recommended NTTF actions with the highest priorities have been enacted into requirements by orders and rulemakings, and information gathered from licensees regarding site-specific issues. For example, in May 2013, the NRC staff issued the final Implementation of Regulatory Guide 1.221 on Design-Basis Hurricane, which is applicable to the COL for Turkey Point 6 & 7. Moreover, on December 6, 2013, the Staff issued its recommendations to the Commission for the disposition of Recommendation 1 of the NTTF in December 2013. This encompassing recommendation proposed establishing a "logical, systematic, and coherent regulatory framework for adequate protection that appropriately balances defense-in-depth and risk considerations." This previously open-ended regulatory issue, with potential significant impact on licensees, has now been presented for Commission resolution with a coherent set of improvement activities to categorize design-basis events and requirements in a forward-looking manner, to establish Commission expectations for defense-in-depth via a policy statement, and to clarify the role of voluntary initiatives in NRC regulatory process. The Turkey Point 6 & 7 team is mindful of these issues for future action, if necessary.

As I have testified in the past, I do not anticipate that the events at Fukushima will have a significant impact on the ability to obtain a license for, or to ultimately construct and operate, Turkey Point 6 & 7. With respect to new reactors, the NRC has recognized the significant safety enhancements already inherent in reactors with passive safety systems, such as the AP 1000 reactor selected for the Turkey Point 6 & 7 project. The NRC has stated that "all of the current COL and design certification applicants are addressing new seismic and flooding requirements adequately in the context of updated NRC guidance." The NRC staff also concluded that "[b]y nature of their passive design and inherent 72-hour coping capability for core, containment and spent fuel cooling with no operator action required, the . . . AP 1000 design [has] many of the design features and attributes necessary to address the Task Force recommendations." It is apparent that the certified AP 1000 reactor referenced in the Turkey Point 6 & 7 COLA is likely to satisfy the majority of the post-Fukushima changes under consideration by the NRC. Those regulatory changes affecting the FPL COL are mostly established and should be well-incorporated into the final safety review prior to issuance of the license.

With respect to Turkey Point 6 & 7 specifically, the NRC continued during 2013 to use its Request for Additional Information (RAI) process to gather requisite information about the proposed project, including seismic, geophysical and environmental issues. FPL proactively engaged NRC staff with frequent communications and participation in public meetings to ensure Staff had the information they needed to continue making progress in its review.

In my opinion, it was prudent for FPL during 2013 to continue to pursue a COL referencing the AP 1000 Design Certification and to engage NRC staff in the manner described above.

Q. **Please comment on the status of the NRC's waste confidence rule as it relates to the feasibility of licensing Turkey Point 6 & 7.**

A. The NRC is scheduled to complete the Generic Environmental Report and Rulemaking for the remanded Waste Confidence Rule by about October 2014. Expert opinions indicate that the published preliminary report should be in compliance with the Court requirements. In a related important matter, connected also to the Fukushima issues in 2013, the Staff "concluded that the continued operation of nuclear power plants with high-density loadings in their SFPs [spent fuel pools] does not challenge the NRC's safety goals or related QHOs [quantitative health objectives]." This specific conclusion regarding spent fuel storage is also applicable to the Turkey Point COLA. The NRC will take final action on pending applications when the NRC issues its revised rulemaking. The progress on the Waste Confidence Rule in 2013 supports the feasibility of FPL's Turkey Point 6 & 7 COL issuance.

Q. **Are there other NRC regulatory issues that FPL is monitoring?**

A. Yes. The issue of the finality of standard design certifications, like the AP1000 Design Certification referenced in FPL's COLA, and its relationship to changes during construction is being monitored by FPL.

FPL applied for a COL that references the Design Certification of the AP1000, as established by Appendix D to 10 CFR Part 52. The advantage of this approach is that the issues resolved during the design certification rulemaking are precluded from reconsideration at the combined license stage.

Because standardization remains a key objective of the NRC regulatory framework, significant efforts have been made to minimize changes to design certifications, often referred to as the "design finality considerations" established by 10 CFR Part 52.63. The finality considerations protect the licensee from potential design changes that are not necessary to assure adequate protection of the public health and safety. At the same time, finality considerations impose certain restrictions on changes that an applicant for a COL and a licensee might want to make to the certified design.

Design changes that are generic in nature, such as those impacting the industry following the NRC's post-Fukushima orders and rulemaking, are handled by Westinghouse through the Design Center Working Group. Such changes result in revisions to the certified safety design. However, there are also differences between the certified safety design and the detailed design used for plant construction at a particular site. As a result, 10 CFR Part 52 provides a process by which applicants may seek design changes as part of the licensing process on a site-specific basis. Applicants must therefore consider performing detailed design for the construction of a certified design, prior to and after the issuance of a COL, to help avoid delays during plant construction. All of the support engineering and analysis work that may be necessary to clarify the detailed design for construction and its conformance with the design certification, or the evaluation of the need for changes or license amendments, is not only necessary from a licensing perspective, but also contributes to the decision-making necessary for construction.

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. 140009-EI

March 3, 2014

Q. Please state your name.

A. My name is Terry O. Jones.

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

A. In 2013, I was employed by Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprate. I am now retired from FPL.

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

A. I was appointed Vice President, Nuclear Power Uprate on August 1, 2009. I was responsible for the management and execution of the Extended Power Uprate ("EPU" or "Uprate") Project through its completion in 2013. I provided executive leadership, governance, and oversight to ensure the safe and reliable implementation of the EPU Project for the four FPL nuclear units. In that role, I reported directly to the Chief Nuclear Officer.

Q. Please describe your educational background and professional experience.

A. 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. My testimony presents and explains the EPU Project and key management decisions, project activities, and costs incurred in 2013. I also describe the procedures, processes, and controls that ensured FPL's EPU Project expenditures were reasonable and the result of prudent decision making, and the careful engineering based processes employed by FPL to ensure that it included in its Nuclear Cost Recovery (NCR) request only nuclear Uprate Project costs that were "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. What is the current status of the EPU Project?

A. The EPU Project is complete. The project met its goal of providing about 400 megawatts (MWe) of fuel diverse generation for FPL's customers by 2012, and exceeded that goal by providing a total of 522 MWe in 2013. Exhibit TOJ-2 shows a high-level EPU Project timeline.

Q. Has the EPU Project been evaluated by others in the energy industry?

A. Yes. The EPU Project has been recognized by the Nuclear Energy Institute (NEI), Power Engineering magazine, and Platts Global Energy.

On March 21, 2013, the NEI notified NextEra Energy, Inc. that the Nuclear Fleet EPU Project Team received 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.

Additionally, the FPL EPU Project received the 2013 Project of the Year - Best Nuclear Project award from Power Engineering magazine. In determining which project should receive this award, Power Engineering magazine considers how the project was technologically groundbreaking or innovative, how the project impacted the community in which it resides, and what the logistical hurdles were that project developers had to overcome when constructing the project. According to the award announcement, "FPL has demonstrated that these massive plant upgrades are not only major feats of engineering and construction but also economically practical."

Finally, the FPL EPU Project was named a finalist in the Platts Global Energy Award in the construction category, Premier Project Award for Construction. The judging criteria considered project challenges, financial results, innovation, operational excellence, safety, and project scope.

Exhibit TOJ-3 summarizes the NEI, Power Engineering magazine, and Platts awards.

Q. Please summarize your testimony.

A. FPL successfully completed the EPU Project that was approved in 2008 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 I can report that it has exceeded that goal. In fact, with the completion of the Turkey Point Unit 4 EPU outage in April of 2013, the project has added a total of 522 MWe for the benefit of FPL's customers, which is nearly 31% more than what was anticipated during the 2007 need filing. The uprate work completed at Turkey Point Unit 4 during 2013 is producing 21% more power than FPL initially projected the unit would deliver. This 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.

The EPU Project was an enormous effort requiring the employment of thousands of workers. During the final EPU outage in 2013 – the last of nine – there was an average of over 1,600 workers daily assigned to the EPU outage activities for the 108 outage days. The EPU workforce over the life of the project is shown on Exhibit TOJ-4. Because FPL was able to incorporate lessons learned from prior outages, the Turkey Point Unit 4 EPU outage was completed 15% faster and at a 19% lower cost than the Unit 3 outage. In addition to the successful completion of implementation work at Turkey Point, FPL completed thousands of project closeout activities at St. Lucie and Turkey Point, including completion of final adjustments to components and systems, finalization of engineering documents, and site restoration, to name a few. In total, the EPU Project required about 2.5 million man hours of work during 2013. FPL prudently incurred approximately $250 million of EPU construction costs during 2013, which is about $10 million less than the estimate of $260 million presented in my May 2013 testimony.

Q. How are customers benefiting from the EPU Project?

A. When the project was completed in 2013, the total increase of electrical output as a result of the EPU Project was 522 MWe for FPL's customers. Among other benefits, this increase in nuclear power output: (i) enhances system reliability and integrity by diversifying FPL's fuel mix; (ii) provides energy and baseload capacity to FPL's customers without greenhouse gas emissions; (iii) provides significant fuel cost and environmental compliance cost savings; and (iv) provides increased capacity to help maintain balance between generation and load in Southeastern Florida. Specifically, 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 $3.2 billion over the life of the plants;
- Increases FPL's nuclear generating capacity by about 18%;
- Reduces FPL's reliance on natural gas by about 3% beginning in the first full year of operation, providing an important hedge against volatile natural gas prices;
- Adds to Florida's energy security because the uprated units do not depend on fuel delivery through Florida's only two natural gas transmission pipelines;
- Provides a total amount of energy that is equivalent to the usage of approximately 332,000 residential customer households each year;
- Reduces annual fossil fuel usage by the equivalent of almost 7 million barrels of oil or 44 million mmBTU of natural gas annually;
- Reduces CO2 emissions generated in making electricity to serve FPL's customers by 34 million tons over the life of the plants; and

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

These benefits are also presented in Exhibit TOJ-5.

Q. Now that the EPU Project is complete, has FPL quantified the customer benefits resulting from the NCR process?

A. Yes. FPL's EPU investment in Florida's energy infrastructure and economy has been made possible by the legislature's policy to support investment in nuclear projects, set forth in the NCR statute, and the Commission's careful implementation of that policy through the NCR rule. The project would not have been performed without that clear Florida policy direction and support. Florida's NCR process permits recovery of carrying costs, not construction costs, through the clause. Exhibit TOJ-6 (page 1) shows FPL's recovery amount compared to its investment.

Now that the EPU Project is complete, and final costs are known, FPL has calculated the cost savings for customers due to the NCR process. Because carrying charges have been collected during project construction, FPL's customers will save more than $300 million dollars (nominal) compared to rates under the Allowance for Funds Used During Construction approach that otherwise would apply. These customer savings are presented in Exhibit TOJ-6 (page 2).

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

A. My testimony includes the following sections:

1. Project Summary
2. 2013 Project Activities
3. Project Management Internal Controls

4. Procurement Processes and Controls
5. Internal/External Audits and Reviews
6. "Separate and Apart" Considerations
7. 2013 Construction Costs

PROJECT SUMMARY

Q. Please describe the EPU Project.

A. The EPU Project increased FPL's nuclear generating capacity from its four existing nuclear units by fitting the units with higher capacity and more efficient turbines, generators, heat exchangers, transformers, and other necessary equipment to accommodate increased steam flow that results from increased reactor power. This involved 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 the EPU work at Turkey Point Unit 4 in 2013 are attached as Exhibit TOJ-7, which also includes pictures of completed EPU systems operating in the uprated conditions. Each replacement/modification was considered a project in and of itself which was integrated into the EPU implementation work scope. For some major modifications, permanent plant equipment had to be removed in order to have the necessary access to perform modifications and was then reinstalled as part of the construction process.

Because the project modified FPL's operating nuclear plants, it was a much different and more challenging 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. All of the work was successfully completed on existing nuclear plants while at all times maintaining strict nuclear operations safety. FPL performed almost all of the modifications during the units' planned refueling outages. Performing the uprate work during the planned refueling outages minimized the amount of time that these low fuel-cost generators were off line.

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

A. The EPU Project contributes to grid stability by producing power where it is consumed. Growth in electrical load in the Southeast area within FPL's service territory means that FPL must either add new generation to that area or rely on transmission lines to import the needed energy. Adding locally-sited generation contributes to grid stability and is more reliable than 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 if storms take out transmission lines. Additionally, the increased generation close to the load reduces system transmission line losses, meaning, more power is available for customers to use. The EPU Project's impact on the Southeast area is presented in Exhibit TOJ-8.

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

A. FPL 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. About 365 MWe additional output from the EPU Project 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 EPU outage, the total EPU electrical output for FPL's customers was 522 MWe. (The total output for all Florida residents was 545 MWe.) Exhibit TOJ-9, EPU Project Electrical Output Status, demonstrates the timing of the additional output that has been realized.

Q. Did FPL include industry best practices into the work that was performed for the EPU Project?

A. Yes. For example, the FPL project team members participated in nuclear industry working groups organized by the Institute of Nuclear Power Operations and the Nuclear Energy Institute and benefited from lessons learned at other plants. This was supplemented with direct engagement with our industry peers through benchmarking trips to other nuclear sites to incorporate best practices. These sources helped ensure project decisions were supported by the best information currently available. The project benefited from the experience of previous unit outages where other project work was performed and lessons learned for future Uprate Project modification implementation activities. Additionally, other utility professionals visited FPL's sites to learn from FPL's best practices.

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

A. Nuclear and industrial safety was central to everything FPL did on the EPU Project. Nuclear safety was successfully ensured at every step. FPL, its employees and its contractors did not take for granted FPL's safety record on the EPU Project. The project's 2013 Federal Occupational Safety and Health

Administration, Recordable Incident Rate was 0.16 which is significantly less than the industry-wide injury rates of 3.7 for Construction and 2.8 for utilities as reported by the US Bureau of Labor Statics, US Department of Labor, November 2013. Excellent project safety is one of the factors considered by utility and construction industry professionals to be a hallmark of strong project management.

2013 PROJECT ACTIVITIES

Q. What key activities occurred in 2013 in execution of the EPU Project?

A. Key activities that occurred in 2013 included:

- Continuous intensive management of vendors, suppliers, and contractors;
- Completion of Engineering Design Modifications;
- The successful completion of the ninth and final EPU outage in April of 2013, adding approximately 126 MWe; and
- The successful completion of demobilization, site restoration, project closeout, and turnover activities at the St. Lucie and Turkey Point plants.

Q. Please describe the engineering design modification activities in 2013.

A. The engineering design modification process was the process by which the detailed modification packages were prepared. Calculations were performed, construction drawings were issued, general installation instructions were provided, and high level testing requirements were identified. In 2013, design engineering modification activities were primarily to support implementation of the already approved modifications during the final EPU outage. Approximately 140,000 engineering man hours were expended during the 2013 portion of the Turkey Point Unit 4 EPU outage.

Q. Please discuss the EPU implementation work that was successfully completed in 2013.

A. The final EPU outage was successfully completed in April 2013, with an increased capacity of approximately 126 MWe of additional nuclear power for FPL's customers. The Turkey Point Unit 4 implementation work in 2013, including the engineering design work described above, required the following:

- An augmented staff of approximately 3,000 additional people at its peak in January;
- Thousands of individually planned, scheduled, and monitored activities supporting approximately 3,300 work packages; and
- About 2 million man hours of work.

It also involved 1,435 large bore pipe welds, 2,040 small bore pipe welds, 4,651 feet of electric wiring conduit, 38,443 feet of electrical cable, and 4,712 electrical terminations. An illustration of the component replacements and modifications for Turkey Point Unit 4 is attached as Exhibit TOJ-10. Exhibit TOJ-11, EPU Project Work Activities List, includes a listing of the EPU implementation work activities at Turkey Point.

Q. Were EPU systems placed into service in 2013?

A. Yes. Exhibit TOJ-12 lists the EPU Project systems and components that were placed into service and included in the 2013 base rate filing.

Q. Did FPL experience engineering design scope growth and construction complexities associated with the EPU work on Tnrkey Point Unit 4 in 2013?

A. Yes. Some challenges were experienced in the planning and execution of the many major modifications; however, not nearly to the extent experienced on the other units in 2012. FPL utilized the experience gained at St. Lucie and 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. As a result, the Turkey Point Unit 4 EPU implementation outage was completed in less time and at a lower cost than the Turkey Point Unit 3 EPU implementation outage. The Turkey Point Unit 4 outage was completed 15% faster and at a 19% lower cost than the Turkey Point Unit 3 EPU outage.

Q. Did FPL perform EPU Project close out activities in 2013?

A. Yes. FPL performed thousands of EPU closeout activities in 2013. The activities included the following:

- Completion of final adjustments to components and systems, including adjustments to process instrumentation loops to optimize performance and enhancements to the spent fuel pool handling machines;
- Completion and testing of control room simulator modifications;
- Finalization of engineering documents to as built conditions, update of plant drawings, and work order closeout for engineering changes;
- Final Safety Analysis and design basis documentation updates;
- Evaluation of preventive maintenance requirements for new and modified components and development of preventive maintenance work orders;
- Post-EPU Project restoration of the plant areas used by EPU personnel to pre-EPU conditions which included storage areas, workshops, and labor assembly areas, and removal of temporary cranes, lighting, and machinery used to support the EPU Project;
- Project staffing reductions to meet project closeout needs;
- Demobilization of vendors in accordance with project closeout plans;

- Verification and validation of spare parts;
- Closeout of contracts;
- Completion of procedure and simulator updates; and
- Systematic turnover to each unit's staff.

The 2013 EPU Project closeout activities at St. Lucie and Turkey Point are included in Exhibit TOJ-11.

Q. Please describe FPL's efforts to manage vendor costs in 2013.

A. FPL diligently managed its vendors to ensure the costs expended for the assigned scopes of work were reasonable and appropriate. FPL continued to require 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 with major contractors during outages 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.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. How was the project planning, execution, contractor oversight, and closeout described above managed by FPL in 2013?

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-13, EPU Project Instructions (EPPI) Index as of December 31, 2013, is provided to illustrate the types of instructions that were used.

Q. Please describe the EPU Project Management organization during 2013.

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 completed the implementation phase and/or closeout activities 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 project close activities were completed.

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

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

A. 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 were only for those FPL personnel authorized to charge time to the EPU Project;
- Conducting on-going analysis to evaluate project costs to ensure they were "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 were appropriately allocated to the correct Internal Order established for each nuclear unit's outages;
- Assisting in the classification of Property Retirement Units;
- Set up and maintenance of 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 were capital and which were O&M;
- Managing internal and external financial audit requests and ensuring that any findings and recommendations were dispositioned, as appropriate; and
- Providing oversight and guidance to the EPU Project team in maintaining accounting-related project instructions current to ensure compliance with corporate policies and procedures, and Sarbanes-Oxley processes.

Q. What other schedule and cost monitoring controls were in place during 2013?

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 analyses and associated performance indicators on a routine and forward-looking basis thus allowing Project Management to make informed decisions. Exhibit TOJ-14, EPU Project Reports 2013, lists many of the reports that were a direct result of the information the Controls group provided, analyzed and produced. The number and types of reports changed appropriately as the project progressed through the closeout activities to completion.

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.

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 analyses based on all available cost and schedule information at its disposal.

Q. What periodic reviews were conducted in 2013 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 nuclear and industrial safety, quality, schedule, and costs. These included the following:

- Daily meetings to mutually share lessons learned 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;
- Periodic 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;
- When appropriate, FPL Executive Steering Committee presentations on the status of the project; and

- Routine Project Meetings involving FPL and individual major vendors to discuss project schedules and challenges.

As mentioned above, the EPU Project continued to produce several reports in 2013. Exhibit TOJ-14 presents the reports generated by the project during 2013 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 success of the overall management, closeout, and completion of the EPU Project. The number and types of reports changed appropriately as the project progressed through the closeout activities to completion.

Q. Please describe the risk management process used in 2013.

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 Project. 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 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 Nuclear Regulatory Commission (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 2013.

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. 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 and relevant 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. In sum, FPL continued to contract in a careful and strategic manner.

INTERNAL/EXTERNAL AUDITS AND REVIEWS

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

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

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

A. FPSC Staff is conducting two audits related to 2013 EPU activities – a financial audit and an internal controls audit. The 2013 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 2013 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 2013. The results of this review are presented through the testimony of Mr. Albert Ferrer, Vice President of BREI.

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

A. Yes. Experis performed an audit of 2013 expenses at FPL Internal Audit's direction. Specifically, the Experis audit focused on ensuring that costs charged to the EPU Project were for the EPU Project and were recorded in accordance with FPSC Rule 25-6.0423, and included independent testing of expenses charged to the EPU Project for the period January 1, 2013, to December 31, 2013. The Experis audit found that the controls over the EPU Project were good.

"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 Nuclear Cost Recovery Clause (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 Grant-Keene's 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 NCR rule.

Q. Please explain the processes utilized by FPL to ensure that only those costs necessary for the implementation of the Uprate Project were iucluded for NCRC purposes.

A. For the modifications performed, 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. FPL's 2013 EPU activities, and their associated costs, were "separate and apart" as required by the NCR process.

2013 CONSTRUCTION COSTS

Q. What type of costs did FPL incur for the Uprate Project in 2013?

A. As indicated in Exhibit TOJ-1, True-up (T) Schedule T-6 and T-4, and summarized on Exhibit TOJ-15, Summary of 2013 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 2013.

Q. Please describe the costs incurred in the License Application category and the variance, if any, from the 2013 actual/estimated costs in this category.

A. Licensing Costs in 2013 consisted primarily of NRC fees and engineering costs for the NRC review and approval of required revisions to the Alternative Source Term license amendment and plant technical specifications. FPL underestimated the cost of these reviews and incurred $61,271 in this category in 2013, which is $188,232 more than the actual/estimated amount of ($126,960).

Q. Please describe the costs incurred in the Engineering and Design category aud the variance, if any, from the 2013 actual/estimated costs in this category.

A. Engineering and Design Costs consisted primarily of costs for FPL personnel in the FPL engineering organizations at both sites and in the central organization. The majority was oriented towards management, oversight, and review of the detail design activities being performed by the EPC contractor and other contractors. FPL incurred $11.6 million in this category in 2013, which is about $1 million more than the actual/estimated amount. This was primarily attributable to FPL taking on more work internally to enable a more rapid demobilization of vendor personnel.

Q. Please describe the costs incurred in the Permitting category and the variance, if any, from the 2013 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 2013.

Q. Please describe the costs incurred in the Project Management category and the variance, if any, from the 2013 actual/estimated costs in this category.

A. Project Management costs were related to overall project oversight including project and construction management, project controls, and regulatory compliance. These oversight activities were performed by personnel located at both sites, by the EPU central organization, and by non-EPU organizations such as NBO and New Nuclear Accounting. FPL incurred $22.9 million in this category in 2013 which is $3.2 million more than the actual/estimated amount. This variance was attributable to an increase in FPL project management, construction management, and contract management to enable a more rapid demobilization of vendor personnel.

Q. Please describe the costs incurred in the Power Block Engineering, Procurement, etc. category and the variance, if any, from the 2013 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 Turkey Point Unit 4 EPU outage and the continued application of lessons learned in engineering and implementation efforts in completing the EPU Project. FPL incurred $170.8 million in this category in 2013, which is $32.3 million less than the actual/estimated amount. The cost variance is the result of effective project management applying the lessons learned from earlier EPU outages and FPL taking on more work to enable more rapid vendor demobilization and an effective closeout of 2013.

Q. Please describe the costs incurred in the Non-Power Block Engineering, Procurement, etc. category and the variance, if any, from the 2013 actual/estimated costs in this category.

A. Non-Power Block Engineering, Procurement, etc. costs consist primarily of costs for staff and construction craft for facilities restoration and simulator upgrades required to reflect the uprated conditions. FPL incurred $822,166 in this category in 2013. This represents $471,520 more than the actual/estimated amount. The variance is primarily attributable to the work scope associated with site facility restorations to pre-EPU conditions at St. Lucie and Turkey Point Plants, required simulator upgrades, and project closeout activities.

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

A. Recoverable O&M expenses in 2013 were $10.9 million. This represents a variance of $1.1 million more than the actual/estimated amount. Consistent with

FPL's capitalization policy, these expenditures include non-capitalizable commodities, 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 related work, and obsolete inventory write-offs. The variance is primarily attributable to EPU equipment inspections and related work.

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

A. For the period ending December 31, 2013, there were no EPU Project Transmission costs. There was a net credit of $249,371 to the EPU Project primarily due to salvaging of transmission equipment.

Q. Were FPL's 2013 EPU expenditures prudently incurred?

A. Yes. FPL incurred costs of approximately $250 million in 2013. FPL's actual 2013 costs were $10 million less than its previous estimate for the reasons described above. Implementation of the final EPU outage and the extensive project closeout process at both sites were all successfully completed in 2013. 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 2013 EPU management decisions were well-founded and prudent. All costs incurred in 2013 were the product of such decisions, were prudently incurred, and should be approved by the Commission.

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

A. Yes. Exhibit TOJ-1 includes the True-up to Original (TOR) Schedules that I sponsor or co-sponsor providing the total EPU Project cost.

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

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

- Exhibit TOJ-1, 2013 EPU T-Schedules and TOR-Schedules, containing schedules T-1 through T-7B, TOR-6, TOR-6A, and TOR-7, and TOR-2 to be filed in May. Exhibit TOJ-1 contains a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Grant-Keene and myself.
- Exhibit TOJ-2, EPU Project Timeline
- Exhibit TOJ-3, EPU Industry Recognition Awards
- Exhibit TOJ-4, EPU Project Work Force
- Exhibit TOJ-5, EPU Project Benefits at a Glance for FPL Customers
- Exhibit TOJ-6, EPU Investment, Recovery, and Customer Savings from NCR Process
- Exhibit TOJ-7, EPU Project Construction and Completion Photos
- Exhibit TOJ-8, Southeast Florida Reliability Impact
- Exhibit TOJ-9, EPU Project Electrical Output Status
- Exhibit TOJ-10, Illustration of Modifications for Turkey Point Unit 4
- Exhibit TOJ-11, EPU Project Work Activities List
- Exhibit TOJ-12, EPU Equipment Placed In Service in 2013
- Exhibit TOJ-13, EPU Project Instructions Index as of December 31, 2013
- Exhibit TOJ-14, 2013 EPU Project Reports
- Exhibit TOJ-15, Summary of 2013 EPU Construction Costs

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF ALBERT M. FERRER

DOCKET NO. 140009-EI

March 3, 2014

Q. Please state your name and business address.

A. My name is Albert M. Ferrer. My business address is 800 Kinderkamack Road, Oradell, New Jersey 07649.

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

A. I am employed by Burns and Roe Enterprises, Inc. (BREI) as Vice President.

Q. Please describe your educational background and professional experience.

A. I hold an M.S. in Nuclear Engineering from New York University and a B.S. in Mechanical Engineering from Manhattan College, with honors. I have been a Vice President of BREI since 2005 providing management, executive leadership, and oversight for engineering consulting services performed by BREI.

Q. Please describe BREI.

A. BREI is an engineering, procurement, construction, operations, and maintenance company that provides services to private and governmental power industry clients worldwide.

BREI provides engineering, design and consulting services to the nuclear, renewable and fossil power industry. Services provided include owner's engineer, independent engineering, due diligence, acquisition services, uprate analyses, life extension studies, engineering, design, procurement services and construction (EPC) oversight, contract evaluation and EPC project management.

BREI's nuclear experience includes both some of the earliest U.S. commercial nuclear power plants and some of the most recent and innovative nuclear power projects. BREI has been involved in the design of eight commercial nuclear power plants. Additionally, for the use of the U.S. Department of Energy (DOE), BREI performed independent due diligence investigations for new U.S. nuclear plants in support of the DOE's utility loan guarantee project applications. BREI also participated in supporting the development of three combined Construction and Operating License Applications for new nuclear power plants in the southeast U.S.

Q. What was your professional experience prior to BREI?

A. Prior to my employment at BREI, I was Senior Vice President and Managing Director for Stone and Webster, with responsibility for the firm's Strategic Management, Markets and Regulatory, and Project Finance Services practices. During my career at Stone and Webster, I held positions ranging from project engineer to manager of major EPC power plant projects involving site feasibility, environmental impact evaluations, conceptual engineering, detailed design, procurement, cost and estimating, construction engineering, construction management, and start up and testing of a variety of technologies including coal plants, simple cycle and combined cycle gas plants, nuclear plants, geothermal plants, and small hydro facilities. As a project engineer or project manager, I was responsible for cost and scope control, planning, coordinating, scheduling and supervising engineering activities for various nuclear projects, as well as managing major subcontractors with large work forces. I also provided expert testimony at hearings before the Nuclear Regulatory Commission's (NRC) Advisory Committee on Reactor Safeguards involving the construction permit process for nuclear plants.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize an independent review conducted by myself and other BREI senior nuclear power professionals under my direction regarding Florida Power & Light Company's (FPL) execution of the Extended Power Uprate (EPU) related activities during 2013. The purpose of this independent due diligence review was to determine whether FPL's execution of project activities in 2013 was reasonable and prudent. In conducting the review, we applied the prudence standard that has been used by the Florida Public Service Commission (Commission), which is whether FPL's management actions and decisions were within the range of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should have been known, at the time the decisions were made.

Q. Please describe the major areas of your review.

A. BREI reviewed the following areas:

- Project Implementation Scheduling and Organization;
- Close-out Engineering and Design Work Control Process;
- Outage Execution; and
- Close-out Execution.

Q. Please summarize your testimony.

A. Based on the review conducted by the team I lead, FPL's execution of project activities in 2013 was reasonable and prudent. FPL's EPU project management exhibited reasonable and prudent oversight of the EPU project, including oversight of its contractors. Project close-out plans were well developed, planned EPU work was completed on or close to schedule, and power output increases exceeded engineering estimates. Overall, FPL's performance was comparable to, or better than, other large construction projects.

Q. What is the basis for your conclusions regarding FPL's oversight of the EPU project?

A. My conclusions are based on my personal experience gained over the course of my career managing major construction projects and large contracted work forces, as well as my and my team's extensive review of EPU project documentation and personnel interviews. My team was comprised of senior level personnel with experience in nuclear power plant engineering, nuclear plant licensing, nuclear power plant operations and project controls. Our review built upon prior years' reviews, interviews, and site visits. We reviewed project policies and procedures, technical reports, letters, procedures, schedules, cost reports and other project documents. We also reviewed performance metrics (such as key performance indicators), industrial safety reports, corrective action reports, and periodic and special reports to FPL management. In addition, BREI interviewed key EPU project personnel.

Q. Please summarize the conclusions of BREI's review of the EPU project plan, schedule, and organization.

A. FPL prudently managed the EPU project planning and scheduling in 2013. BREI reviewed the processes by which EPU project plans and schedules were developed and revised and determined that FPL used robust project planning and scheduling tools. Additionally, the EPU organization at FPL was appropriately structured to manage the project in an efficient and thorough manner in 2013.

Q. Did BREI review FPL's plans for project close-out?

A. Yes. FPL had developed EPU project close-out plans for both St. Lucie and Turkey Point, including a plan for the disposal of spare or unneeded supplies and equipment. BREI found that the plans addressed the critical elements of a comprehensive close-out program. The plans established a roadmap to close the project with reasonable goals and key milestone dates. They considered lessons learned from other projects and the transition to non-EPU project status.

Q. Please summarize the conclusions of BREI's review of the execution of the EPU outage at Turkey Point Unit 4 that was completed in 2013.

A. FPL succeeded in completing the uprate of its fourth and final nuclear power generating unit in 2013, as planned. Based upon our review, FPL prudently managed the execution of this work. FPL and Bechtel scheduled subcontractors and associated staff to support the outages and subsequently demobilize in a controlled manner.

FPL management appropriately maintained a focus on safety during the execution of the EPU work. FPL also focused on quality and human performance. Bechtel continued to utilize FPL's corrective action program and used it to track and trend issues and to implement corrective actions. Where necessary, resources were added or activities were shifted to others to assure schedules were met.

Q. Did BREI review FPL's incorporation of lessons learned into its 2013 EPU activities?

A. Yes. FPL prudently implemented various cost and time saving lessons learned from the previous outages and closeout activities at Turkey Point and St. Lucie, which have proven to be effective and appropriate. Examples include improvements in the condenser installation sequence, main steam isolation valve assembly process, and outsourcing the drawing update scope of work. These enhancements reduced project cost and helped FPL complete its 2013 EPU project activities on schedule and under budget.

Q. Please summarize the conclusions of BREI's review of project close-ont activities.

A. FPL completed thousands of project close-out activities at both St. Lucie and Turkey Point in 2013, including the methodical demobilization of a large workforce and systematic turnover of the uprated components to the plant operating organization. The Nuclear Regulatory Commission has high expectations related to configuration management which includes the update of final engineering documents, plant drawings, procedures, and other records related to the safe operation of nuclear units. As part of the 2013 close-out process, FPL updated over 40,000 drawings, design basis documents, engineering evaluations, final safety analysis sections, specifications, calculations, and equipment database changes. Based on our review, FPL's close-out activities were performed reasonably and consistent with FPL's close-out plans.

Q. Please summarize your conclusions related to FPL's 2013 EPU project activities.

A. Overall, FPL's management of the EPU project was as good as, or better than, the management of other comparable engineering projects. FPL achieved its objective of completing the EPU project in 2013 by utilizing reliable project planning techniques, effectively managing various separate contractors and a large workforce, implementing lessons learned from prior outages in its final EPU outage, and executing an effective close-out plan.

The Commission should also be aware that FPL's EPU project won major nuclear and construction industry awards. The EPU project won the 2013 Nuclear Energy Institute Top Industry Practice Award and the Power Engineering magazine 2013 Project of the Year – Best Nuclear Project Award, and was a finalist for the 2013 Platts "Construction Project of the Year" Award. The significance of these awards is that FPL's performance of the project was recognized as exemplary in the international nuclear and construction industries.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JOHN J. REED

DOCKET NO. 140009

March 3, 2014

Section I: Introduction

Q. Please state your name and business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Marlborough, Massachusetts 01752.

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

A. I am the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric").

Q. Please describe Concentric.

A. Concentric is an economic advisory and management consulting firm, headquartered in Marlborough, Massachusetts, which provides consulting services related to energy industry transactions, energy market analysis, litigation, and regulatory support.

Q. Please describe your educational background and professional experience.

A. I have more than 37 years of experience in the energy industry, having served as an executive in energy consulting firms, including the position of Co-Chief Executive Officer of the largest publicly-traded management consulting firm in the United States and as Chief Economist for the largest gas utility in the United States. I have provided expert testimony on a wide variety of economic and financial issues related to the energy and utility industry on numerous occasions before administrative agencies, utility commissions, courts, arbitration panels and elected bodies across North America. I also have provided testimony on behalf of FPL in its NCRC proceedings for the last six years. A summary of my educational background can be found on Exhibit JJR-1.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits JJR-1 through JJR-4, which are attached to my direct testimony.

Exhibit JJR-1	Résumé of John J. Reed
Exhibit JJR-2	Expert Testimony of John J. Reed
Exhibit JJR-3	Index of the EPU Project's Periodic Meetings
Exhibit JJR-4	PTN 6 & 7 Project Organization Charts

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to review the benefits of nuclear power and the appropriate prudence standard to be applied to Florida Power & Light's ("FPL" or the "Company") decision-making processes in this Nuclear Cost Recovery Clause ("NCRC") proceeding before the Florida Public Service Commission (the "FPSC" or the "Commission"). In addition, I provide a review of the system of internal controls used by the Company in 2013 during construction phases of the Extended Power Uprate ("EPU") project at the Turkey Point ("PTN") and St. Lucie ("PSL") generating stations (together, the "EPU Project"), and in creating the opportunity to construct two new nuclear generating units ("PTN 6 & 7" or the "New Nuclear Project") at FPL's existing PTN site. Finally, I provide an opinion on whether the EPU and PTN 6 & 7 expenditures for which FPL is seeking recovery in this proceeding have been prudently incurred.

Q. Please describe your experience with nuclear power plants, and specifically your experience with major construction programs at these plants.

A. My consulting experience with nuclear power plants spans more than 30 years. My clients have retained me for assignments relating to the construction of nuclear plants, the purchase, sale and valuation of nuclear plants, power uprates and major capital improvement projects at nuclear plants, and the decommissioning of nuclear plants. In addition to my work at FPL's plants, I have had significant experience with those activities at the following plants:

- Big Rock Point
- Callaway
- Darlington
- Duane Arnold
- Fermi
- Ginna
- Hope Creek
- Indian Point
- Limerick
- Millstone
- Monticello
- Nine Mile Point
- Oyster Creek
- Palisades
- Peach Bottom
- Pilgrim
- Point Beach
- Prairie Island
- Salem
- Seabrook
- Vermont Yankee
- Wolf Creek
- Vogtle

I recently have been active on behalf of a number of clients in pre-construction activities for new nuclear plants across the United States and in Canada. Preconstruction activities I have supported include state and federal regulatory processes, raising debt and equity financing for new projects, and evaluating the costs, schedules and economics of new nuclear facilities. In addition, I have provided nuclear industry clients with detailed reviews of contracting strategies, cost estimation practices, and construction project management.

Q. Please summarize your testimony.

A. The remainder of my testimony covers six main topic areas. Section II contains an introduction to the projects and a brief discussion of the benefits of nuclear power to Florida. Section III describes the appropriate prudence standard that should be applied in this case, and discusses precedent with respect to the prudence standard in Florida. In Section IV, I discuss the internal controls, processes, and procedures that were the focus of Concentric's review. In Section V, I discuss Concentric's assessment of the EPU Project, which added approximately 522 megawatts electric ("MWe") of capacity for FPL's customers across the existing PSL and PTN units, and which drew to a close at the end of 2013. In Section VI, I present Concentric's review of the New Nuclear Project. My conclusions are provided in Section VII. Each of those topics is summarized below.

FPL's four existing nuclear reactors in Florida have provided, and continue to provide, substantial benefits to Florida customers. Those benefits include virtually no air emissions, increased fuel diversity, reduced exposure to fuel price volatility, fuel cost savings, highly reliable base load capacity, and efficient land use. Additional nuclear capacity that has been enabled through the EPU Project and that is being developed in the PTN 6 & 7 Project provides more of those same benefits to Florida.

The rule that governs the Commission's review of FPL's nuclear projects calls for an annual prudence determination. The prudence standard encapsulates three main elements. First, prudence relates to the reasonableness of decisions and actions, not costs incurred by a utility. Second, the prudence standard includes a presumption of prudence with regard to the utility's actions. Absent evidence to the contrary, a utility is assumed to have acted prudently. Third, the prudence standard excludes the use of hindsight. Thus, the prudence of a utility's actions must be evaluated on the basis of information that was known or could have been known at the time the decision was made.

Finally, Concentric has reviewed the processes and procedures that were used to manage and implement the EPU and PTN 6 & 7 projects in 2013. That review has focused on the Company's internal controls that are in place to provide assurance that the Company meets its strategic, financial, and regulatory objectives related to the projects. Our review is premised on a framework developed by Concentric when advising potential investors in new nuclear development projects and our recent regulatory experience.

Q. What are your conclusions with regard to the costs at issue in this proceeding?

A. Concentric has concluded that all of the 2013 costs for which FPL is seeking recovery have been prudently incurred.

<u>**Section II: Introduction to the Projects and Benefits of Nuclear Power to Florida**</u>

Q. Please provide a brief introduction to FPL's EPU Project.

A. FPL recently completed the EPU Project at PSL and PTN. The EPU Project modified and upgraded specific components at all four operating units at PSL and PTN in order to increase the maximum power level at which the two stations can operate. In total, the EPU Project increased the nuclear generating capacity of PSL and PTN by 522 MWe for FPL's customers, which is 123 MWe greater than the original plan of 399 MWe for the EPU Project.

Q. Please generally describe PTN 6 & 7.

A. The PTN 6 & 7 Project remains focused on obtaining the licenses and permits that will provide FPL and its customers the option to construct two nuclear units at the existing PTN site. Specifically, through PTN 6 & 7, FPL continues to create the opportunity to construct approximately 2,200 MWe of new nuclear capacity. The Company's project management strategy remains focused on preserving flexibility and maintaining periodic hold points and off-ramps during which PTN 6 & 7's progress can be delayed for further analysis or progressed to more advanced stages of development. At each major hold point a decision on whether to move forward with development will be made based on the project's ability to achieve a balance of high value to customers and decreased exposure to risk. Once the project has obtained all relevant permits and its Construction and Operating License ("COL") from the Nuclear Regulatory Commission ("NRC"), the option to construct will last for a period of at least 20 years.

Q. Has nuclear power benefited FPL customers?

A. Yes it has. Nuclear power continues to play a crucial role in FPL's power generating fleet. The four reactors at FPL's existing PSL and PTN sites have been in operation for an average of over 37 years. Throughout almost four decades, these units have provided numerous and substantial benefits to Florida customers by reliably producing carbon-free energy, enhancing fuel diversity and insulating customers from commodity price spikes.

Q. Is it prudent to continue the development of additional nuclear capacity in Florida?

A. Yes. It is prudent to continue the development of additional nuclear capacity in Florida to the degree that the capacity can be developed on an economic basis over its full life-cycle.

Q. What are the advantages of using nuclear power as a base load energy source?

A. One of the greatest advantages to additional nuclear power is that it has virtually no carbon dioxide emissions. Unlike alternative, carbon-intensive base load sources in Florida, nuclear energy does not burn fossil fuels and, therefore, emits no greenhouse gases ("GHG"). Based on FPL's 2012 generation data and the Environmental Protection Agency's ("EPA") eGrid tool, the four nuclear units FPL operates in Florida currently avoid between seven and eight million tons of CO_2 emissions per year compared to an average natural gas-fired, combined cycle generating station.[1] The magnitude of avoided emissions is even greater when compared to other carbon-based fuels (*e.g.*, oil, coal) assuming each fuel is used to produce the same amount of energy.

In addition to its environmental benefits, nuclear power provides a vital source of diversification to the electric generation mix. In recent years, Florida has become increasingly dependent on natural gas as a fuel source for electric generating facilities. According to the Florida Reliability Coordinating Council's 2013 Load and Resource Plan, natural gas generated more net energy for load in 2012 than all other fuels combined in Florida. By 2022, natural gas generation could approach 58.8%.[2] In order to mitigate the incremental dependence on natural gas, utilities in the state should continue to develop alternatively-fueled facilities. This will help limit the state's exposure to natural gas price spikes and potential supply disruptions.

Q. How does the current price of natural gas compare with recent trends in natural gas prices?

A. Although the price of natural gas is currently on the low end of what we have observed in recent years, it is naturally subject to price changes. From 2002-2008 spot natural gas prices at Henry Hub rose from approximately $2.50 to over $14.00 per million British Thermal Units ("MMBtu")[3] before falling to current levels in response to new supply discoveries and advances in technologies used to recover gas from shale formations. The price of natural gas at the Henry Hub, a common trading location, fell to approximately $2 per MMBtu in July 2012 but has since increased to approximately $4 per MMBtu. While even the current wholesale price of natural gas remains below historical levels, it is important to consider the long-term outlook when evaluating the benefits of resource diversity over the anticipated 60-year life-span of a nuclear facility.

Q. What factors could affect the market for natural gas?

A. There are a number of factors that could have a significant impact on the market for natural gas, including the export of natural gas in the form of liquefied natural gas ("LNG"). There are a number of LNG export facilities at various stages of permitting and development in North America. These export terminals are being developed to serve the considerable demand for natural gas from markets outside the country. If and when the terminals enter service, the volume of gas flowing through them could significantly affect the domestic market for gas both as a source of home heating and for power generation and industrial use.

It is conceivable that incremental demand from export terminals can be met by increases in the development of natural gas resources in the shale formations throughout the United States. However, at this early stage we are already seeing changes in the flow of gas along major interstate pipelines, which could affect the regional market for natural gas. Natural gas to serve Florida currently comes largely from resources in Texas and the Gulf of Mexico, but is expected to come from resources in the Marcellus Shale in the near future as additional infrastructure to bring gas resources to the state come online.

Q. How does resource diversity benefit customers in Florida?

A. Resource diversification provides numerous benefits to Florida residents by mitigating exposure to any single fuel source. This concept, as explained in modern portfolio theory, is based on the idea that a group of diverse assets may collectively lower the risks relative to holding any individual asset or type of asset. Diversification of fuel sources—through added nuclear power and additional renewables—insulates consumers from commodity price fluctuations and reduces the risk profile of Florida's electric generation mix.

Diversification through pursuit of the option to construct new base load alternatives to natural gas is particularly important in the wake of decisions to permanently retire nuclear facilities and to halt development of new nuclear units outside of FPL's system.

Q. Is it appropriate for the Commission to continue to allow recovery of costs, including carrying costs, through the annual NCRC process?

A. Yes. It is appropriate to allow for cost recovery through the annual NCRC process given the magnitude of the potential benefits of additional nuclear capacity. The NCRC is important for both the Company and its customers. It provides FPL's debt and equity investors with some measure of assurance concerning cost recovery if their investments are used to prudently incur costs. In addition, by permitting recovery of carrying costs associated with construction, the NCRC eliminates the effect of compound interest on the total project costs, which will reduce customer bills when the facilities are fully implemented.

Q. Are there benefits of nuclear power other than those that quantitatively affect the price of electricity?

A. Yes. One benefit of nuclear generation that is often overlooked is its relatively small footprint compared to other clean, emissions-free technologies. Nuclear power plants require less land, and thus limit the degree of forest clearing, wetlands encroachments, and other environmental impacts associated with siting a generating facility.

<u>Section III: The Prudence Standard</u>

Q. Please generally describe the prudence standard as you understand it.

A. The prudence standard is captured by three key features. First, prudence relates to actions and decisions. Costs themselves are neither prudent nor imprudent. It is the decision or action that must be reviewed and assessed, not simply whether the costs are above or below expectations. The second feature is a presumption of prudence, which is often referred to as a rebuttable presumption.

The burden of showing that a decision is outside of the reasonable bounds falls, at least initially, on the party challenging the utility's actions. The final feature is the total exclusion of hindsight. A utility's decisions must be judged based upon what was known or knowable at the time the decision was made by the utility.

Q. What test for prudence has been adopted by the Commission?

A. The Commission has prohibited the use of hindsight when reviewing utility management decisions and has instead chosen to strictly follow the standard I described above. In 2013, the Commission reaffirmed this approach, referring to its "longstanding practice" (Order No. PSC-13-0493-FOF-EI):

> [T]he standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should have been known, at the time the decision was made.

As the Commission notes in the Order in last year's NCRC proceeding, this same standard has been applied consistently since 2007.

<u>Section IV: Framework of Internal Controls Review</u>

Q. What is meant by the term "internal control" and what does it intend to achieve?

A. Internal control is a process used by organizations to provide a reasonable assurance of the effectiveness of operations, the reliability of financial reporting, and compliance with applicable laws and regulations. Internal controls inform decision-making by tracking the organization's performance relative to its various objectives. Internal control is a process that responds to the dynamic nature of organizations and projects over time. Finally, internal control can provide only reasonable assurance. Expectations of absolute assurance cannot be achieved.

Q. Please describe the framework Concentric used to review the Company's system of internal control as implemented by the EPU Project and PTN 6 & 7 in 2013.

A. As in prior years, Concentric focused on six elements of the Company's internal controls:

- Defined corporate procedures;
- Written project execution plans;
- Involvement of key internal stakeholders;
- Reporting and oversight requirements;
- Corrective action mechanisms; and
- Reliance on a viable technology.

Each of these elements was reviewed for the following five processes:

- Project estimating and budgeting processes;
- Project schedule development and management processes;
- Contract management and administration processes;
- Internal oversight mechanisms; and
- External oversight mechanisms.

Concentric's work in this proceeding is additive to our work reviewing the projects in prior years. In other words, Concentric's review of the EPU Project's and PTN 6 & 7's 2013 activities incorporates the information and understanding of the projects gained during Concentric's reviews of FPL's activities from 2008 through 2013.

Q. Please describe how Concentric performed this review.

A. Concentric's review was performed over the period from December 2013 to February 2014. We began by reviewing the Company's policies, procedures and instructions with particular emphasis placed on those policies, procedures or instructions that may have been revised since the time of Concentric's previous review. In addition, Concentric reviewed the current project organizational structures and key project milestones that were achieved in 2013. Concentric then reviewed other documents and conducted in-person interviews of more than 20 FPL personnel to make certain the EPU Project's and PTN 6 & 7's policies, procedures and instructions were known by the project teams, were being implemented by the projects and have resulted in prudent decisions based on the information that was available at the time of each decision.

Concentric's interviews included representatives from each of the following functional areas:

- Project Management;
- Project Controls;
- Integrated Supply Chain Management ("ISC");
- Employee Concerns Program;
- Quality Assurance/Quality Control ("QA/QC");
- Internal Audit;
- Transmission;
- Environmental Services; and
- Licensing and Permitting.

Q. Please describe why you believe it is important for FPL to have defined corporate procedures in place throughout the development of the projects.

A. Defined corporate procedures are critical to any project development process as they detail the methodology with which the project will be completed and make certain that business processes are consistently applied to the project. To be effective, these procedures should be: (1) documented with sufficient detail to allow project teams to implement the procedures; (2) clear enough to allow project teams to easily comprehend the procedures; and (3) revisited and revised as the project evolves and as lessons are learned. It is also important to assess whether the procedures are known by the project teams and adopted into the Company's culture, including a process that allows employees to openly challenge and seek to improve the existing procedures and to incorporate lessons learned from other projects into the Company's procedures. Within the EPU Project and PTN 6 & 7, the Project Controls staff is primarily responsible for ensuring the Company's corporate procedures are applied consistently by the various FPL and contractor staff members who are working on the projects. However, it is acknowledged that this is a shared responsibility held by all project team members, including the project managers.

Q. Please explain the importance of written project execution plans.

A. Written project execution plans are necessary to prudently develop a project. These plans lay out the resource needs of the project, the scope of the project, key project milestones or activities and the objectives of the project. These documents are critical as they provide a "roadmap" for completing the project as well as a "yardstick" by which overall performance can be monitored and managed. It is also important for the project sponsor to require its large-value contract vendors to provide similar execution plans. Such plans allow the project sponsor to accurately monitor the performance of these vendors and make certain at an early stage of the project that each vendor's approach to achieving key project milestones is consistent with the project sponsor's needs. These project plans must be updated to reflect changes to the project scope and schedule as warranted by project developments.

Q. Why is it important that key internal stakeholders are involved in the project development process?

A. One of the most challenging aspects of prudently developing a large project is the ability to balance the needs of all stakeholders, including various Company representatives and the Company's customers. This balance is necessary to make certain that the maximum value of the project is realized. By including these stakeholders in a transparent project development process and by continuing to engage stakeholders throughout the execution of the project, key project sponsors will be better positioned to deliver on high-value projects.

Q. Why is it important to have established reporting and oversight requirements?

A. Effective internal and external communications enable an organization to meet its key objectives, and allow employees to effectively discharge their responsibilities. By having an established reporting structure and periodic reporting requirements, the project sponsor's senior management will be well-informed of the status of the project's various activities. Reporting requirements give senior management the information it needs to use its background and previous experience to prudently direct the many facets of the project. In addition, established reporting requirements ensure that senior management is fully aware of the activities of the respective project teams so management can effectively control the overall project risks. In the case of the EPU Project and PTN 6 & 7, this level of project administration by senior management is prudent considering the large expenditures required to complete the projects and the potential impact of the projects on the Company overall.

In order to be considered robust, these reporting requirements should be frequent and periodic (*i.e.*, established daily, weekly and monthly reporting requirements) and should include varying levels of detail based on the frequency of the report. The need for timely and effective project reporting is well recognized in the industry. A field guide for construction managers notes:

> Cost and time control information must be timely with little delay between field work and management review of performance. This timely information gives the project manager a chance to evaluate alternatives and take corrective action while an opportunity still exists to rectify the problem areas.[4]

Q. What is the purpose of corrective action mechanisms and why are they important to ensure the Company is prudently incurring costs?

A. A corrective action mechanism is a defined process whereby a learning culture is implemented and nurtured throughout an organization to help eliminate concerns that can interfere with the successful completion of the project. Corrective action mechanisms help identify the root cause of issues, such as an activity that is trending behind schedule, and provide the opportunity to adopt mechanisms that mitigate and correct the negative impact from these issues. A robust corrective action mechanism assigns responsibility for implementing the corrective actions and a means by which these activities are managed. In addition, a corrective action mechanism educates the project team in such a manner as to ensure project risks are prudently managed in the future.

Q. Are there any other elements of the Company's internal controls included in your review?

A. No. There were no other elements of the Company's internal controls included in my review.

Section V: EPU Project Activities in 2013

Q. How is this section of your testimony organized?

A. This section describes my review of the five key processes (*i.e.*, project estimating and budgeting, project schedule development and management, contract management and administration, internal oversight mechanisms, and external oversight mechanisms), described above, as they related to the EPU Project in 2013.

Q. As a preliminary matter, what did your review lead you to conclude with regard to the prudence of FPL's actions in 2013 as they related to the EPU Project?

A. FPL's decision making and management actions as they related to the costs for which FPL is seeking recovery for the EPU Project in 2013 were prudent, and it is thus my opinion that FPL's 2013 expenditures on the EPU Project were prudently incurred. The Company's decisions and actions in 2013 included management of the final EPU implementation outage at PTN Unit 4, which included incorporation of lessons learned from earlier outages, and execution of the necessary closeout activities at PSL and PTN to ensure the continued safe and reliable operation of FPL's nuclear facilities. The result of FPL's oversight of the EPU Project in 2013 was that all activities necessary to close out the project were performed, and the EPU Project was completed.[5]

Q. What period of time did your review of the EPU Project encompass?

A. Concentric's review of the EPU Project was for the period January 1, 2013 through December 31, 2013. Concentric's review of this time period relied upon data that was provided to Concentric in the period from December 2013 to February 2014.

Q. What were the main phases of the EPU Project, and in which phase was FPL in 2013?

A. The EPU Project consisted of four overlapping phases: (1) the Engineering Analysis Phase; (2) the Long Lead Equipment Procurement Phase; (3) the Engineering Design Modification Phase; and (4) the Implementation Phase. Following the implementation of nuclear upgrades, nuclear plant operators must also undertake activities to close out construction projects before those projects can be considered completed and to ensure continued safe operations.

The Engineering Analysis, Long Lead Equipment Procurement, and the Engineering Design Modification Phases were completed prior to 2013. In the Implementation Phase, the final EPU implementation outage at PTN Unit 4, which began in 2012, was completed. In addition, FPL performed the closeout activities necessary to complete the EPU Project. The activities undertaken in 2013 are further described in the testimony of FPL Witness Jones.

Q. As of the end of 2013, what activities remain in the EPU Project?

A. No activities remain in the EPU Project as of the end of 2013. The majority of closeout activities at PSL and PTN were completed in 2013 while the remaining activities were transferred from the EPU Project organization to the respective plant organizations for completion in 2014.

Q. How was the EPU Project organized in 2013?

A. At the beginning of 2013, there remained in place much of the same EPU organizational structure at PTN as the Company had in 2012 in order to oversee the final implementation outage at that plant. That structure included an EPU Site Director at PTN to oversee construction, project controls, licensing, procurement, and other critical functions, as well as an EPU Implementation Owner at FPL's headquarters in Juno Beach. In addition to the Implementation Owner, there remained a centralized core project management team in Juno Beach providing oversight of the EPU Project from FPL's headquarters, as well as a Quality Assurance ("QA") Manager, whose function necessarily acted separately from the core team to maintain independence when assessing the EPU Project. After the completion of the PTN outage, project staffing began to ramp down according to FPL's staffing plan.

Project Estimating and Budgeting Processes

Q. Please describe the mechanisms utilized to track the project's budgets and cost estimate in 2013.

A. Several budget and cost reporting mechanisms continued to be used in 2013 to ensure that key decisions related to the EPU Project were prudent and made at the appropriate level of FPL's management structure. Those reporting mechanisms included presentations and status calls as well as periodic reports that allowed the Company to leverage the experience of its executive team. Those reports included the Monthly Operating Performance Report that categorized the overall performance of the EPU Project as either on budget, budget-challenged, or out of budget. Each site also continued to produce monthly cash flow reports in 2013 that contained monthly actual capital expenditures as compared to the budget, and explanations of any increases or decreases. Those reports were reviewed and discussed during formal project management meetings.

As the Implementation Phase of the EPU Project was completed, certain meetings and reports were no longer necessary, and thus were no longer undertaken by FPL, while other meetings and reports were added to track closeout activities to completion. A list of the EPU Project's periodic meetings can be found in Exhibit JJR-3, and a list of the reports used to monitor the EPU Project's cost performance can be found in the testimony of FPL Witness Jones as Exhibit TOJ-14.

Q. In 2013, how did the EPU Project track and identify risks to the project's budgets and cost estimate?

A. Through the end of the Implementation Phase, the EPU Project continued to use a risk matrix, referred to as the "Risk Register," to track challenges to the current budgets and cost estimate and to provide a brief explanation of the reasons for the challenges. According to EPPI-340, "EPU Project Risk Management Program," the risk identification process covered identification, assessment and analysis, handling strategy, risk management, categorization, reporting, and mitigation. The Company defined risks as issues that affect nuclear quality, environment, project cost, schedule, safety, security, legal, plant operations, regulatory, and reputation.

Q. What steps did FPL take to control the costs of the EPU Project in 2013?

A. FPL continued to work closely with its vendors to focus them on productivity, safety, and performance. The Company also monitored its EPU Project closeout activities to keep those activities on budget. In addition, in 2012, the Company had sought and obtained concessions from vendors that worked on the EPU Project, including reductions in labor rates and daily living allowances, as well as the elimination of the EPC vendor's (*i.e.*, Bechtel's) incentive fee. Those negotiations resulted in additional concessions by the vendors in 2013. Lastly, FPL incorporated lessons learned both in 2013 and throughout the EPU Project to improve the project as it progressed, and to prevent recurrence of emergent issues. In 2013, that incorporation of lessons learned was evidenced by the reduced cost and schedule that was required to complete the final PTN Unit 4 implementation outage as compared to the final PTN Unit 3 implementation outage, following similar results at PSL Units 1 and 2.

Q. Did Concentric review the process by which the EPU Project team made certain that each plant modification or component replacement is necessary for the completion of the EPU Project?

A. Yes, Concentric reviewed the process by which FPL made certain that the costs being charged to the EPU Project in 2013 were separate and apart from the normal maintenance and operations of PSL and PTN, and, therefore eligible for recovery under the NCRC. That process was previously reviewed and approved by the Commission.[6]

Q. Did the EPU Project perform an analysis of its cost effectiveness in 2013?

A. No. While FPL performed a review and update to its cost estimate in 2013 in adherence with FPL procedure EPPI-302, "Nonbinding Cost Estimate Range," no further feasibility analysis was necessary due to the completion of the project. In terms of the nonbinding costs estimate, FPL updated its cost estimate for direct EPU Project costs from a range of $2.96 billion to $3.15 billion to a point estimate of approximately $3.40 billion, which reflected changes based on the final EPU implementation outages.

Q. What is your conclusion with regard to the EPU Project's processes used to track cost performance in 2013?

A. My conclusion is that the EPU Project continued to use a robust set of policies and procedures to track and control cost performance, and that those policies and procedures were appropriate for the final year of implementation and closeout.

Project Schedule Development and Management Process

Q. How did the EPU Project team monitor its schedule performance in 2013?

A. In 2013, the EPU Project team continued to utilize daily, weekly, bi-weekly, monthly, and quarterly conference calls and meetings. Presentations and reports were developed to facilitate many of these conference calls and meetings. Exhibit JJR-3 provides a listing of the meetings used in 2013 to monitor the EPU Project's schedule performance, and a list of the reports used to monitor the

EPU Project's schedule performance can be found in the testimony of FPL Witness Jones as Exhibit TOJ-14.

Q. With the EPU Project moving into the closeout stage, what reports did FPL use to track closeout activities?

A. FPL developed closeout plans for both sites that provided a roadmap for closeout activities. Those plans described the "end state" that the Company sought to achieve with regard to each site, along with the necessary activities to reach that goal. Importantly, the closeout plans included lessons learned from NextEra's nuclear fleet, along with PTN and PSL's response to those lessons.

With the completion of the implementation outages, FPL also continued to use a project closeout dashboard report and closeout metrics package that it created in 2012 to track project closeout activities such as engineering change package closeouts, procedure revisions, training material revisions, and purchase order and contract closeouts. Those reports were reviewed approximately weekly.

Q. Did the EPU Project use any other methods to monitor schedule performance in 2013?

A. Yes. FPL continued to use an industry standard software package known as Primavera P6 Professional Project Management to review the project schedule based on approved updates on an almost real-time basis.

Q. What status reports did the EPU Project's key vendors provide to the Company?

A. In addition to monitoring the EPU Project team's efforts, the Company also required that status reports be provided by its key vendors in 2013. Specifically, the vendors were responsible for providing daily, weekly, and monthly progress reports regarding their schedule. During the final implementation outage at PTN Unit 4, vendors were required to provide status updates on a daily basis. As vendors demobilized from the project sites after the Implementation Phase, their reporting to FPL was no longer necessary.

Q. How did the EPU Project track and identify risks to the project schedule?

A. In 2013, the EPU Project continued to use the same Risk Register, described earlier, to track challenges to the current schedule and to provide a brief explanation of the reasons for the challenges. Bechtel, the EPC contractor, also provided FPL with a "Trend Log" to track risks to the schedule. The Trend Log was integrated into the Risk Register.

Q. Was the project schedule altered in 2013?

A. No, the overall EPU Project implementation schedule was not altered in 2013. While the final implementation outage at PTN Unit 4 took approximately five days longer than originally planned, that outage was 15 percent shorter in duration than the final PTN Unit 3 outage, and the EPU Project was completed in 2013 as anticipated.

Q. Please describe Concentric's observations related to the EPU Project's schedule development and management in 2013.

A. Concentric observed that FPL had sufficient systems and procedures in place to allow for appropriate oversight of the project schedule development and management process. In addition, the Company appropriately integrated new reporting mechanisms to track and complete the many closeout activities necessary to complete the EPU Project.

Contract Management and Administration Processes

Q. What was the focus of FPL's contracting activities in 2013 related to the EPU Project?

A. In 2013, FPL was focused on working with vendors to complete the final implementation outage at PTN Unit 4 and to perform closeout activities, as well as closing out the contracts it had entered into over the course of the EPU Project.

Q. In 2013, what processes were used to ensure the EPU Project was prudently managing and administering the Company's procurement functions?

A. The procurement function continued to be governed by several well-defined policies and procedures in 2013. Those policies continued to be administered through the ISC organization and included a significant breadth and depth of procurement processes, including a stated preference for competitive bidding wherever possible, the proper means for conducting a comprehensive solicitation, initial contract formation, and administration and close out of the contract.

Q. Were there cases in 2013 when contracts were executed without first having gone through a competitive bidding process?

A. Yes. While fewer in number in 2013 than in prior years due to the stage of the EPU Project, certain situations called for the use of single source procurement methods. The reasons for that included the fact that there are very few suppliers qualified to handle the vast amount of proprietary technical information relied upon when operating or working on a nuclear plant. Additionally, single sourcing is appropriate in certain situations that involve leveraging existing knowledge or expertise or otherwise capitalizing on synergies.

Q. What process did FPL use to close out its EPU contracts at the completion of the project?

A. The contract close out process involved the collaboration of several FPL departments, including ISC and Project Controls, to perform the necessary activities to ensure that all requirements of the contract had been met in order for ISC to mark the contract as closed and completed in FPL's asset management system. Those activities included verification of receipt of all deliverables, completion of work, verification that all invoices had been received and paid, and resolution of outstanding change requests or claims.

Q. What process was used in 2013 to make certain that the Company and its customers received the full value of the various contracts for services and materials?

A. FPL continued to utilize an invoice review process to make certain that the Company and its customers received the full value of the goods and services being procured for the EPU Project. That process required a review of each invoice by key project team members who worked closely with the vendor on the goods and services for which payment was requested to make certain that the costs being billed were correct and appropriate. Each invoice review required approval by certain senior project team members based upon the individual's corporate approval authority. That tiered oversight structure, including technical specialists who were most familiar with the contracted work, ensured that the

EPU Project's procured goods and services provided their full value to the Company and its customers.

Q. Does Concentric have any observations and recommendations related to the processes used to manage the EPU Project's procurement functions in 2013?

A. Yes. Overall, Concentric noted that the EPU Project's procurement functions performed quite well in 2013. FPL continued to apply robust procedures to its purchasing activities, and worked to close out the significant number of contracts required for the EPU Project.

Internal Oversight Mechanisms

Q. What mechanisms exist for internal oversight and review of the EPU Project?

A. There continued to be several mechanisms used to make certain the EPU Project received adequate oversight in 2013. First, the Company has in place senior oversight and management committees, including the Board of Directors, the Nuclear Committee on the Board of Directors, and the Company's Nuclear Review Board. FPL also had an On-Site Review Group at PTN during the final implementation outage. Second, the Company's senior management received a briefing on the EPU Project on a periodic basis while the Company's Chief Nuclear Officer ("CNO") received regular briefings, including during the closeout process.

The EPU Project was also subject to an annual review by the FPL Internal Audit Department, and the FPL QA/QC Department was responsible for making certain that the FPL QA program was being implemented by the EPU Project team. The FPL Employee Concerns Program ("ECP") provided FPL employees and contract workers with the ability to confidentially express concerns related to the EPU Project.

Lastly, FPL transferred operational experience from NextEra's nuclear fleet to the EPU Project. That internal transfer of knowledge allowed FPL to benefit from lessons learned within NextEra that resulted in improved efficiency in the implementation of the EPU Project and during closeout activities.

Q. Please describe the Internal Audit Department and its functions.

A. The internal audit process was a backstop to make certain the EPU Project complied with the Company's internal policies and procedures. The Internal Audit Department did not report to any of the EPU Project team members in order to protect the Internal Audit Department's employees' independence. Rather, Internal Audit reported administratively to the Senior Vice President of Internal Audit and Compliance (who reported directly to the Chairman and CEO of NextEra Energy), and functionally to the Audit Committee of the Board of Directors.

Q. Did the Internal Audit Department complete any audits in 2013?

A. Yes. FPL's Internal Audit Department completed several audits in 2013. Although I have reviewed these, I will not be discussing them in my testimony because the Company maintains confidentiality with respect to these audits.

Q. Did those audits result in findings that were adverse to FPL's application of its procedures and management of the EPU Project?

A. No. While Internal Audit typically issues findings and recommendations as part of its audits, the findings and recommendations did not indicate imprudent management by FPL, and FPL took steps to address those findings to improve its oversight of the project. As I described above, Internal Audit acted as a backstop to the EPU's project controls functions, and its investigations and findings allowed the project to address issues of human performance and, in some instances, further improve upon its procedures.

Q. Is Internal Audit conducting a review of the EPU Project costs charged in 2013?

A. Yes. Costs incurred by the EPU Project in 2013 were reviewed by the Company's Internal Audit Department. The Department's final report was issued in February 2014 with no significant findings. Internal Audit performed a similar review in 2013, which also had no significant findings.

Q. Please describe the FPL QA/QC function and its purpose.

A. In 2013, the FPL QA/QC employees were responsible for implementing the Company's QA Program that was mandated by the NRC in 10 CFR 50, Appendix B. The QA/QC function was separate from the EPU Project and reported to the Company's CNO through the Director of Nuclear Assurance. Federal regulations define eighteen criteria for an NRC licensee's QA program. It was the responsibility of the QA/QC employees to ensure that FPL's QA program met those criteria.

Q. What QA activities related to the EPU Project took place in 2013?

A. The QA/QC function oversaw the completion of the Implementation Phase of the EPU Project. The QA/QC evaluators were also responsible for reviewing certain activities by the EPU Project's vendors, both at the EPU Project sites as well as at certain vendors' manufacturing facilities. Those activities included in-person reviews of the project vendors' methodologies, qualifications and QA programs. Finally, the QA/QC evaluators monitored NRC QA activities and suggested changes to the EPU Project in order to respond to the NRC's findings at other power uprate projects.

Q. Please describe the FPL ECP and its purpose.

A. The FPL ECP is a confidential process through which employees and contractors can raise concerns regarding nuclear safety and hostile work environments, among other issues. ECP has a physical presence at both PSL and PTN, and ECP coordinators conducted outreach in order to educate employees and contractors about the existence of the program. ECP personnel perform investigations of employee concerns as necessary. The ECP does not advocate on behalf of employees, but rather serves as an impartial reviewer and investigator of issues in order to bolster a safe work environment.

Q. What internal operational experience did FPL incorporate into the EPU Project in 2013?

A. In 2013, FPL incorporated operational experience learned from other plants within NextEra's nuclear fleet in order to effectively perform close out activities at the facilities. That operational experience was incorporated directly into FPL's closeout plans for PSL and PTN.

Q. Please provide Concentric's observations related to the internal oversight and review mechanisms utilized in 2013.

A. FPL had in place the appropriate internal oversight and audit functions to properly manage and survey the EPU Project, including processes to address emerging issues and perform closeout activities. Those are important functions to have within a mega project organization to ensure prudent execution of the project.

External Oversight Mechanisms

Q. What external oversight mechanisms did the Company utilize in 2013 to ensure the EPU Project had adequate internal controls and was prudently incurring costs?

A. As in prior years, there were several external oversight and review mechanisms in place for the EPU Project. Those oversight and review mechanisms included the retention of my firm, Concentric, to perform the review described in this testimony, ongoing contact with the project's major vendors' quality oversight functions, industry contacts, and the FPSC Staff's financial and internal controls audits. Additionally, as a publicly-traded company, NextEra Energy must undergo an annual company-wide audit of its financial and internal controls.

Q. In 2013 did industry contacts provide a form of external oversight and review?

A. Yes. FPL is a member of several industry groups, including the Institute of Nuclear Power Operations, the World Association of Nuclear Operators, the Electric Power Research Institute and Nuclear Energy Institute ("NEI"), among others, which provided further guidance about uprate projects. Each of those groups provided the EPU Project team with access to a wide breadth and depth of information that was used to enhance the project team's effectiveness. Additionally, relationships that the EPU Project team members have with their counterparts at other nuclear power plants around the country allowed the EPU Project team to benefit from operating and construction experience at other plants and incorporate that experience into the planning, implementation, and closeout at PSL and PTN.

Q. Did Concentric have any observations related to external oversight and review of the project in 2013?

A. During its review, Concentric noted that FPL appeared to have taken reasonable steps to obtain and implement lessons learned from outside sources in 2013. These lessons learned were vital to the successful execution of the projects.

<u>Section VI: PTN 6 & 7 Project Activities in 2013</u>

Q. How is this section of your testimony organized?

A. This section describes Concentric's review of the five key processes (*i.e.*, project estimating and budgeting, project schedule development and management, contract management and administration, internal oversight mechanisms, and external oversight mechanisms) as they were applied to PTN 6 & 7 in 2013.

Q. As a preliminary matter, what did your review lead you to conclude with regard to the prudence of FPL's actions in 2013 on the PTN 6 & 7 Project?

A. FPL's decision to continue pursuing PTN 6 & 7 in 2013 was prudent and was expected to be beneficial to customers. In addition, Concentric's review indicates that FPL's management of the PTN 6 & 7 Project over the course of 2013 has resulted in prudently-incurred costs. During 2013, FPL continued its methodical approach to achieving its licensing goals, which will allow it to continue to create the option to build new nuclear capacity for the benefit of its customers.

Q. How was PTN 6 & 7 organized in 2013?

A. Since 2008, few changes have occurred in the PTN 6 & 7 Project organization, and no changes were made in 2013. The 2013 PTN 6 & 7 organizational structure is depicted in Exhibit JJR-4. The project continues to be developed within two separate, but collaborative business units: Project Development and New Nuclear Projects. While both organizations ultimately report through the same executive management chain, their objectives are tied to each group's respective capabilities. That approach allows FPL to ensure the most qualified group is utilized to accomplish the project's objectives.

The Project Development organization was responsible for all aspects of the project not related to the NRC in 2013, while the New Nuclear Projects organization remains responsible for submitting and defending the PTN 6 & 7 Construction and Operating License Application ("COLA"). The New Nuclear Projects organization will also be responsible for the engineering, procurement, construction, and subsequent start-up of the project if a decision to proceed is ultimately made.

Q. Were there any changes in executive responsibility for the PTN 6 & 7 project in 2013?

A. In March 2013, the New Nuclear Projects and Project Development organizations were moved from the Engineering and Construction organization to the Nuclear Division within FPL, which is led by the Company's CNO. This change was made to reflect the project's current focus on licensing and development of the option to construct the new units. It is anticipated that the project will transition back into the Engineering and Construction organization if and when a decision is made to move beyond the licensing phase of the project.

Q. In 2013, who was responsible for the New Nuclear Projects organization?

A. The CNO was supported directly by a Licensing Director who manages the New Nuclear Projects organization. The Licensing Director was supported by multiple Licensing Engineers and Document Control personnel, as well as by a matrix relationship to other departments within FPL.

Q. Who was responsible for the Project Development organization in 2013?

A. The Project Development organization is led on a day-to-day basis by a Senior Director of Development who was supported via matrix relationships by a variety of FPL functional departments.

Q. What internal FPL departments supported the New Nuclear Projects and Project Development organizations in 2013?

A. Both organizations received support from FPL's Juno Environmental Services, Law Department, and ISC, among others.

Q. Did Concentric have any observations related to the PTN 6 & 7 organizational structure in 2013?

A. Yes. Concentric believes the organizational structure appropriately assigned responsibility to those employees best equipped to respond to the project needs and properly reflected the project's focus on the licensing and permitting stage that the project is currently in.

Q. What major milestones were achieved by PTN 6 & 7 in 2013?

A. The main focus of the New Nuclear Project in 2013 was to continue to make progress with federal and state licensing reviews. To that end, PTN 6 & 7 achieved several important milestones during the year.

The project's state Site Certification Application ("SCA") was the subject of nearly eight weeks of hearings beginning in July, and extending into October. In early December 2013, the Administrative Law Judge ("ALJ") hearing the case issued a recommended order, stating that the Siting Board should grant final certification to FPL for PTN 6 & 7and approve its proposed eastern and western transmission lines (*i.e.*, the East Preferred Corridor and West Consensus Corridor/MDLPA #2). A final order is expected from the Siting Board in March 2014.

At the federal level the project continued to respond to Requests for Additional Information ("RAIs") from the NRC as that agency's staff reviews the PTN 6 & 7 COLA. FPL provided responses to the NRC's RAIs regarding seismic issues, geotechnical engineering, and the alternate site analysis. The Company also participated in a series of public meetings between April and November 2013 to discuss the NRC's concerns.

In addition, the PTN 6 & 7 project received zoning approval for plant structures from Miami-Dade County in January 2013.

Q. Were there changes in 2013 that affect expectations for the timing of future regulatory approvals?

A. Yes. The project expected to receive an updated licensing review schedule in 2013, but the NRC has not yet issued a revision. Because of the shutdown of the federal government in the fall of 2013, expectations with respect to the waste confidence rule, which I discuss in greater detail below, have been extended by at least one month.

In addition, delays with respect to the SCA have resulted in the Site Certification Board Meeting being moved to March 2014 from December 2013.

Q. Do challenges facing the NRC affect the PTN 6 & 7 Project?

A. Yes. The NRC was presented with two significant challenges in 2011 that I have discussed in prior years and that continue to affect the nuclear industry. In March 2011, the earthquake near Japan's Fukushima Daiichi Nuclear Generating Station prompted the NRC to shift considerable personnel resources to an emergency task force assigned with ensuring that both existing and proposed U.S. nuclear facilities are adequately protected from similar seismic events. An earthquake that struck Virginia only months later caused additional reassignment of NRC engineering staff members to an assessment of that incident. As a result of these emergent priorities, members of the teams assigned to review licensing applications for new nuclear projects were tasked with other assignments, delaying technical reviews of new nuclear licensing applications. The PTN 6 & 7 Project is not alone in having been affected by those staffing challenges. Exelon, Tennessee Valley Authority, PSEG, and other projects have also received revised review schedules.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit overturned the NRC's 2010 update to its waste confidence rule. That update determined that spent fuel could be safely stored at power plants for 60 years beyond their operation. According to the Court, the NRC issued a flawed decision as it had not conducted sufficient environmental studies before approving the revisions. In response to the Court's decision, the NRC issued an order on August 7, 2012 stating it would wait before approving licenses for new nuclear plants or renewing licenses of existing facilities until the issue of how to store radioactive waste is resolved. Though no final decisions will be made regarding approvals, the underlying process for licensing new and existing plants continue to progress.

In September 2013, the NRC completed the draft generic environmental impact statement ("GEIS") in support of the proposed waste confidence rulemaking and submitted it to the EPA. It released the draft to the public for a comment period intended to last 75 days. However, the federal government shutdown in October 2013 forced the NRC to furlough 3,600 of its 3,900 employees. While essential personnel remained available for safety inspections and emergencies, the NRC suspended all nonemergency reactor-licensing, including postponing several public meetings concerning the draft GEIS. The comment period was subsequently extended from its initial close date of November 27, 2013 to December 20, 2013. The NRC currently expects to deliver the final GEIS and rule by October 2014.

Q. Please describe what decisions related to PTN 6 & 7 were made in 2013.

A. Key decisions made in 2013 involved the state and federal licensing efforts. In order to support the geotechnical documentation of features of the PTN 6 & 7 in responses to the NRC's RAIs, FPL engaged Rizzo and Associates ("Rizzo"), a highly-respected geotechnical engineering firm. FPL engaged Rizzo because of the vendor's significant contributions to the geotechnical analyses that have been conducted at other new nuclear development sites.

On the state level, FPL made a number of key decisions regarding stipulation agreements with stakeholders in the SCA process. By working closely with other parties, FPL was able to reach agreements that limited the scope of the SCA hearings, preventing an even more protracted schedule.

As it has in years past, FPL determined in 2013 that continuing to extend PTN 6 & 7's reservation agreement with Westinghouse for reactor vessel head ultra-heavy forgings presented the best value to customers. Constraints with regard to ultra-heavy forgings have loosened considerably in recent years, and FPL has continued to maintain flexibility with regard to the agreement by regularly extending the terms while the Company evaluates the risks and benefits of maintaining the reservation.

Lastly, due to ongoing uncertainty with the timing of the NRC's license review process for PTN 6 & 7, FPL has made plans to reevaluate its execution schedule for the units after the NRC publishes a new review schedule.

Q. Was PTN 6 & 7 deemed feasible by the Company during the period of your review?

A. Yes. In the second fiscal quarter of 2013, the Company performed a feasibility analysis regarding PTN 6 & 7, concluding that the project continued to be feasible in five of the seven scenarios of fuel and environmental compliance costs considered. FPL revisits its feasibility analysis on an annual basis in accordance with NCRC requirements.

Project Estimating and Budgeting Processes

Q. Please describe how the project budgets were developed for PTN 6 & 7 in 2013.

A. As in prior years, the PTN 6 & 7 budgets were developed based on feedback from each department supporting the New Nuclear Project. Those budgets included a bottom-up analysis that assessed the resource needs of each department during the year. A 15% contingency adjustment was applied to each request for undefined scope or project uncertainties that could not be predicted at the beginning of the year.

Q. Was the process used by PTN 6 & 7 to develop its budgets consistent with the Company's policies and procedures?

A. Yes, the process utilized by PTN 6 & 7 to develop its 2013 budgets was consistent with FPL's corporate procedures, which outline the process to be used by each business unit when developing annual budgets.

No changes were made to the procedures that govern the development of project budgets during 2013.

Q. What mechanisms did the PTN 6 & 7 Project team use to monitor budget performance in 2013?

A. The PTN 6 & 7 Project team used numerous reports to manage budget performance. Those reports are more fully described by FPL Witness Scroggs in Exhibit SDS-4. Throughout the year, on a monthly basis, the PTN 6 & 7 Project Management team received several reports detailing budget variances by department, with explanations of the variances. Those reports included a description of all costs expended in the current month and quarter as well as year-to-date and total cumulative spending. In addition, the PTN 6 & 7 Project team published quarterly "Due Diligence" reports for the Company's senior executives. Further, project management presented a status update to FPL's senior management on a monthly basis. Those presentations included a description and explanation of any budget variances or significant project challenges.

Q. Are those reporting mechanisms consistent with the PTN 6 & 7 Project Execution Plan?

A. Yes. Reporting mechanisms in place throughout 2013 were consistent with the PTN 6 & 7 Project Execution Plan, which was last revised in March 2010.

Q. Within the PTN 6 & 7 Project team, who was responsible for tracking and reporting project expenditures?

A. Responsibility for tracking and reporting project expenditures was held by the PTN 6 & 7 Project Controls Manager, who worked with a Senior Financial Analyst to review and approve significant vendor invoices, and to track the project's expenditures relative to PTN 6 & 7's annual budget. The processes in place for approving invoices and tracking project expenditures are contained in formal procedures used by the PTN 6 & 7 Project team. These procedures are reviewed regularly, and are updated as changes become necessary.

Q. Did Concentric have observations related to the PTN 6 & 7 budget processes?

A. Concentric found that in 2013 the PTN 6 & 7 Project team acted prudently when developing its annual budget and in tracking its performance relative to the annual budget. As in years past, the PTN 6 & 7 Project team developed a series of reports that track budget performance on a cumulative and periodic basis, along with a process for describing variances in actual expenditures relative to the budget. The PTN 6 & 7 budget processes continue to include a variety of mechanisms that ensure that the project's management and the Company's senior management are well informed of the project's performance.

Q. What are your observations regarding the Company's Quarterly Risk Assessments?

A. The Quarterly Risk Assessments, which contain an assessment of key issues in six areas (*i.e.*, NRC License, Army Corps of Engineers Section 404b and Section 10 Permits, State Site Certification, Underground Injection Control Permit, Miami Dade County Zoning and Land Use, and Development Agreements), along with FPL's mitigation strategy, continue to be important tools to assist the Company in analyzing, monitoring, and mitigating risks. The Quarterly Risk Assessments also provide the Company with another method of tracking trends in key issues facing the project, as well as the potential impacts to implementation, cost, and schedule.

The Quarterly Risk Assessments are one of the methods by which FPL's senior leadership is apprised of the PTN 6 & 7 Project's status. The assessments are, therefore, very important to clearly communicate all risks and the full suite of mitigation strategies being considered for the project.

Q. Has FPL developed a cost estimate that is sufficiently detailed for the current phase of the project?

A. Yes. FPL's cost estimate is currently indicative in nature and will need to be much more definitive before FPL commits to the construction phase of the project. The Company plans to obtain a more definitive cost estimate as the project progresses beyond the licensing phase.

Q. Did FPL review its overnight cost estimate for the PTN 6 & 7 Project?

A. Yes. FPL regularly evaluates whether design changes incorporated by Westinghouse in response to the Fukushima incident or for other reasons are likely to materially affect FPL's cost estimate for PTN 6 & 7.

After conducting a review of cost trends among other AP1000 projects, FPL determined that no change in its cost estimate is warranted at this time. Concentric understands that the Company plans to continue monitoring cost trends among the other utilities pursuing new nuclear units, and FPL will work with them and its contractors to update cost estimates in the future, as appropriate.

Project Schedule Development and Management Processes

Q. Please describe how the PTN 6 & 7 Project team produced and managed the PTN 6 & 7 schedule in 2013.

A. The initial PTN 6 & 7 Project schedule was developed earlier in PTN 6 & 7's life cycle. This schedule continues to be refined and managed using an industry standard software package developed by Primavera Systems, Inc., which I described in the context of the EPU Project's schedule development.

As I discussed above, state and federal review schedules continue to evolve. When a revised schedule from the NRC becomes available, FPL will evaluate the effect that any schedule adjustments may have on the project timeline, including the assessment of whether early construction phases can be further condensed to capture lost time from extended regulatory reviews.

The PTN 6 & 7 project schedule is currently managed by the New Nuclear Projects and Project Development organization leaders. If and when the project moves beyond the licensing phase, responsibility for the PTN 6 & 7 schedule will transition to the Project Controls organization.

Q. What procedures or project instructions existed in 2013 to govern the development and refinement of the PTN 6 & 7 schedule?

A. New Nuclear Project - Project Instruction 100 continues to govern the development, refinement and configuration of the project schedule. No substantive changes were made to this project instruction in 2013, although the Company expects to revisit this document in 2014.

Q. What mechanisms were in place to ensure that the PTN 6 & 7 Project team prudently managed its schedule performance?

A. The PTN 6 & 7 Project team proactively monitored and managed its schedule performance on a weekly and monthly basis. In addition, the PTN 6 & 7 Project team has incorporated similar reporting requirements into its contracts with key vendors, such as Bechtel, requiring them to submit monthly progress reports detailing their progress to date, including any projected delays.

Q. Did Concentric have any observations related to how the PTN 6 & 7 Project team managed and reported its schedule performance in 2013?

A. Yes. Concentric believes PTN 6 & 7 has taken appropriate steps to prudently manage and report on its schedule performance, which include keeping executive management informed on the project's progress against its schedule plans.

Contract Management and Administration Processes

Q. Did PTN 6 & 7 require the use of outside vendors in 2013?

A. Yes. In order to avoid the need to recruit, train and retain the significant number of employees required to obtain a COL and Site Certification, to complete other project activities, and to respond to interrogatories from federal, state, and local agencies, FPL continued to use a number of outside vendors in 2013. Those vendors were utilized to provide ongoing post-submittal support, among other tasks. As has been the case in years past, FPL's use of outside vendors and contractors is consistent with standard practices in the new nuclear industry.

Q. How did the PTN 6 & 7 Project team make certain that it was prudently managing and administering its procurement processes?

A. FPL has a number of corporate procedures related to the procurement function. In addition, ISC, which has overall responsibility for managing FPL's commercial interactions with vendors, produced a desktop Procurement Process Manual that provides more detailed instructions for implementing the corporate procedures, while also containing nuclear-specific procurement procedures. The corporate procedures, along with the Procurement Process Manual, are sufficiently detailed to ensure that ISC prudently manages the procurement activities that must take place to support an endeavor such as PTN 6 & 7. Additionally, those procedures clearly state a preference for competitive bidding except in instances where no other supplier can be identified, in cases of emergencies, or when a compelling business reason not to seek competitive bids exists.

Q. Were any procedures used by the ISC team revised in 2013?

A. In 2013, no changes were made to procedures governing contractor oversight and management. However, one change was made to procedures related to contractor selection. The instructions outlining the use of pre-determined sources were revised to require approval from an ISC Vice President or a higher level in the project organization.

Q. Did Concentric review examples of how these processes were implemented throughout 2013?

A. Yes. Concentric reviewed information related to new contracts, purchase orders and change orders issued for the PTN 6 & 7 Project that involved at least $100,000. Relative to prior years, PTN 6 & 7 entered into comparatively few new contracts in 2013, executing only four such contracts during the year. Of these, all four were single-sourced.

Q. What processes were in place to ensure that PTN 6 & 7 received the full value for the goods and services that were procured in 2013 and that appropriate charges were invoiced to the project?

A. In order to ensure that the Company and its customers received the full value of the goods and services that were procured, the PTN 6 & 7 project directors and their staffs were responsible for reviewing each invoice received from the major PTN 6 & 7 Project vendors. To perform that review, the Business Manager's staff received the invoices from each of the project's vendors. Upon receipt, an Invoice Review/Verification Form that detailed which technical or functional representative was responsible for reviewing each section of the invoice was attached to the invoice. That form and the respective invoice were then sent to each reviewer to verify that the appropriate charges were included in the invoice and that the work product met PTN 6 & 7's needs and contractual provisions prior to payment. When discrepancies were identified, FPL sought a credit on a future invoice or deducted the amount from the current invoice depending on discussions with the vendor. Similar processes are utilized by the FPL departments that support PTN 6 & 7.

Q. Does Concentric have any observations related to FPL's management of the contract management and administration processes?

A. Yes. Concentric found that FPL managed the contract management and administration process according to its corporate procedures and guidelines in 2013.

Internal Oversight Mechanisms

Q. What internal reporting mechanisms were used to inform the Company's senior management of PTN 6 & 7's status and key decisions?

A. As I discuss above, the PTN 6 & 7 Project team continued to use a number of periodic reports in 2013 to inform the project management team and the Company's executive management of progress with PTN 6 & 7. Those reports are described in greater detail in the direct testimony of FPL Witness Scroggs and are used to make certain that the costs PTN 6 & 7 is incurring are the result of prudent decision-making processes. Those reports included monthly reports that detailed key budget and schedule performance.

Q. What other internal oversight and review mechanisms exist for the New Nuclear Project?

A. PTN 6 & 7 is subject to FPL's corporate procedures, but prior to March 2013 had been developed outside of the FPL Nuclear Division. Therefore, PTN 6 & 7 had not been automatically subject to the Nuclear Division's policies. To address this condition, and to remain in compliance with the NRC's QA requirements, the FPL QA/QC department developed a procedure, QI-2-NNP-01, that identifies which FPL Nuclear Division polices are applicable to PTN 6 & 7. QA/QC staff created a regular update schedule to revise and update this procedure in order to adapt to the dynamic nature of the project. As of March 2013 PTN 6 & 7 became a part of the Nuclear Division, and continued to follow the applicable policies identified by Procedure QI-2-NNP-01.

Additionally, there were two active internal oversight and review mechanisms for PTN 6 & 7: the FPL Internal Audit Department and the FPL QA/QC department.

Q. Please describe the FPL Internal Audit Department and its function.

A. FPL's Internal Audit Department, described earlier in the context of the EPU project, performs regular audits of PTN 6 & 7, not only focusing on the eligibility of the costs being recorded to the NCRC for recovery from customers, but also considering internal controls as part of its procedures, and commenting to PTN 6 & 7 if it finds areas for improvement. Each year, the FPL Internal Audit Department performs an audit of PTN 6 & 7 to test whether charges billed to the project are appropriate and that those charges are being accounted for correctly. Very often, findings are resolved during the course of the audit, and any unresolved items are tracked within a database to make sure they are completed on schedule.

Costs incurred by the New Nuclear Project in 2013 are currently being reviewed by the Company's Internal Audit Department. As of January 2014, a final report was expected to be issued by Internal Audit in April 2014.

Q. Did the Internal Audit Group have any adverse findings related to PTN 6 & 7 in 2013?

A. No, it did not.

Q. Please describe the FPL QA/QC function and its purpose.

A. The FPL QA/QC function has a similar mandate with regard to PTN 6 & 7 as it does for the EPU Project, which was discussed earlier in my testimony.

Q. Were any QA/QC issues found in 2013?

A. The QA/QC function performed several surveillance audits of vendors working on the PTN 6 & 7 project, and produced minor findings in its surveillance of one vendor in July 2013. These concerns were quickly addressed to the satisfaction of the QA/QC team.

Q. Does the Company maintain other internal oversight and review mechanisms for PTN 6 & 7?

A. Yes. The Company maintains other internal oversight mechanisms that are available to help ensure that PTN 6 & 7 is prudently incurring costs. The first of those mechanisms is the FPL Corporate Risk Committee. This committee consists of FPL director-level and other senior employees, and is charged with ensuring that the project appropriately considers risks when making key project decisions. That committee is available to the project when necessary as an additional oversight tool.

Q. Did Concentric have any observations related to PTN 6 & 7's internal oversight mechanisms?

A. Yes. Concentric has found that FPL's internal oversight mechanisms were prudently and appropriately applied in 2013.

External Oversight Mechanisms

Q. What external review mechanisms were used by the PTN 6 & 7 Project team in 2013 to ensure the Company is prudently incurring costs?

A. PTN 6 & 7 and FPL have been subject to several external reviews. These reviews are utilized to make certain industry best practices are incorporated into

PTN 6 & 7 and to improve overall project and senior management performance. These reviews include Concentric's review of the Company's activities and project controls and the FPSC Staff's financial and internal controls audits. Those reviews are in addition to NextEra Energy's company-wide audit of its financial and internal controls, discussed earlier.

Q. Are there other external information sources relied upon by the PTN 6 & 7 Project team?

A. Yes. In 2013, FPL maintained membership in several industry groups that relate to the development of new nuclear projects. Those groups include APOG (the AP1000 owners group), the Electric Power Research Institute, and NEI, among others. Each of those groups provides the PTN 6 & 7 Project team with access to a breadth and depth of information that can be used to enhance the PTN 6 & 7 Project team's effectiveness.

Q. Did Concentric have any observations related to the external oversight mechanisms utilized by FPL in 2013?

A. Based on Concentric's review to date, Concentric believes the PTN 6 & 7 Project team is proactively seeking to incorporate best practices into the management of PTN 6 & 7. That is being achieved by retaining outside experts to review and comment on certain aspects of the project and by soliciting external information sources that can provide useful guidance to the project team.

Section VII: Conclusions

Q. Please summarize your conclusions.

A. It is my conclusion that FPL's decision making and management actions as they related to the costs for which FPL is seeking recovery for the EPU Project and PTN 6 & 7 in 2013 were prudent, and it is thus my opinion that FPL's 2013 expenditures on the EPU Project and PTN 6 & 7 were prudently incurred. FPL's decision making and management actions as they related to the EPU Project in 2013 included: management of the final implementation outage at PTN Unit 4, incorporation of lessons learned from earlier outages into the implementation of the final outage, execution of closeout activities at PSL and PTN, incorporation of lessons learned from NextEra's nuclear fleet into the closeout phase, demobilization of vendors, and de-staffing of the EPU Project organization. For PTN 6 & 7, FPL continued its methodical approach to achieving its licensing goals, which will allow it to continue to create the option to build new nuclear capacity for the benefit of its customers. As a consequence, it is my opinion that FPL's 2013 expenditures on the EPU Project and PTN 6 & 7 were prudently incurred.

It is important to note that for over three decades nuclear power has provided a number of substantial benefits to utility customers in Florida. Those benefits include electric generation with virtually no GHG emissions, fuel cost savings, fuel diversity, reduced exposure to fuel price volatility and efficient land use. As a result, it is prudent for FPL to develop additional nuclear capacity for its customers. FPL has carefully managed the EPU Project, and the Company continues to develop PTN 6 & 7 through capable project managers and directors that are guided by detailed company procedures and appropriate management oversight.

Q. Does this conclude your testimony?

A. Yes, it does.

Endnotes:

[1] U.S. Department of Energy, The Energy Information Administration (EIA), Monthly Nuclear Utility Generation (MWh) by State and Reactor, 2012 Final Release.

Environmental Protection Agency, eGRIDweb online application. http://cfpub.epa.gov/egridweb/view.cfm

[2] "Review of the 2013 Ten-Year Site Plans for Florida's Electric Utilities," *Florida Public Service Commission*, October 2013.

[3] Bloomberg Finance, L.P.

[4] Sears, Keoki S., Glenn A. Sears, and Richard H. Clough, Construction Project Management: A Practical Guide to Field Construction Management. 5th Edition, John Wiley & Sons, Hoboken, NJ, 2008, at 20.

[5] Concentric understands that a few closeout activities remain for completion in 2014 but these activities were transferred from the EPU organization to the appropriate plant organization.

[6] Florida Public Service Commission Order No. PSC-090783-FOF-EI.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost) Recovery Clause)	DOCKET NO. 140009-EI FILED: July 1, 2014

ERRATA SHEET

MARCH 3, 2014 TESTIMONY OF JENNIFER GRANT-KEENE

PAGE #	LINE #	
Page 4	Line 16	Change "$3,366,682" to "$3,396,955"
Page 4	Line 18	Change "$137,415,613" to "$137,385,340"
Page 9	Line 11	Change "$2,903,032" to "$2,933,305"
Page 9	Line 12	Change "$327,823" to "$328,873"
Page 9	Line 13	Change "$987,864" to "$987,873"
Page 9	Line 14	Change "$3,563,073" to "$3,592,305"
Page 10	Line 13	Change "$19,867,885" to "$19,866,836"
Page 10	Line 17	Change "$327,823" to "$328,873"
Page 10	Line 22	Change "$10,872,736" to "$10,872,745"
Page 10	Line 22	Change "$10,599,758" to "$10,599,767"
Page 11	Line 6	Change "$987,864" to "$987,873"
Page 12	Line 9	Change "$72,810,925" to "$72,811,949"
Page 12	Line 12	Change "$3,053,992" to "$3,052,968"
Page 13	Line 2	Change "$72,810,925" to "$72,811,949"
Page 13	Line 2	Change "$3,053,992" to "$3,052,968"
Page 13	Line 6	Change "$14,171,510" to "$14,172,534"
Page 14	Line 19	Change "$100,424,526" to "$100,423,984"
Page 14	Line 19	Change "$14,171,510" to "$14,172,534"
Page 14	Line 21	Change "$345,665" to "$346,689"
Page 15	Line 3	Change "$1,091,984" to "$1,061,727"
Page 15	Line 7	Change "$509,080" to "$539,338"

MARCH 3, 2014 EXHIBITS OF JENNIFER GRANT-KEENE

EXHIBIT #	PAGE #	LINE #	
JGK-1	Page 1	Line 16, Column (B)	Change "$19,889,321" to "$19,888,093"
JGK-1	Page 1	Line 17, Column (B)	Change "($21,436)" to "($21,257)"
JGK-1	Page 1	Line 21, Column (B)	Change "$10,599,758" to "$10,599,767"
JGK-1	Page 1	Line 22, Column (B)	Change "$72,810,925" to "72,811,949"
JGK-1	Page 1	Line 23, Column (B)	Change "$1,091,984" to "$1,061,727"
JGK-1	Page 1	Line 25, Column (B)	Change "$104,370,552" to "$104,340,279"
JGK-1	Page 1	Line 27, Column (B)	Change "$137,415,613" to "$137,385,340"

Note that these corrections affect other lines/columns (i.e., subtotals and totals) of this exhibit. The result of these corrections is a $30,273 decrease in the Total TP 6 & 7 and Uprate Project in (Over)/Under Recovery amount.

EXHIBIT #	PAGE #	LINE #	
JGK-3	Page 1	Line 41(Jan-Dec)	Change "$1,180,959" to "$1,181,045"
JGK-3	Page 1	Line 41(Total)	Change "$14,171,510" to "$14,172,534"

Note that these corrections affect other lines/columns (i.e., subtotals and totals) on this exhibit. The result of this correction is a $1,025 increase in Total Base Rate Revenue Requirements including Post In Service Costs and Adjustments.

EXHIBIT #	PAGE #	LINE #	
JGK-2	Page 1	Line 95	Delete footnote (a)

EXHIBIT #	PAGE #	LINE #	
JGK-5	Page 1	Line 7, Column (M)	Change "$345,072" to "$344,869"
JGK-5	Page 1	Line 9, Column (M)	Change "$577,972" to "$577,632"
JGK-5	Page 1	Line 30, Column (M)	Change "$1,882,126,106" to "$1,882,125,564"
JGK-5	Page 1	Line 7, Column (N)	Change "$11,095" to "$10,893"
JGK-5	Page 1	Line 9, Column (N)	Change "$2,544" to "$2,204"
JGK-5	Page 1	Line 30, Column (N)	Change "$100,424,526" to "$100,423,984"

EXHIBIT #	PAGE #	LINE #	
JGK-6	Page 1	Line 8, Column (G)	Change "($367,860)" to "($525,209)"
JGK-6	Page 1	Line 26, Column (G)	Change "($631,621)" to "($768,715)"
JGK-6	Page 1	Line 34, Column (G)	Change "($63,278)" to "($61,718)"

Note that these corrections affect other lines/columns (i.e., subtotals and totals) on this exhibit. The result of these corrections is a $292,883 decrease to Total NBV Net of Removal Costs & Salvage.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JENNIFER GRANT-KEENE

DOCKET NO. 140009-EI

March 3, 2014

Q. Please state your name and business address.

A. My name is Jennifer Grant-Keene. My business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

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

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

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

Q. Please describe your educational background and professional experience.

I graduated from Concordia University, Montreal, Canada with a Bachelor of Arts in 1978 and Rutgers University, New Jersey in 1984 with a Masters of Business Administration degree, with a Concentration in Accounting. That same year, I was employed by Peat Marwick Mitchell & Company, in Short Hills, New Jersey. Between 1990 and 2000, I lectured in the Accounting Departments of North Carolina Central University, Durham, North Carolina and Lynn University, Boca Raton, Florida. Since 2001 and prior to joining FPL, I have held various Corporate Accounting positions in the state of Florida. In 2009, I joined FPL as an Accounting Manager responsible for Fossil and Nuclear Fuel Accounting, Storm Accounting and Reporting and Analysis for the Property Accounting Group. In January 2014, I assumed the role of New Nuclear Accounting Project Manager. I am a Certified Public Accountant (CPA) licensed in the State of New Jersey and a member of the American Institute of CPAs.

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

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

- Exhibit JGK-1, Final True-Up of 2013 Revenue Requirements, details the components of the 2013 TP 6 & 7 and EPU revenue requirements reflected in the NFR True-Up (T) Schedules by project, by year and by category of costs being recovered.
- Exhibit JGK-2, Turkey Point 6 & 7 2013 Site Selection and Pre-construction Costs and Uprate 2013 Construction Costs, details the total company costs and jurisdictional costs by project and by cost category.
- Exhibit JGK-3, 2013 Base Rate Revenue Requirements, details the 2013 Actual revenue requirements for the Uprate Project plant modifications placed into service.

- Exhibit JGK-4, 2013 Incremental Labor Guidelines, flowcharts the process used to determine incremental payroll costs chargeable to the TP 6 & 7 and EPU projects for 2013.
- Exhibit JGK-5, St. Lucie and Turkey Point Uprate Project 13 Month Average of Incremental 2012 Plant Placed into Service, shows the incremental Actual 2012 plant placed into service including 2013 costs.
- Exhibit JGK-6, St. Lucie and Turkey Point Uprate Project Actual Net Book Value of Retirements, Removal Cost and Salvage for Plant Placed into Service in 2012, shows the calculation of the difference between FPL's 2012 Actual Net Book Value of Retirements, Removal Cost and Salvage updated for 2013 post in service costs and the amount recovered in base rates in 2013, as filed in Docket No 120244-EI.

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

- Exhibit SDS-1, T-Schedules 2013 Turkey Point 6 & 7 Site Selection and Pre-construction Costs, consists of the 2013 TP 6 & 7 Site Selection NFR Schedules T-1 and T-3A and the 2013 TP 6 & 7 Pre-construction NFR Schedules T-1 through T-7B. SDS-1 contains a table of contents which lists the T-Schedules sponsored and co-sponsored by FPL Witness Scroggs and by me, respectively.
- Exhibit TOJ-1, 2013 EPU T-Schedules and TOR-Schedules, consist of 2013 T-Schedules and applicable True-Up to Original (TOR) Schedules, now that the project is complete. The 2013 T-Schedules, consist of the 2013 Uprate Project T-Schedules T-1 through T-7B. The TOR-Schedules consist of TOR-6, TOR-6A, and

TOR-7. The NFR Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Jones and by me, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the final true-up calculation of the 2013 revenue requirements. I provide an overview of the components of the revenue requirements included in FPL's filing and demonstrate that the filing complies with FPSC Rule No. 25-6.0423, Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery (Nuclear Cost Recovery or NCR) Rule. I also explain how carrying costs are provided for under the NCR Rule, describe the base rate revenue requirements included for recovery in the NFR Schedules, and discuss the accounting controls FPL relies upon to ensure only appropriate costs are charged to the TP 6 & 7 and EPU projects.

Q. Please summarize your testimony.

A. FPL is requesting the Florida Public Service Commission (FPSC or Commission) approve as prudent its 2013 costs and the resulting overrecovery of revenue requirements of $3,366,682 which will reduce the CCRC charge to customers in 2015. As shown in my Exhibit JGK-1, these revenue requirements are comprised of the difference between $137,415,613 Actual revenue requirements versus $140,782,295 Actual/Estimated revenue requirements. My testimony includes the exhibits and NFR Schedules needed to support the true-up of the 2013 Actual costs and revenue requirements.

FPL is complying with the NCR Rule and has in place robust and comprehensive corporate and overlapping business unit controls for incurring and validating costs and recording transactions associated with FPL's TP 6 & 7 and EPU projects. I describe these controls and outline the documentation, assessment and auditing process for these overlapping control activities.

NUCLEAR COST RECOVERY RULE

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

A. The Nuclear Cost Recovery Rule applies to FPL's TP 6 & 7 and EPU projects. In compliance with the NCR Rule, FPL is recovering the costs and carrying costs for TP 6 & 7 on an annual basis as the work is being performed for the licensing and permitting activites described by FPL Witness Scroggs. Only the carrying charges on the construction balance, recoverable O&M, and the base rate revenue requirements for the year plant is placed into service is recovered for the EPU Project.

FPL does not recover its capital investment until systems or components are placed into service, and even then, such base rate recovery does not reimburse FPL immediately. Rather, the substantial sums FPL expended during construction to purchase equipment, pay vendors, etc., will be recovered over the lives of the operating units.

The NFR Schedules provide an overview of nuclear power plant projects and a roadmap to the detailed project costs. The NFR Schedules consist of T-Schedules, Actual/Estimated (AE) Schedules, Projected (P) Schedules, and TOR-Schedules. The T-Schedules provide the final true-up for the prior year.

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

A. FPL is filing for the TP 6 & 7 and EPU projects the 2013 T-Schedules, consistent with the requirements of the NCR Rule, to provide an overview of the financial and construction aspects of its nuclear power plant projects, outline the categories of costs represented, and provide the calculation of detailed project revenue requirements. FPL completed the EPU Project in 2013; therefore FPL is also filing for the EPU Project the following final TOR-Schedules: TOR-6, TOR-6A, and TOR-7. These TOR-Schedules follow the format of the T-Schedules, but also detail the actual to date project cost as follows:

- TOR-6 – Provides the Actual expenditures through 2013 by major tasks performed for the EPU Project.
- TOR-6A – Provides a description of the major tasks performed by construction category for the year filed.
- TOR-7 – Reflects initial project milestones in term of costs, budget levels, initiation dates, and completion dates as well as all revised milestones and reasons for each revision.

TP 6 & 7 2013 TRUE-UP

Site Selection

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

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

Q. What are FPL's 2013 Actual TP 6 & 7 Site Selection costs compared to the previous Actual/Estimated costs?

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

Q. What are FPL's 2013 TP 6 & 7 Site Selection Actual carrying charges compared to the previous Actual/Estimated carrying charges and any resulting over/underrecovery?

A. The calculation of FPL's 2013 Actual TP 6 & 7 Site Selection carrying charges on the deferred tax asset are $170,485 as shown in Exhibit SDS-1, NFR Schedule T-3A. FPL's previous Actual/Estimated carrying costs on the deferred tax asset were $170,485. The deferred tax asset is created by the recovery of Site Selection costs and the payment of income taxes before a deduction for the costs is allowed for income tax purposes. Since FPL no longer incurs Site Selection costs other than the return on the deferred tax asset, there is no true-up of 2013 costs needed.

Pre-construction

Q. Is FPL filing any NFR Schedules related to 2013 TP 6 & 7 Pre-construction costs?

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

Q. What revenue requirement amount is FPL requesting to reflect the final true-up of its 2013 TP 6 & 7 Pre-construction costs?

A. FPL is requesting to include in its 2015 Capacity Cost Recovery Clause (CCRC) charge an overrecovery of $463,650 in revenue requirements, which represents an overrecovery of Pre-construction costs of $539,308, and an underrecovery of carrying charges of $75,659 as shown on Exhibit JGK-1 and in the calculations in Exhibit SDS-1, NFR Schedules T-2 and T-3A. The overrecovery of $463,650 will reduce the CCRC charge paid by customers when the CCRC is reset for 2015.

Q. What are FPL's 2013 actual TP 6 & 7 Pre-construction costs compared to 2013 Actual/Estimated costs and any resulting over/underrecoveries?

A. FPL's actual TP 6 & 7 Pre-construction costs for the period January through December 2013 are $28,728,488, ($28,209,654 on a jurisdictional basis, net of participants) as presented in FPL Witness Scroggs's testimony and provided on SDS-1, NFR Schedule T-6. FPL's Actual/Estimated 2013 Pre-construction costs were $29,277,715 ($28,748,963 on a jurisdictional basis, net of participants). The result is an overrecovery of Pre-construction revenue requirements of $539,308.

Q. What are FPL's 2013 actual TP 6 & 7 Pre-construction carrying charges compared to 2013 Actual/Estimated carrying charges and any resulting over/underrecoveries?

A. FPL's 2013 Actual TP 6 & 7 Pre-construction carrying charges are $4,664,921. FPL's previous Actual/Estimated carrying charges were $4,589,263, resulting in an underrecovery of revenue requirements of $75,659. The calculations of the carrying charges can be found in Exhibit SDS-1, NFR Schedules T-2 and T-3A.

EPU PROJECT 2013 TRUE-UP

Q. Is FPL filing any NFR Schedules related to its 2013 EPU Project costs?

A. Yes, FPL is filing NFR Schedules T-1 through T-7B as described in FPL Witness Jones's testimony for the final true-up of 2013 EPU Project costs as shown in Exhibit TOJ-1, as well as the TOR-Schedules summarized above.

Q. What revenue requirement amount is FPL requesting to reflect the final true-up of its 2013 EPU Project costs?

A. FPL is requesting to include an overrecovery of $2,903,032 in revenue requirements, which represents an overrecovery of carrying costs of $327,823, an underrecovery of O&M and interest costs of $987,864, and an overrecovery of base rate revenue requirements and carrying costs of $3,563,073, as shown on Exhibit JGK-1.

Q. What are FPL's 2013 Actual EPU Project construction costs used as the basis for the calculation of carrying charges?

A. FPL's actual 2013 EPU Project Generation and Transmission construction costs, for the calculation of carrying costs, are $146,821,183, (total company) as shown on my Exhibit JGK-2. These construction expenditures are also presented in FPL Witness Jones's testimony and shown on Exhibit TOJ-1, NFR Schedule T-6. The portion of this total for which the St. Lucie Unit 2 participants are responsible is deducted from actual construction costs and the retail jurisdictional separation factor is applied to the remainder. This results in jurisdictional, net of participants, EPU Project Generation and Transmission construction costs of $144,081,119.

For the calculation of actual carrying charges, further adjustments are made to present the construction costs on a cash basis (i.e., excluding accruals and pension and welfare benefit credits) and results in the construction costs of $175,307,949 as shown on Exhibit TOJ-1, NFR Schedule T-3 for the calculation of carrying charges. These adjustments are necessary in order to comply with the Commission's practice regarding Allowance for Funds Used During Construction (AFUDC) accruals.

Q. What are FPL's EPU Project 2013 Actual carrying charges compared to the previous Actual/Estimated carrying charges?

A. The EPU Project actual carrying charges on construction expenditures and on the deferred tax liability are $19,867,885, as shown in my Exhibit JGK-1 and detailed in NFR Schedules T-3 and T-3A in Exhibit TOJ-1. FPL's previous Actual/Estimated 2013 EPU Project carrying charges were $20,195,708 as filed in Docket No. 130009-EI. As a result of the final true-up of 2013 carrying charges in this filing, there is an overrecovery of $327,823 in 2014. Carrying charges on base rate revenue requirements are discussed later in my testimony.

Q. What are FPL's EPU Project 2013 Actual recoverable O&M costs compared to its previous Actual/Estimated O&M costs?

A. FPL's EPU Project 2013 actual recoverable O&M costs including interest are $10,872,736 ($10,599,758 jurisdictional, net of participants), the calculation of which can be found in Exhibit TOJ-1, NFR Schedule T-4. FPL's previous Actual/Estimated

2013 EPU Project recoverable O&M including interest was $9,790,510 ($9,611,895 jurisdictional, net of participants). As shown in NFR Schedule T-4, over/underrecoveries of recoverable O&M accrue interest at the AA Financial 30-day rate posted on the Federal Reserve website. As a result of the final true-up of 2013 EPU Project recoverable O&M including interest, there is an underrecovery of $987,864 jurisdictional, net of participants in 2014.

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

A. As described in Order No. PSC-08-0749-FOF-EI in Docket No. 080009-EI, FPL "shall be allowed to recover through the NCRC associated revenue requirements for a phase or portion of a system placed into commercial service during a projected recovery period. The revenue requirement shall be removed from the Nuclear Cost Recovery Clause (NCRC) at the end of the period. Any difference in recoverable costs due to timing (projected versus actual placement in service) shall be reconciled through the true-up provision."

In accordance with FPL accounting policies, effective in the month each transfer to Plant In-Service was made, FPL transferred the related costs from Construction Work in Progress (CWIP) to Plant In-Service. For plant placed into service less than $10 million, carrying charges were calculated for half a month and base rate revenue requirements were calculated for half a month. For plant placed into service greater than $10 million, carrying charges and base rate revenue requirements were calculated to the day the plant was placed into service. Subsequent to the month the plant was placed into service, carrying charges ceased and the 2013 base rate revenue requirements related to the plant placed into service was included for recovery through the NCRC. Included in the base rate revenue requirement is any non-incremental labor related to the EPU Project. FPL's 2013 actual transfers to Plant In-Service, including non-incremental labor, are shown in Exhibit JGK-3, with details in Exhibit TOJ-1, Appendix B.

Q. What is the total of 2013 base rate revenue requirements and related plant placed into service?

A. EPU Project actual base rate revenue requirements for plant placed into service in 2013 is $72,810,925 as shown in Exhibit JGK-1, JGK-3 and calculation details in Exhibit TOJ-1, Appendix B. FPL's previous Actual/Estimated 2013 base rate revenue requirements were $75,864,917. As a result of the true-up of actual 2013 EPU Project base rate revenue requirements there is an overrecovery of $3,053,992 as shown on my Exhibit JGK-1. The actual transfers to Plant In-Service related to these revenue requirements were $759,365,907 ($744,236,151 jurisdictional, net of participants) as shown in Exhibit TOJ-1, Appendix B. The carrying charges on the over/underrecoveries of the base rate revenue requirements compared to prior Actual/Estimated over/underrecoveries are shown in Exhibit TOJ-1, Appendix C.

The rate of return used to calculate the base rate revenue requirements is the rate of return in the most current monthly earnings surveillance reports filed with the Commission at the time the EPU Project modifications are placed into service. This is in accordance with the requirements of the Nuclear Cost Recovery Rule No. 25-6.0423 Section 8(d).

Q. What are the major components of FPL's actual base rate revenue requirements of $72,810,925 in 2013 and overrecovery of $3,053,992 for the EPU Project as shown in Exhibit JGK-1?

A. The 2013 base rate revenue requirements include revenue requirements on 2013 Plant In-Service in the amount of $57,311,467 and the 2013 Post in Service Costs related to 2012 Incremental Plant In-Service of $14,171,510.

Q. Please explain the revenue requirements associated with the 2013 Plant In-Service.

A. FPL's actual transfers to Plant In-Service in 2013 totaled $701,354,489 ($688,496,674 jurisdictional, net of participants) and results in $57,311,467 in revenue requirements as shown on TOJ-1, Appendix B and in JGK-3. The Actual/Estimated transfers to Plant In-Service were $724,180,413 ($710,917,362 jurisdictional, net of participants) and resulted in $59,743,716 in revenue requirements as shown in Appendix B in Docket No. 130009-EI. The true-up of 2013 plant placed into service in this filing resulted in an overrecovery of $2,432,249 on revenue requirements. Appendix B provides the details of the plant placed into service.

Q. Please explain the 2013 revenue requirements associated with the 2013 Post in Service Costs Related to 2012 Incremental Plant In-Service.

A. FPL included in its 2012 true-up filed in March 2013 in Docket No. 130009-EI, Actual costs of $1,999,281,325 for 2012 plant placed into service as shown in my Exhibit JGK-5, Column E. In FPL's Actual/Estimated filing in Docket No. 130009-EI, Actual/Estimated 2013 post in service costs of $20,514,671 ($18,334,654 jurisdictional, net of participants) related to 2012 Plant In-Service were included, and resulted in total 2012 plant placed in service of $2,019,795,996 as shown on Exhibit WP-7 filed in Docket No. 130009-EI. FPL then compared the total Actual/Estimated 2012 Plant In-Service (including A/E 2013 Post in Service costs) of $2,019,795,996 to the 2012 Plant In-Service in FPL's 2012 Base Rate Increase of $1,886,772,814, filed October 2012 in Docket No. 120244-EI. The difference of $133,023,182 represented FPL's Actual/Estimated 2012 Incremental Plant In-Service (including A/E 2013 Post in Service costs) and resulted in Actual/Estimated Base Rate Revenue Requirements of $13,825,845 as shown in Appendix B filed in Docket No. 130009-EI.

In this docket, as shown in my Exhibit JGK-5, FPL again utilized the 2012 Plant In-Service of $1,999,281,325 but included $26,479,025 ($24,797,592 jurisdictional, net of participants) of Actual 2013 post in service costs related to 2012 Plant In-Service as well as an adjustment to salvage of $502,521 ($493,487 jurisdictional, net of participants), for a total of 2012 Plant In-Service including 2013 post in service costs of $2,026,262,870. When compared to 2012 Plant In-Service as filed in FPL's 2012 Base Rate Increase, Docket No. 120244-EI, the true-up of 2012 Incremental Plant In-Service (including Actual 2013 post in service costs) is $139,490,056 ($132,263,799 jurisdictional, net of participants). The resulting true-up of Base Rate Revenue Requirements based on a 13-month average rate base of $100,424,526 is $14,171,510 as shown in my Exhibit JGK-5 and Exhibit TOJ-1, Appendix B. This results in an underrecovery of revenue requirements of $345,665 as shown in Exhibit TOJ-1, Appendix B.

Q. What are the carrying charges on the over/underrecovery of base rate revenue requirements?

A. Actual carrying charges of $1,091,984 are shown in my Exhibit JGK-1 and detailed in Exhibit TOJ-1, Appendix C. FPL's previous Actual/Estimated carrying charges were $1,601,064 as filed in its May 2013 filing, Docket No. 130009-EI. As a result of the final true-up of 2013 carrying charges in this filing, there is an overrecovery of $509,080.

Q. How much has FPL included in its 2013 costs for Net Book Value of Retirements, Removal and Salvage?

A. In 2013 FPL recognized Net Book Value (NBV) of Retirements of $26,281,522, Removal Costs of $7,991,242 and Salvage credits of $3,059,556, totaling $31,213,208 as shown in JGK-2.

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

A. Costs that would have been incurred regardless of the EPU Project are not included in FPL's NCRC calculations. Such expenditures that are not "separate and apart" EPU Project expenditures are accounted for under the normal process for O&M and capital expenditures. Capital expenditures accrued AFUDC while in CWIP until the system or component was placed into service. Only costs incurred for activities necessary for the EPU Project are charged to the EPU Project internal orders and included as recoverable O&M or as construction costs used in the calculation of carrying charges in the NFR Schedules. This method ensures that FPL only receives recovery of the appropriate recoverable O&M or carrying charge return under the Nuclear Cost

Recovery Rule. As explained by Witness Jones, FPL employs a rigorous, engineering-based process to segregate costs that are "separate and apart" from those that would have been incurred absent the EPU Project, so that only the appropriate costs are reflected in the NCRC request.

ACCOUNTING CONTROLS

Q. Please describe the accounting controls FPL relied upon to ensure proper cost recording and reporting for these projects in 2013.

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

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

The project controls are discussed in the 2014 testimonies of FPL Witnesses Scroggs and Jones.

Q. Were these controls documented, assessed and audited and/or tested?

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

Q. Describe the responsibilities and accounting controls of the New Nuclear Accounting Project Group in 2013.

A. The primary responsibility of the New Nuclear Accounting Project Group was to provide financial accounting guidance for the recovery of costs under the Nuclear Cost Recovery Rule. Additional responsibilities included the preparation and maintenance of the NFR Schedules and, on a monthly basis, ensuring the costs included in the NFR Schedules are recorded in the financial records of the Company and reconciled to the NFR Schedules. The TP 6 & 7 and EPU projects utilized unique internal orders to capture costs directly related to these projects. After ensuring accurate costs were recorded, adjustments were made to reflect participants' credits, the jurisdictionalized costs, and other adjustments required in the NFR Schedules. Monthly journal entries were prepared to reflect the effects of the recovery of these costs and monthly reconciliations of the project general ledger accounts were performed. The resulting NFR Schedules are included in FPL's Nuclear Cost Recovery filings and described in testimony.

The New Nuclear Accounting Project Group worked closely with the Nuclear Business Unit, Engineering, Construction & Corporate Services Division (ECCS), and the Transmission Business Unit to ensure proper accounting for costs related to the projects.

TP 6 & 7 SPECIFIC ACCOUNTING CONTROLS

Q. Describe the role of ECCS related to TP 6 & 7 in 2013.

A. A Project Controls Group reported through the Vice President of ECCS and provided structural leadership, governance and oversight for the project. On a monthly basis, the group completed a thorough review of costs ensuring accuracy of the charges posted to the project. Additionally, Project Controls prepared monthly variance reports, identifying variances against budgeted information. Team members and project management reviewed monthly budget variances against the projected forecast. The Project Controls Group included a Manager of Cost and Performance with Accounting and Real Estate degrees who had been working in ECCS since 2011. His previous experience includes over seven years with Deloitte & Touché, LLP specializing in energy industry auditing. A Director of Construction with 30 years of experience at FPL and nine years with the Engineering and Construction Department oversaw the Project Controls Group. Staff with business, finance and accounting degrees and nuclear and construction experience supported the Project Controls leadership team.

Q. Describe the ECCS accounting controls which ensured costs were appropriately charged to TP 6 & 7.

A. When a potential goods or services expenditure greater than $10,000 was identified, project personnel routed the relevant information detailing the need, justification, estimated cost and documentation for the request to the Project Controls Group for review. Upon verification of the documentation and availability of budgeted resources, the Project Controls Group electronically advised the requestor of the appropriate internal order and cost element for charging. The requestor then created a "shopping cart" in the Integrated Supply Chain (ISC) module of SAP, attaching the aforementioned documentation including the electronic notification from the Project Controls Group. This information was sent electronically through the shopping cart system to the ISC agent of the functional area who verified the appropriate documentation was attached to the shopping cart. Upon verification, a Purchase Order (PO) was initiated by the ISC agent and forwarded with the attachments to the applicable Director for review to ensure the expenditure was appropriate and relevant to the project. If the Director was in agreement with the expenditure, he electronically approved the PO and a notification was sent to the issuing ISC agent. The ISC agent then electronically issued to the vendor a PO available for charging, copying the original requestor, the Project Controls Group and the approving Director. After the goods were received or services rendered, an invoice was received either by the functional area or by Project Controls, it was reviewed, and if determined to be appropriate, approved based on FPL approval authorization amounts. Approved invoices were then forwarded to the Invoice Processor and upon verification of the approvals and account coding the invoice was entered into the SAP system for processing and payment to the vendor.

Currently, Bechtel Power Corporation is the vendor with the greatest single proportion of costs and is handling the Combined Operating License Application (COLA) and supporting the site certification application. The invoices from this and other vendors, which can be quite voluminous, were received in hard copy or electronically by the Project Controls Group. The invoices were routed to the appropriate business unit contacts to assess, review and approve where appropriate. After the invoice was reviewed by the functional area, the Project Controls Analyst ensured all parties had appropriately approved the invoice prior to payment. The invoices were also reviewed for compliance with the PO and/or contract and differences with vendors were resolved prior to payment. The remaining invoices related to charges incurred by support groups such as Transmission and Environmental Services.

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

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

EPU PROJECT SPECIFIC ACCOUNTING CONTROLS

Nuclear Business Unit Accounting Controls

Q. Describe the oversight role of the Nuclear Business Operations (NBO) Group related to the EPU Project in 2013.

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

Q. Describe the accounting controls which ensured costs were appropriately incurred and tracked for the EPU Project in 2013.

A. The NBO Group accounted for the activities necessary to perform the EPU Project at the four nuclear units, Turkey Point Units 3 and 4 and St. Lucie Units 1 and 2. Costs associated with the work performed on components defined as property retirement units were transferred from CWIP to Plant In-Service at the end of each outage or when they became used and useful. In order to facilitate this process, a separate work breakdown structure was set up for each unit along with capital internal orders to capture costs related to each EPU outage. Additional internal orders were set up, as necessary, to capture costs associated with plant placed into service at times other than during the outages.

Q. Describe the accounting controls which ensured costs were appropriately charged to the EPU Project.

A. Invoices were routed to the St. Lucie or Turkey Point site Project Controls analyst, as appropriate. The analyst checked the invoices for accuracy and for agreement to the PO terms and conditions. Once the invoice had been appropriately verified, the analyst recorded invoice information on an Invoice Tracking Log. The Invoice Approval/Route List was then routed for verification of receipt of goods/services and all required approvals. Before payment could be made on any invoice greater than $1 million, the approval of the Vice President, Nuclear Power Uprate was required. Before payment could be made on any invoice greater than $5 million, the approval of the Executive Vice President & Chief Nuclear Officer or his designee was required. Once all necessary approvals had been obtained, the Project Controls Analyst processed the invoice for payment in NAMS (Nuclear Asset Management System) against the respective PO. Extended Power Uprate Project Instruction Number EPPI-230, *Project Invoice*, detailed the flow of the invoice through the approval, receipt and payment process at the sites and established responsibilities at each stage of the process.

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

A. General ledger detail transactions were monitored by the EPU Project Controls team and NBO to ensure that costs charged to the EPU Project were appropriate and were accurately classified as capital or O&M. Site cost engineers performed reviews to ensure invoices were accurately coded to the appropriate internal order. NBO reviewed internal labor costs to ensure that only appropriate payroll was charged to the EPU Project. In addition, all steps in this process were subject to internal and external audits and reviews.

The Project Engineers and NBO worked together closely to make sure the costs were appropriate and were accurately classified as capital or O&M. Construction Leads performed reviews to ensure invoices were accurately coded to the appropriate internal order.

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

A. The Uprate Project Controls Director, along with the EPU Project Controls team at each site, recorded schedule changes, project delays, and project costs. The Uprate Project Controls Director, along with the EPU Project Controls team, supported risk management and contract administration.

The NBO Group drafted monthly variance reports that compared actual expenditures incurred to the originally estimated budget and reported year end forecast estimates. The draft reports were sent to the St. Lucie and Turkey Point EPU Project Controls team responsible for providing variance explanations and forecast updates to NBO. The reports were reviewed by the EPU Project Controls supervisors and management prior to the submission to NBO. NBO reviewed the variance explanations and forecast numbers for reasonableness and accuracy prior to compilation and inclusion in the Nuclear Business Unit corporate monthly variance report submitted to the

Corporate Budget Group. NBO was also responsible for reviewing numbers reported to the FPL Executive Steering Committee to ensure consistency with corporate variance reports and for providing the Accounting Department with project amounts for inclusion in the NFR Schedules.

Transmission Business Unit Accounting Controls

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

A. The Transmission Business Unit incurred expenditures related to the EPU Project in order to perform substation and transmission line engineering, procurement, and construction on specific internal orders assigned to projects which resulted from transmission interconnection and integration studies performed by FPL Transmission Planning. The Transmission Business Unit Cost and Performance team ensured costs were appropriately incurred and charged to the EPU Project. The Transmission Business Unit reviewed payroll to ensure only appropriate payroll was charged to the EPU Project, determined appropriate accounting for costs, consulted with the Property Accounting Group when necessary, provided accounting guidance and training to the EPU Project team, assisted with internal and external audit-related matters, reviewed project projections, and produced monthly variance reports. Transmission related work for the EPU Project was also accounted for by internal order based on the scope of work and was placed into service when the respective work was used and useful.

Q. Describe the Transmission Business Unit accounting controls which ensured costs were appropriately incurred and tracked for the EPU Project.

A. The Transmission Business Unit identified the transmission activities necessary to support the increased electrical output of the EPU Project. In order to facilitate this process and identify appropriate activities, two separate work breakdown structures were set up with appropriate sub activities and multiple internal orders. Purchase Orders were handled by ISC via the shopping cart process. A shopping cart PO request was routed from the originator to all approvers required based on the dollar amount of the PO. The PO Requisitioning Group determined the required approvals based on the business unit's PO approval limits, and routed the request as required. Once all required approvals were secured, the PO was created.

Q. Describe the Transmission Business Unit accounting controls which ensured costs were appropriately charged to the EPU Project.

A. Invoices were routed to the Transmission Project Controls Administrator (Administrator). The Administrator checked the invoices for accuracy and for agreement to the PO terms and conditions. Once the invoice was appropriately verified, the Administrator recorded invoice information on the Cost Control Tracking sheet and routed the invoice for all required approvals. Invoices found to contain any inaccuracies were returned to the requestor for revisions. Any invoice greater than $1 million required the approval of the Business Unit Vice President. Any invoice greater than $5 million required the approval of the FPL President before payment was made. Once all necessary approvals were obtained, the Administrator processed the invoice for payment in SAP against the respective PO.

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

A. The Cost & Performance Analyst updated the Turkey Point and St. Lucie EPU Project Cost reports on a monthly basis for actual costs incurred. The Turkey Point and St.

Lucie EPU Project Cost reports were then reviewed by the assigned Project Managers and administrators who worked closely together to ensure that all costs were appropriately charged to the EPU Project and were accurately classified as either Capital or O&M. Construction Leaders also performed reviews to ensure all invoices were accurately assigned and coded to the appropriate internal order for the EPU Project. Any discrepancies identified as a result of these reviews were resolved at this time. The assigned Project Manager then updated the individual internal order forecasts, if warranted.

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

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

ADDITIONAL NEW NUCLEAR AND EPU PROJECT ACCOUNTING OVERSIGHT

Q. Were there any additional controls relied upon for these projects and the related reporting in 2013?

A. Yes. The Company had previously issued specific guidelines for charging costs to the project internal orders. These guidelines emphasized the need for particular care in charging only incremental labor to the project internal orders included for Nuclear

Cost Recovery and ensured consistent application of the Company's capitalization policy. These guidelines described the process for the exclusion of non-incremental labor from current NCRC recovery while providing full capitalization of all appropriate labor costs through the implementation of separate project capital internal orders that will be included in future non-NCRC base rate recoveries. Exhibit JGK-4 provides a flowchart depicting this process for 2013.

Q. Did the guidelines for charging costs to the project internal orders change from 2012 to 2013?

A. No. However, as a result of FPL's most recent rate case in Docket No. 120015-EI, the Company reset the basis upon which incremental employee labor is established in determining which employees are clause-recoverable. Therefore, starting in 2013, personnel previously determined non-incremental became incremental.

Q. What is the purpose of the annual internal audits conducted by FPL on the TP 6 & 7 and EPU projects?

A. The Company continues to undergo annual project related internal audits. The objective of these audits is to test the propriety of expenses charged to the NCRC to ensure they are recoverable project expenses and to ensure compliance with the NCR Rule. Any potential process improvements identified during the audits are communicated to management to further enhance internal controls. The audit of the 2013 costs related to the TP 6 & 7 Project is currently underway and is expected to be completed in the second quarter of 2014. The audit of the 2013 costs related to the EPU Project was issued in February 2014 and found that the EPU Project controls were good. These audits provide assurance that the internal controls surrounding transactions and processes are well established, maintained and communicated to employees, and provide additional assurance that the financial and operating information generated within the Company is accurate and reliable.

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause	))	DOCKET NO. 140009-EI FILED: July 1, 2014

ERRATA SHEET

MAY 1, 2014 TESTIMONY OF JENNIFER GRANT-KEENE

PAGE #	LINE #	
Page 1	Line 16	Change “$15,715,991” to “$14,287,862”
Page 2	Line 7	Change “$15,715,991” to “$14,287,862”
Page 2	Line 9	Change “$3,366,682” to “$3,396,955”
Page 2	Line 11	Change “$122,012” to “$1,424,857”
Page 2	Line 12	Change “$19,204,685” to “$19,109,674”
Page 9	Line 3	Change “$15,715,991” to “$14,287,862”
Page 9	Line 5	Change “$3,366,682” to “$3,396,955”
Page 9	Line 6	Change “$122,012” to “$1,424,857”
Page 9	Line 7	Change “$19,204,685” to “$19,109,674”
Page 9	Line 10	Change “$0.16” to “$0.15”
Page 9	Line 21	Change “$1,001,967” to “$958,251”
Page 9	Line 23	Change “$1,441,877” to “$1,485,593”
Page 10	Line 1	Change “$1,437,032” to $1,483,506”
Page 10	Line 2	Change “$4,846” to “$2,086”
Page 11	Line 2	Change “$4,886,239” to “$4,839,764”
Page 11	Line 4	Change “$1,437,032” to “$1,483,506”
Page 11	Line 11	Change “$19,432,816” to “$19,342,894”
Page 11	Line 16	Change “$6,727,398” to “$6,634,789”
Page 11	Line 18	Change “$156,460” to “$159,146”
Page 12	Line 3	Change “$19,971,133” to “$19,837,496”
Page 12	Line 4	Change “$19,819,519” to “$19,680,436”
Page 12	Line 5	Change “$151,614” to “$157,060”
Page 12	Line 10	Change “$1,006,812” to “$960,338”
Page 12	Line 12	Change “$19,276,356” to “$19,183,748”
Page 12	Line 13	Change “$4,846” to “$2,086”
Page 12	Line 14	Change “$156,460” to “$159,146”
Page 13	Line 9	Change “$1,123,979” to “$2,383,108”
Page 13	Line 13	Change “$214,768” to “$1,044,362”
Page 13	Line 19	Change “$1,123,979” to “$2,383,108”
Page 14	Line 2	Change “$914,670” to “$911,804”
Page 14	Line 6	Change “$425,131” to “$427,998”
Page 14	Line 11	Insert after O&M “and refund of certain warranty claims”

Page 14	Line 11	Change "$279" to "$1,187,084"
Page 14	Line 18	Change "underrecovery" to "overrecovery"
Page 14	Line 19	Change "$776" to "$1,186,029"
Page 15	Line 2	Change "$5,687,438" to "$5,706,829"
Page 15	Line 4	Change "$783,511" to "$796,243"
Page 15	Line 9	Change "$36,542" to "$36,672"
Page 15	Line 9	Change "$83,888" to "$27,161"
Page 15	Line 10	Change "$83,888" to "$27,161"
Page 15	Line 11	Change "$120,429" to "$64,101"
Page 15	Line 12	Insert after Salvage "and an overrecovery of $267 of carrying charges related to the refund of warranty claims"
Page 15	Line 14	Change "$1,172,676" to "$879,794"
Page 15	Line 15	Change "$99,458" to "($202,677)"
Page 16	Line 5	Change "$228,131" to "$233,220"
Page 16	Line 7	Change "$228,477" to "$233,151"
Page 16	Line 9	Change "underrecovery" to "overrecovery"
Page 16	Line 9	Change "$346" to "$69"
Page 16	Line 18	Change "$4,255,142" to "$5,549,634"
Page 16	Line 20	Change "$2,903,032" to "$2,933,305"
Page 16	Line 22	Change "$1,123,979" to "$2,383,108"
Page 16	Line 23	Change "$228,131" to "$233,220"
Page 19	Line 18	Change "$15,715,991" to "$14,287,862"
Page 19	Line 20	Change "$3,366,682" to "$3,396,955"
Page 19	Line 22	Change "$122,012" to "$1,424,857"
Page 20	Line 1	Change "$19,204,685" to "$19,109,674"

MAY 1, 2014 EXHIBITS OF JENNIFER GRANT-KEENE

EXHIBIT JGK-7

<u>See Revised Exhibit JGK-7, Attached</u>
This revised exhibit reflects the total impact of all errata items on FPL's 2015 revenue requirements, a $1,428,129 decrease.

EXHIBIT JGK-8

EXHIBIT #	PAGE #	LINE #	
JGK-8	Page 1	Line 5, Column (E)	Change "$721,816,831" to "$721,796,230"
JGK-8	Page 1	Line 5, Column (F)	Change "$687,219,284" to "$687,199,671"
JGK-8	Page 1	Line 5, Column (G)	Change "($6,061,128)" to

			"($6,081,729)"
JGK-8	Page 1	Line 5, Column (H)	Change "($5,770,611)" to "($5,790,224)"
JGK-8	Page 1	Line 5, Column (J)	Change "$679,398,729" to "$679,379,338"
JGK-8	Page 1	Line 5, Column (K)	Change "($5,704,941)" to "($5,724,332)"
JGK-8	Page 1	Line 19	Change "($777,159)" to "($779,959)"
JGK-8	Page 1	Line 24, Column (E)	Change "$511,780,480" to "$511,776,630"
JGK-8	Page 1	Line 24, Column (F)	Change "$502,579,931" to "$502,576,150"
JGK-8	Page 1	Line 24, Column (G)	Change "($18,411)" to "($22,261)"
JGK-8	Page 1	Line 24, Column (H)	Change "($18,080)" to "($21,861)"

Note that these corrections affect other lines/columns (i.e., subtotals and totals) of this exhibit.

EXHIBIT JGK-9

EXHIBIT #			
JGK-9	Page 1	Line 6, Column (G)	Change "($2,628,707)" to "($2,930,842)"
JGK-9	Page 1	Insert after Line 33, Internal Order number P00000000761	
JGK-9	Page 1	Insert after Line 35, Internal Order number P00000000763	
JGK-9	Page 1	Line 34, Column (G)	Change "$707,172" to "$570,078"
JGK-9	Page 1	Line 62, Total	Change "$8,875,444" to "$8,582,562"
JGK-9	Page 1	Line 64, Total	Change "$1,172,676" to "$879,794"
JGK-9	Page 1	Line 62, Salvage	Change "$1,924,218" to "$1,631,336"

Note that these corrections affect other lines/columns (i.e., subtotals and totals) of this exhibit. The result of these corrections is a $595,017 decrease in the Total 2012 & 2013 NBV of Retirements, Removal & Salvage.

Exhibit JGK-11

See Attached Exhibit JGK-11 Revised for Errata

The Revised Exhibit JGK-11 reflects the $1,428,129 decrease to FPL's requested 2015 revenue requirements.

PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JENNIFER GRANT-KEENE

DOCKET NO. 140009-EI

May 1, 2014

Q. Please state your name and business address.

A. My name is Jennifer Grant-Keene. My business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

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

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the $15,715,991 revenue requirements that FPL is requesting to recover through the Capacity Cost Recovery Clause (CCRC) in 2015. These revenue requirements are summarized in my Exhibit JGK-7 and shown in FPL's Nuclear Filing Requirement Schedules (NFRs) filed in this docket. Included in these revenue requirements is FPL's final true-up from the 2013 True-Up (T) Schedules filed in this docket on March 3, 2014. In addition, I provide an overview of the components of the revenue requirements included in FPL's filing and demonstrate that the filing complies with the Florida Public Service Commission (FPSC or Commission) Rule No. 25-6.0423, Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery (Nuclear Cost Recovery Rule or NCR Rule). I also discuss the accounting controls FPL relies upon to ensure only appropriate costs are charged to the projects.

Q. Please summarize your testimony.

A. FPL is requesting to recover $15,715,991 in revenue requirements in 2015. These revenue requirements are based on:

(1) The final true-up of 2013 costs resulting in an overrecovery of $3,366,682;

(2) The Actual/Estimated true-up of 2014 costs resulting in an overrecovery of $122,012; and

(3) Revenue requirements of $19,204,685 related to the Projection of 2015 costs.

FPL's 2014 Actual/Estimated (AE) and 2015 Projected (P) Schedules comply with the Nuclear Cost Recovery Rule and reflect information subject to the robust and comprehensive corporate and overlapping business unit controls for incurring and validating costs and recording transactions associated with FPL's Turkey Point 6 & 7 (TP 6 & 7 or New Nuclear) and Extended Power Uprate (EPU or Uprate) Projects.

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

A. Yes. I am sponsoring the following exhibits:

- Exhibit JGK-7, 2015 Revenue Requirements, summarizes the revenue requirements requested to be recovered in 2015. These amounts include the results of the 2013 T NFRs filed in this docket on March 3, 2014, the 2014 AE NFRs, and the 2015 P NFRs . The NFRs detail the components of cost by project, by year and by category of costs being recovered. For the TP 6 & 7 Project this includes Site Selection and Pre-construction costs, and carrying costs on unrecovered balances and on the deferred tax asset/liability. For the EPU Project, this includes carrying costs on construction costs and on the deferred tax asset/liability as well as interest on underrecovered O&M costs. In addition, base rate revenue requirements, including carrying charges for 2012 and 2013 reductions of plant placed into service, but not yet included in base rates is also presented.

- Exhibit JGK-8, St. Lucie and Turkey Point Uprate Project 13 Month Average of Reduction in 2012 and 2013 Plant Placed into Service as of December 31, 2013 shows the calculation of the revenue requirements related to the difference between FPL's Actual 2012 and 2013 Plant Placed into Service as filed in FPL's March 3, 2014 filing and the amount currently being recovered in base rates effective January 2, 2014 as filed in Docket No 130245-EI.
- Exhibit JGK-9, St. Lucie and Turkey Point Uprate Project, Actual Net Book Value of Retirements, Removal Cost & Salvage for Plant Placed into Service in 2013 shows the calculation of the return on the difference between FPL's 2013 Actual Net Book Value of Retirements, Removal

Cost and Salvage and the amount currently being recovered in base rates effective January 2, 2014 as filed in Docket No 130245-EI.

- Exhibit JGK-10, EPU NFR Schedules, includes certain 2014 AE Schedules, 2015 P Schedules, and 2015 True-Up to Original (TOR) Schedules. The EPU TOR-2 Schedule included in JGK-10 is co-sponsored by FPL Witness Jones.
- Exhibit JGK-11, Nuclear Cost Recovery Bill Impact, shows the NCRC component as a portion of a typical residential customer's overall bill.

I additionally sponsor or co-sponsor some of the NFRs included in Exhibits sponsored by FPL Witness Scroggs as described below.

- Exhibit SDS-7, Turkey Point 6 & 7 Site Selection and Pre-construction NFR Schedules, consists of 2014 AE Schedules, 2015 P Schedules, and 2015 TOR Schedules. The NFRs contain a table of contents listing the schedules sponsored and co-sponsored by FPL Witness Scroggs and me, respectively.

NUCLEAR FILING REQUIREMENT SCHEDULES

Q. Please describe the NFRs you are filing with this testimony.

A. For the TP 6 & 7 Project, FPL is filing its 2014 AE, 2015 P, and 2015 TOR Schedules consistent with the requirements of the NCR Rule to provide an overview of the financial and construction aspects of its new nuclear power plant projects, outline the categories of costs represented, and provide the calculation of detailed project revenue requirements. FPL previously filed its 2013 T Schedules on March 3, 2014 in this docket. My testimony refers to Exhibits that include the 2014 AE Schedules, 2015 P Schedules, and the 2015 TOR Schedules. The 2015 TOR Schedules provide an updated summary of the cumulative project costs.

The EPU Project was completed in 2013 and no additional construction or O&M costs will be incurred in 2014. However, FPL will refund or collect any over/under recoveries resulting from its 2013 and 2014 true-ups in 2015. Therefore, FPL is filing 2014 AE, 2015 P and 2015 TOR Schedules, to show the refund/recovery, along with related carrying charges or interest expense on any over/under recoveries of carrying charges, base rate revenue requirements or O&M expenses as a result of the 2013 final true-up filed in this docket.

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

A. Yes. The Nuclear Cost Recovery Rule states:

"1. Each year . . . a utility shall submit, for Commission review and approval, as part of its cost recovery filings: …

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

Q. Is FPL complying with these requirements with respect to its 2014 Actual/Estimated TP 6 & 7 and EPU Project costs?

A. Yes. FPL has included for the TP 6 & 7 Project the 2014 AE Schedules in Exhibit SDS-7 for Site Selection and Pre-construction costs. FPL has included for the EPU Project applicable 2014 AE Schedules in Exhibit JGK-10 necessary for the true-up of base rate revenue requirements, carrying charges, and interest on net overrecoveries of prior years' costs.

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

A. Yes. The Nuclear Cost Recovery Rule states:

"1. Each year . . . a utility shall submit, for Commission review and approval, as part of its cost recovery filings: ...

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

Q. Is FPL complying with these requirements with respect to its 2015 Projected TP 6 & 7 Project and EPU Project costs?

A. Yes. FPL has included for the TP 6 & 7 Project the 2015 P Schedules in Exhibit SDS-7 for Site Selection and Pre-construction costs. FPL has included for the EPU Project applicable 2015 P Schedules in Exhibit JGK-10 to show the refund of net overrecoveries of costs as well as the carrying charges or interest on the overrecoveries of costs on the final True-up of 2013 costs and on the Actual/Estimated True-up of 2014 costs. My Exhibit JGK-7, details the true up of 2013 actual costs (as filed on March 3, 2014 in this docket), and the 2014 Actual/Estimated and 2015 Projected revenue requirements FPL is filing now and requesting to recover in 2015.

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

A. FPL has included for the TP 6 & 7 Project the 2015 TOR Schedules in Exhibit SDS-7 for Site Selection and Pre-construction costs. FPL has included for the EPU Project applicable 2015 TOR Schedules in Exhibit JGK-10. The TOR Schedules follow the format of the T, AE, and P Schedules, but also detail the actual to date project costs and projected total retail revenue requirements for the duration of the project based on the best available information prior to this filing.

- Schedule TOR-1 - Reflects the jurisdictional amounts used to calculate the final true-up, Actual/Estimated true-up, projection, deferrals, and requested recovery amounts for each project included in the NCRC.
- Schedule TOR-2 - Reports the budgeted and actual costs as compared to the estimated in-service costs of the power plant as provided in the petition for need determination or revised estimate if necessary.
- Schedule TOR-3 - Provides a summary of the actual amounts through 2013 and projected total amounts for the project.
- Schedule TOR-4 - Provides the annual construction O&M expenditures by function as reported for all historical years through 2013, for the current year, and for the projected year.
- Schedule TOR-6 - Provides the actual expenditures through 2013 and projected annual expenditures by major tasks performed within Site Selection and Pre-construction.
- Schedule TOR-6A - Provides a description of the major tasks performed within the Site Selection and Pre-construction category for the year filed.
- Schedule TOR-7 - Reflects initial project milestones in terms of costs, budget levels, initiation dates, and completion dates as well as all revised milestones and reasons for each revision.

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

A. FPL's sunk costs for the TP 6 & 7 Project are approximately $228 million as of December 31, 2013.

Q. Please explain the components of the revenue requirements that FPL is requesting to include for recovery effective January 2, 2015.

A. The total amount FPL is requesting to recover in 2015 is $15,715,991. This amount reflects the true-up to 2013 actual costs as filed on March 3, 2014 representing an overrecovery of $3,366,682, the overrecovery of 2014 Actual/Estimated costs of $122,012, and the recovery of 2015 Projected costs of $19,204,685 as shown on Exhibit JGK-7.

Q. What is the projected 2015 residential customer bill impact based on 2015 NCRC revenue requirements?

A. The projected residential customer monthly bill impact for 2015 is $0.16 per 1,000 kWh. This is a reduction of more than 65% of FPL's currently authorized nuclear cost recovery amount of $0.46 per 1,000 kWh. Exhibit JGK-11 shows the NCRC component in comparison to a typical residential customer's overall bill.

TURKEY POINT 6 & 7 PROJECT

Actual/Estimated Revenue Requirements - 2014

Q. What is the revenue requirement amount that FPL is requesting to reflect in the true-up of its 2014 TP 6 & 7 Project costs?

A. FPL is requesting $1,001,967 in revenue requirements, which represents an underrecovery of Pre-construction costs of $2,443,844, and an overrecovery of carrying costs of $1,441,877 as shown on Exhibit JGK-7. The overrecovery of carrying costs of $1,437,032 is attributed to Pre-construction, while Site Selection accounts for $4,846. The true-up of 2014 Site Selection costs pertains to the recovery of carrying costs remaining on the deferred tax asset for Site Selection as well as a reduction in carrying charges due to the decrease in the Allowance for Funds Used During Construction (AFUDC) rate effective January 1, 2014. FPL Witness Scroggs's Exhibit SDS-7, Schedules AE-2 and AE-3A, summarize the revenue requirements identified above. This amount is being requested to be reflected in the CCRC charge paid by customers when the CCRC is reset in 2015.

Q. What are FPL's 2014 Actual/Estimated TP 6 & 7 Project Pre-construction expenditures compared to costs previously projected and any resulting (over)/under recoveries of costs?

A. FPL's Actual/Estimated TP 6 & 7 Project Pre-construction expenditures for the period January through December 2014 are $20,240,628 ($19,270,470 on a jurisdictional basis) as presented in FPL Witness Scroggs's testimony and provided on Exhibit SDS-7, Schedule AE-6. FPL's previous projected 2014 Pre-construction expenditures were $16,826,626 on a jurisdictional basis. The result is an underrecovery of Pre-construction revenue requirements of $2,443,844.

Q. What are FPL's 2014 actual/estimated TP 6 & 7 Project Pre-construction and Site Selection carrying charges compared to carrying charges previously projected and any resulting (over)/under recoveries of costs?

A. FPL's 2014 actual/estimated TP 6 & 7 Project Pre-construction carrying charges are $4,886,239. FPL's previous projected carrying charges were $6,323,270, resulting in an overrecovery of revenue requirements of $1,437,032. The calculations of the carrying charges can be found in Exhibits JGK-7 and SDS-7, Schedules AE-2 and AE-3A.

Projected Revenue Requirements - 2015

Q. What revenue requirement amount is FPL requesting for its 2015 projected TP 6 & 7 Project costs?

A. FPL is requesting recovery of $19,432,816 in revenue requirements related to its projected 2015 TP 6 & 7 Project Site Selection and Pre-construction costs. These revenue requirements consist of projected TP 6 & 7 Project Pre-construction expenditures of $13,180,727 ($12,548,959 on a jurisdictional basis) as presented in FPL Witness Scroggs's testimony and provided in Exhibit SDS-7, Schedule P-6, and projected carrying charges of $6,727,398 as shown in Exhibit SDS-7, Schedule P-2 and P-3A. Also included are projected TP 6 & 7 Project Site Selection carrying costs of $156,460 as shown on Exhibit JGK-7.

TP 6 & 7 Project Summary

Q. What is the total amount FPL is requesting to recover in its 2015 NCRC CCRC factor for the TP 6 & 7 Project?

A. FPL is requesting to include $19,971,133 of revenue requirements in 2015 for TP 6 & 7 Project of which $19,819,519 is for Pre-construction costs and $151,614 is attributed to carrying costs for Site Selection.

This total amount consists of the true-up of 2013 actual TP 6 & 7 Project Pre-construction costs and carrying costs of $463,650 (overrecovery), described in my March 3, 2014 testimony; the true-up of 2014 Actual/Estimated TP 6 & 7 Project Pre-construction costs and carrying costs of $1,006,812 (underrecovery); 2015 Pre-construction costs and carrying costs of $19,276,356; the 2014 Actual/Estimated Site Selection carrying costs of $4,846 (overrecovery); and the 2015 Projected TP 6 & 7 Project Site Selection carrying costs of $156,460, as shown on Exhibit JGK-7.

For the reasons stated in FPL Witness Scroggs's testimony, FPL respectfully requests that the Commission approve the 2014 Actual/Estimated, and 2015 Projected costs and the resulting Pre-construction and Site Selection carrying charges as reasonable, and approve the revenue requirements described in my testimony for recovery in FPL's 2015 CCRC charge.

EPU PROJECT

Actual/Estimated Revenue Requirements - 2014

Q. What are FPL's 2014 Actual/Estimated EPU Project expenditures compared to costs previously projected?

A. FPL completed the EPU Project in 2013 so there were no project expenditures projected for 2014 and therefore there is no actual/estimated true-up required.

Q. What is the amount that FPL is requesting to reflect as the true-up of its 2014 Actual/Estimated EPU Project revenue requirements?

A. FPL's requested true-up of its 2014 revenue requirements for the EPU Project is an overrecovery of $1,123,979.

Q. Please describe the components of FPL's 2014 Actual/Estimated EPU true-up.

A. The 2014 Actual/Estimated revenue requirements for the EPU Project are $214,768. These revenue requirements are comprised of prior years' over/under recoveries related to carrying charges, interest on recoverable O&M, base rate revenue requirements for plant placed into service in 2012 and 2013, and carrying charges on incremental Net Book Value of Retirements, Removal Costs and Salvage. FPL's previously projected revenue requirements were $1,338,746, resulting in an overrecovery of $1,123,979. The details of these jurisdictional costs (carrying charges, interest on recoverable O&M and carrying charges on base rate revenue requirements) are summarized on Exhibit JGK-7.

Q. Where can the calculation of FPL's EPU Project 2014 Actual/Estimated carrying charges related to prior years be found?

A. The calculation of the EPU Project 2014 Actual/Estimated carrying charges on prior years' underrecoveries of $914,670 can be found in Exhibit JGK-7, Exhibit JGK-10, and Schedule AE-3. FPL's previous Projected 2014 EPU carrying costs on prior years' underrecoveries were $1,339,801 as filed in Docket No. 130009-EI. As a result of the Actual/Estimated true-up of 2014 carrying costs in this filing, there is an overrecovery of $425,131 in 2014.

Q. What is FPL's EPU Project 2014 Actual/Estimated interest on over/underrecoveries of recoverable O&M and where can this calculation be found?

A. FPL's EPU Project 2014 Actual/Estimated interest on overrecoveries of recoverable O&M is $279 jurisdictional, net of participants, and can be found in Exhibit JGK-7 and Exhibit JGK-10, Schedule AE-4. FPL previously projected 2014 interest on overrecoveries of recoverable O&M of $1,055, jurisdictional, net of participants, as filed in Docket No. 130009-EI. As explained in Schedule AE-4, over/underrecoveries of recoverable O&M incur interest at the AA Financial 30-day rate posted on the Federal Reserve website. As a result of the Actual/Estimated true-up of 2014 EPU Project interest on underrecoveries of recoverable O&M, there is an underrecovery of $776, jurisdictional, net of participants in 2014.

Q. Please explain the revenue requirements and carrying charges associated with the true-up of the 2014 Projected carrying costs as shown on JGK-7.

A. FPL is including in this filing additional true-ups to 2012 and 2013 plant placed into service subsequent to filing the 2013 Base Rate Increase in Docket

No. 130245-EI. Exhibit JGK-8 shows reductions of $56,960 for 2012 and $5,687,438 for 2013 plant placed into service. The reduction in plant placed into service resulted in an overrecovery of base rate revenue requirements in the amount of $783,511 as shown on Exhibit JGK-7 and detailed in Exhibit JGK-8 and Exhibit JGK-10, Appendix C.

The overrecovered revenue requirements attributed to reduction in plant placed into service during 2013 accrued carrying charges to be refunded in the amount of $36,542 and reduced total carrying charges to a total of $83,888 as shown on Exhibit JGK-7 and Appendix C. The remainder of the $83,888 of carrying costs is attributed to an underrecovery of $120,429 of Incremental Net Book Value of Retirements, Removal Costs & Salvage for which FPL is requesting recovery. The additional 2012 and 2013 Net Book Value of Retirements, Removal Costs & Salvage, in the amounts of $1,172,676 and $99,458 respectively, were identified subsequent to filing the 2013 Base Rate Increase Petition in Docket No. 130245-EI and are shown in Exhibit JGK-10, Appendix C, and detailed on Exhibit JGK-9.

Projected Revenue Requirements – 2015

Q. Please describe the P Schedules you are filing for 2015 for the EPU Project.

A. FPL is filing P-1, P-3 and P-4 Schedules for 2015 to show the impacts of refunding its 2013 final true-up and 2014 Actual/Estimated true-up for 2014.

Q. Please describe what each of these P-Schedules includes.

A. The P-1 Schedule summarizes what FPL will refund from Schedules P-3 and P-4 in 2015 and shows an overrecovery of $228,131 of revenue requirements. Exhibit JGK-10, Schedule P-3, presents the calculation of the EPU Project 2015 projected carrying costs on prior years' overrecoveries of $228,477 as shown on Exhibit JGK-7. Schedule P-4 shows the EPU Project 2015 projected underrecovery of interest of $346 on O&M and is shown in Exhibit JGK-7. As explained in Exhibit JGK-10, Schedule P-4, all over/under recoveries on recoverable O&M incur interest at the AA Financial 30-day rate posted on the Federal Reserve Board website.

EPU Project Summary

Q. What is the amount FPL is requesting to refund through the CCRC factor for the EPU Project in 2015?

A. FPL is requesting to refund $4,255,142 for the EPU Project in 2015. This amount consists of carrying charges and interest on the true-up of 2013 EPU Project revenue requirements on overrecovered costs of $2,903,032 described in my March 3, 2014 testimony, the true-up of 2014 overrecovered Actual/Estimated EPU Project revenue requirements of $1,123,979, and 2015 projected EPU revenue requirements on overrecoveries of costs of $228,131.

FPL respectfully requests that the Commission approve FPL's 2014 Actual/Estimated revenue requirements and the resulting refund of revenue requirements as well as the 2015 refund of revenue requirements as reasonable.

ACCOUNTING CONTROLS

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

A. As described more fully in my March 3, 2014 testimony, FPL has a robust system of corporate accounting controls. The Company relies on its comprehensive corporate and overlapping business unit controls for recording and reporting transactions associated with any of its capital projects including the TP 6 & 7 Project and EPU Project. Highlights of the Company's comprehensive and overlapping controls which continue to be utilized in 2014 for the TP 6 & 7 Project include:

- FPL's accounting policies and procedures;
- Financial systems and related controls including FPL's general ledger and construction asset tracking system;
- FPL's annual budgeting and planning process;
- Reporting and monitoring of planned costs to actual costs incurred; and

- Business unit specific controls and processes.

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

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

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

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

Q. Did anything change in the method incremental labor is established from 2013 to 2014?

A. No. The basis that was established in 2013, as a result of FPL's rate case in Docket No. 120015-EI, is the basis used for 2014. Employees dedicated to the project and charging 100% of their time to the NCRC projects during 2013 are considered incremental for the entire year 2013 and as a result, incremental for 2014. Employees charging a percentage of their time to capital in the NCRC in 2013 are designated incremental for that percentage of their labor costs in 2013 and 2014.

CONCLUSION

Q. What is the total revenue requirement FPL is requesting the Commission approve for the 2015 CCRC factor?

A. FPL is requesting that the Commission approve recovery of $15,715,991 in revenue requirements through the 2015 CCRC factor. This amount consists of a true-up resulting in an overrecovery of $3,366,682 in revenue requirements as calculated in the 2013 T Schedules filed on March 3, 2014, a true-up resulting in an overrecovery of $122,012 in revenue requirements as calculated in the 2014 AE Schedules, and $19,204,685 in revenue requirements as calculated in the 2015 P Schedules.

FPL is also requesting the Commission determine that FPL's 2014 Actual/Estimated and 2015 Projected costs and the resulting revenue requirements are reasonable as supported by Exhibit JGK-7 and the testimonies and exhibits filed by other FPL witnesses in this docket.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO. 140009-EI

May 1, 2014

Q. Please state your name and business addresses.

A. My name is Steven R. Sim, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Integrated Resource Planning in the Resource Assessment & Planning Department.

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

A. I supervise and coordinate analyses that are designed to determine the magnitude and timing of FPL's resource needs and then develop the integrated resource plan with which FPL will meet those resource needs.

Q. Please describe your education and professional experience.

A. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles (UCLA) in 1979.

While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center during 1977 - 1979. My responsibilities at the Florida Solar Energy Center included an evaluation of Florida consumers' experiences with solar water heaters and an analysis of potential renewable energy resources including photovoltaics, biomass, wind power, etc., applicable in the Southeastern United States.

In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities included the development, monitoring, and cost-effectiveness analyses of demand side management (DSM) programs. In 1991 I joined my current department, then named the System Planning Department, where I held different supervisory positions dealing with integrated resource planning. In late 2007 I assumed my present position.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to present the results of the 2014 economic analyses for the new FPL nuclear units, Turkey Point 6 & 7. Non-economic analyses of Turkey Point 6 & 7 were also performed. In my testimony I will refer to these analyses collectively as the 2014 feasibility analyses for the Turkey Point 6 & 7 project. The results of these analyses were that the Turkey Point 6 & 7 project is projected to be the clear economic choice in at least half of these scenarios and that FPL's customers will also benefit greatly from non-economic aspects of the project such as enhanced fuel diversity and lower system emissions.

In addition, I will briefly discuss FPL's portfolio approach in resource planning and the role of additional nuclear energy in that portfolio approach. I will also discuss the assumptions used in the 2014 feasibility analyses. I will also present the results of additional analyses that further quantify the projected benefits of the Turkey Point 6 & 7 project.

The 2014 feasibility analyses of the Turkey Point 6 & 7 project are presented to satisfy the requirement of Subsection 6(c)5 of the Florida Administrative Code Rule 25-6.0423, Nuclear Power Plant Cost Recovery, which states *"Along with the filings required by this paragraph, each year a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the power plant."* Other feasibility-related topics for the Turkey Point 6 & 7 project are discussed by FPL Witness Scroggs.

Q. Please summarize your testimony.

A. In 2014, FPL performed new feasibility analyses using updated assumptions and forecasts. These analyses utilized 3 fuel cost forecasts, 3 environmental cost forecasts, and two operating life assumptions. In total, 14 scenarios were analyzed. The results of FPL's 2014 feasibility analyses indicate that completing the project is projected to be clearly economic for FPL's customers in 7 of these 14 scenarios which showed that the projected breakeven capital costs for the two new nuclear units were above the high end of FPL's non-binding capital cost estimate. In the remaining 7 scenarios, the breakeven capital costs fell within the range of these non-binding capital cost estimates in 6 of these scenarios. The Turkey Point 6 & 7 units were projected to be non-economic (but nonetheless beneficial in terms of fuel diversification and emission reductions) in only one scenario. This single scenario assumed low natural gas costs for each year through the year 2063, low environmental compliance costs for each year through the year 2063, and also assumed the lower of the two operating life assumptions.

The results of the 2014 feasibility analyses are summarized in Exhibit SRS-1. This exhibit presents a number of results from FPL's 2014 analyses of the Turkey Point 6 & 7 project including, but not limited to: (i) the number of future fuel cost, environmental cost, and operating life scenarios in which the project is projected to be clearly economic; (ii) projected fuel savings for FPL's customers; (iii) reduced reliance upon fossil fuels (i.e., fuel diversity); and (iv) projected carbon dioxide (CO_2) reductions. These results, and results of other analyses and calculations, are discussed later in my testimony.

These results, whether examined individually or as a whole, present a strong case for continuing the Turkey Point 6 & 7 project. For example, based on the Medium Fuel Cost forecast, customers are projected to save at least $64 billion (nominal) in fuel costs over the life of Turkey Point 6 & 7. Additionally, the project will produce energy that otherwise would have required the consumption of substantial amounts of natural gas or millions of barrels of oil annually, and will reduce system CO_2 emissions by millions of tons. In short, completing Turkey Point 6 & 7 continues to be projected as a valuable resource addition for FPL's customers as part of FPL's portfolio approach to resource planning.

Q. Would you please briefly explain what you mean by FPL's portfolio approach to resource planning and what part additional nuclear capacity such as Turkey Point 6 & 7 plays in that portfolio approach?

A. Yes. As with all economic analyses, FPL's 2014 economic analyses of the Turkey Point 6 & 7 project provides a "snapshot" of the projected customer benefits associated with Turkey Point 6 & 7 based on current project assumptions, forecasts of numerous costs, and resource planning assumptions. The 2014 feasibility analyses examine potential future scenarios that result from combining various fossil fuel price forecasts, environmental compliance cost forecasts, and operating lives. Of course, the actual economic performance of FPL's system, including the impacts of future fuel prices, etc., cannot be known until after the fact. That is why FPL examines the projected impacts of resource additions such as new nuclear capacity over a wide range of potential future scenarios.

The inability to be able to predict with confidence future fuel and environmental compliance costs is a key reason why FPL not only performs these analyses based on multiple forecasts and scenarios, but also why FPL strives for diversity in regard to system resources and fuels in what I will refer to as a portfolio approach to resource planning. Because the price of nuclear fuel is unrelated to fossil fuel prices, and because nuclear power plants produce no emissions such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), or carbon dioxide (CO_2) in the process of generating electricity, additional nuclear capacity is a superb hedge against fossil fuel price volatility and increases in environmental compliance costs. Diversification also improves system reliability.

The Turkey Point 6 & 7 nuclear project will help reduce FPL's reliance on natural gas. In addition, the Turkey Point 6 & 7 nuclear project will also help further reduce the usage of oil, including foreign oil, by FPL's system. Through diversification generally, and the addition of Turkey Point 6 & 7, FPL is working to keep its electric rates, and thus the resulting bills for its customers, low over the long term while also providing highly reliable electric service.

The current low cost of natural gas is a great thing for FPL's customers because it allows FPL to produce electricity with relatively low fuel costs. The current forecasted low cost of natural gas is also a primary reason that highly efficient gas-fired combined cycle (CC) units have been determined to be the most economic type of fossil fueled generation resource for FPL's system when FPL has needed to add new generation resources. As a result of these factors, FPL has been increasing its use of natural gas to benefit its customers and now supplies approximately 2/3 of all of the electricity it provides to customers by burning natural gas.

However, this increased use of natural gas also represents a growing reliance on natural gas. In turn, this growing reliance on natural gas results in increased risk in regard to potential future changes in natural gas cost and availability.

Consequently, FPL's resource planning takes a balanced portfolio approach to maximize the benefits to customers of using currently low cost natural gas while also taking steps to minimize the risks inherent in having a high reliance on natural gas. Among the steps being taken to minimize this risk are: (i) selecting high-efficiency CC generating units, which burn natural gas as efficiently as possible, when FPL's resource needs dictate that new generating units should be added; (ii) enhancing the availability of natural gas by pursuing a third natural gas pipeline into Florida (which may also put downward pressure on delivered natural gas prices); (iii) maintaining the ability to continue to burn fuel oil in existing steam generating units by installing electrostatic precipitators at these units; (iv) diversifying FPL's fuel mix by pursuing additional renewable energy; and (v) significantly diversifying FPL's fuel mix by adding additional nuclear capacity through the successfully completed Extended Power Uprate (EPU) project and the Turkey Point 6 & 7 project.

Additional nuclear capacity is an important aspect of this balanced portfolio approach because it is the only resource option available that can provide baseload, firm capacity at even lower fuel costs than natural gas and which does so using no fossil fuels and producing zero air emissions. In regard to the latter two points - no fossil fuel use and producing zero air emissions - nuclear capacity serves as an excellent hedge against increasing natural gas costs and increasing environmental compliance costs as previously mentioned. These hedge aspects of nuclear capacity are especially valuable attributes in a balanced portfolio approach to serving FPL's customers both today and in the future.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following 10 exhibits:

- Exhibit SRS-1: Summary of Results from FPL's 2014 Feasibility Analyses of the Turkey Point 6 & 7 Project (Plus Results from Additional Analyses);
- Exhibit SRS-2: Comparison of Key Assumptions Utilized in the 2013 and 2014 Feasibility Analyses of the Turkey Point 6 & 7 Project: Projected Fuel Costs (Medium Fuel Cost Forecast);

- Exhibit SRS-3: Comparison of Key Assumptions Utilized in the 2013 and 2014 Feasibility Analyses of the Turkey Point 6 & 7 Project: Projected Environmental Compliance Costs (Env II Forecast);
- Exhibit SRS-4: Comparison of Key Assumptions Utilized in the 2013 and 2014 Feasibility Analyses of the Turkey Point 6 & 7 Project: Summer Peak Demand Load Forecast;
- Exhibit SRS-5: Projection of FPL's Resource Needs Through 2025;
- Exhibit SRS-6: Comparison of Key Assumptions Utilized in the 2013 and 2014 Feasibility Analyses of the Turkey Point 6 & 7 Project: Other Assumptions;
- Exhibit SRS-7: The Two Resource Plans Utilized in FPL's 2014 Feasibility Analyses of the Turkey Point 6 & 7 Project;
- Exhibit SRS-8: 2014 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case # 1 Analysis – 40-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2014$ (millions, CPVRR, 2014-2063);
- Exhibit SRS-9: 2014 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case # 2 Analysis – 60-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2014$ (millions, CPVRR, 2014-2083); and,

- Exhibit SRS-10: A Look at Projected Hedge Benefits from Turkey Point 6 & 7.

I. 2014 Feasibility Analyses – Analytical Approach

Q. Please provide an overview of the basic analytical approach used for evaluating the Turkey Point 6 & 7 project.

A. The basic analytical approach in the feasibility analyses of Turkey Point 6 & 7 is to compare competing resource plans. FPL utilizes resource plans in its analyses in order to ensure that all relevant impacts to the FPL system are accounted for.

The analysis of each resource plan is a complex undertaking. For each resource plan, annual projections of system fuel costs and emission profiles are developed for various scenarios of fuel cost/environmental compliance costs using a sophisticated production costing model. This model, the P-MArea model, simulates the FPL system and dispatches all of the generating units on an hour-by-hour basis for each year in the analysis. The resulting fuel cost and emission profile information is then combined with projected annual capital costs, plus other fixed and variable costs for each resource plan. In this way, a comprehensive set of projected annual costs, for each year of the analysis, is developed for each resource plan.

One resource plan includes the Turkey Point 6 & 7 units. The other resource plan includes instead an alternate resource option that competes with these two nuclear units. The competing alternate resource option is new highly fuel-efficient CC generating capacity consistent with the CC capacity that has recently been installed at FPL's Cape Canaveral and Riviera Beach sites, and which is currently being installed at FPL's Port Everglades site, through FPL's modernization projects at these sites.

The competing resource plans are then analyzed over a multi-year period. This approach allows FPL's analyses to account for both short-term and long-term economic impacts of the resource options being evaluated. FPL's 2014 feasibility analyses address these economic impacts. In addition, my testimony provides a discussion of three non-economic impacts to the FPL system: system fuel savings, increased system fuel diversity, and system emission reductions, which will result from the Turkey Point 6 & 7 project.

Q. Has the Florida Public Service Commission (FPSC) provided guidance regarding what is required in the feasibility analyses?

A. Yes. The FPSC first provided guidance in its affirmative determination of need order for Turkey Point 6 & 7 (Order No. PSC-08-0237-FOF-EI, page 29), when it stated:

> *"FPL shall provide a long-term feasibility analysis as part of its annual cost recovery process which, in this case, shall also include updated fuel costs, environmental forecasts, break-even costs, and*

capital cost estimates. In addition, FPL should account for sunk costs. Providing this information on an annual basis will allow us to monitor the feasibility regarding the continued construction of Turkey Point 6 and 7."

In the FPSC's 2009 Nuclear Cost Recovery (NCR) order (Order No. PSC-09-0783-FOF-EI, page 14), the FPSC quoted its need determination order and reiterated that these elements are necessary to satisfy the NCR Rule.

This guidance from the FPSC clearly distinguishes "sunk costs" from "updated capital cost estimates" in regard to feasibility analyses of nuclear projects. Consequently, FPL has effectively removed sunk costs in its calculation of breakeven costs for the feasibility analyses of Turkey Point 6 & 7. FPL's approach to sunk costs complies with the above mentioned Rule, which directs FPL to evaluate "completing" the project. FPL's approach to sunk costs also follows the guidance provided by the FPSC, and was expressly approved for the Turkey Point 6 & 7 analyses by the FPSC in its 2011 NCR order (Order No. PSC-11-0547-FOF-EI, pages 17-18 and 38).

Q. Was the analytical approach used in FPL's 2014 feasibility analyses of Turkey Point 6 & 7 similar to the approach used in the Determination of Need filings for this project, and in the feasibility analyses of this project that were presented in previous NCR filings?

A. Yes. The analytical approach that was used in the 2014 feasibility analyses for the Turkey Point 6 & 7 project is very similar to the approach used in the 2007 Determination of Need filing and in the feasibility analyses presented in the 2008 through 2013 NCR filings.

Q. Please describe the economic perspective used in the analytical approach for the Turkey Point 6 & 7 project.

A. This perspective is the calculation of breakeven overnight capital costs, in terms of both cumulative present value of revenue requirements (CPVRR) and overnight construction costs in $/kW, for the new nuclear units. This same perspective was utilized in the 2007 Determination of Need filing, and in the 2008 through 2013 NCR filings, for the Turkey Point 6 & 7 project. In later years, as more information becomes available regarding the cost and other aspects of the new nuclear units, another perspective may emerge as more appropriate.

II. 2014 Feasibility Analyses – Updated Assumptions

Q. Do FPL's 2014 feasibility analyses utilize updated assumptions for the specific information referred to in the previously mentioned FPSC Order?

A. Yes. FPL typically seeks to utilize a set of updated assumptions in its resource planning work. FPL updated these assumptions in late 2013/early

2014 and is using them in its 2014 resource planning work including the nuclear analyses presented in this docket.

Five informational items were listed in Order No. PSC-08-0237 that should be updated and included in FPL's annual long-term feasibility analyses of Turkey Point 6 & 7. These five items are:

1) fuel forecasts;
2) environmental compliance cost forecasts;
3) breakeven costs;
4) capital cost estimates; and,
5) sunk costs.

FPL's 2014 feasibility analyses for the Turkey Point 6 & 7 project utilized FPL's current assumptions for four of these five items and calculated the current projected value for the fifth item. FPL's 2014 feasibility analyses for the Turkey Point 6 & 7 project included current assumptions for the following four items: items 1), 2), 4), and 5). The remaining item, item 3) breakeven costs, is a result of the analyses (as opposed to an assumption). The results of FPL's 2014 feasibility analyses present updated breakeven costs for the Turkey Point 6 & 7 project in terms of CPVRR costs and in terms of overnight construction costs in $/kW.

Q. Do FPL's feasibility analyses include FPL's updated assumptions for information other than these 5 items?

A. Yes. FPL also updated a number of other assumptions in late 2013/early 2014 in preparation for all of its 2014 resource planning work. Consequently, these other updated assumptions are also included in FPL's 2014 feasibility analyses of the Turkey Point 6 & 7 project. A partial listing of these other assumptions include: FPL's load forecast and cost and performance assumptions for new CC capacity.

Q. Please discuss any changes in the forecasted values for fuel costs and environmental compliance costs between the forecasts utilized in the 2014 feasibility analyses and those that were used in the 2013 feasibility analyses.

A. Exhibits SRS-2 and SRS-3 provide these comparisons. Exhibit SRS-2 provides 2013 and 2014 forecasted Medium Fuel Cost values for selected years for natural gas, oil, and nuclear fuel costs. As shown in this exhibit, the 2014 Medium Fuel Cost forecasts for natural gas and for 1% sulfur oil are lower than the respective 2013 forecasts throughout all years. In regard to forecasted nuclear fuel costs, the 2014 forecasted prices are unchanged from the 2013 forecasted prices.

Exhibit SRS-3 presents similar 2013 and 2014 comparative information for forecasted Env II (i.e., mid-level) environmental compliance costs for three types of air emissions: SO_2, NO_x, and CO_2. As shown in the exhibit, there has been no change in projected environmental compliance costs for these three types of air emissions from what was assumed in FPL's 2013 feasibility analyses. The decision not to change these projected compliance costs was based on FPL's view that nothing definitive had occurred on either the legislative or regulatory fronts since the 2013 NCR docket hearing that would require a change in these cost projections. As in FPL's 2012 and 2013 analyses, these projected environmental compliance costs are lower than the projected costs used in FPL's nuclear analyses from 2007 through 2011.

Q. Are any of the fuel cost forecasts or environmental compliance cost forecasts considered the "most likely" forecast?

A. FPL does not consider any fuel cost forecast or environmental cost forecast as the "most likely" cost forecast. FPL's scenario approach is designed to provide a range of possible future fuel and environmental compliance costs.

Q. Please discuss FPL's 2014 load forecast and how it compares to FPL's 2013 load forecast.

A. Exhibit SRS-4 presents the 2013 and 2014 Summer peak load forecasts. As shown in Column (3) of this exhibit, the 2014 forecast of Summer peak load is generally lower than the 2013 forecast.

In addition, Exhibit SRS-4 also provides a projection of the annual and cumulative growth in Summer peak loads associated with the 2014 peak load forecast. As shown in column (5) of this exhibit, FPL projects a cumulative growth in Summer peak load of approximately 3,139 MW by 2022 which increases to 5,109 MW by the year 2025.

Q. Based on this projected growth in Summer peak load, what is FPL's projected need for new resources?

A. FPL's projected need for new resources, assuming that the resource need is met by new generating capacity, is presented in Exhibit SRS-5. This projection assumes that FPL implements DSM at the level which FPL has proposed as its new DSM Goals for the years 2015 through 2024 in Docket No. 130199–EI. This exhibit shows that, without the incremental capacity from Turkey Point 6 & 7 and with no other generating additions from 2022-on, FPL has a need for new resources starting in 2022 and this need increases every year thereafter. The projected resource need in 2022 is 476 MW of new generating capacity and this projected resource need increases to 2,930 MW by 2025. In addition, as shown in Column (11) of this exhibit, FPL's minimum 10% generation-only reserve margin criterion would also not be met for each year beginning in the year 2022 assuming that neither Turkey Point 6 & 7, nor any other generating addition, was made beginning in the year 2022.

Q. What other assumptions changed from the 2013 analyses to the 2014 analyses?

A. Exhibit SRS-6 presents the 2013 and 2014 projections for 10 other assumptions that were utilized in the feasibility analyses of the Turkey Point 6 & 7 project.

Q. Please discuss the first five assumptions.

A. These five assumptions are:

1) the number of environmental compliance cost scenarios;
2) financial/economic assumptions;
3) the projected capital cost of competing CC capacity;
4) the projected heat rate of competing CC capacity; and,
5) the projected cost of firm gas transportation.

In regard to the number of environmental compliance cost scenarios utilized in FPL's 2013 feasibility analyses, FPL is again using three scenarios in its 2014 resource planning work: Env I (representing low CO_2 compliance costs), Env II (representing medium CO_2 compliance costs), and Env III (representing high CO_2 compliance costs).

FPL's financial/economic assumptions used in the 2014 feasibility analyses have changed only in regard to the cost of debt and the discount rate from those used in the 2013 feasibility analyses. The financial/economic assumptions include the following: return on equity (ROE) is 10.5%, the allowed cost of debt is 5.14%, the debt-to-equity ratio is 40.38%/59.62%, and the associated discount rate is 7.54%.

The remaining three assumptions involve the costs of the competing new CC capacity used in the feasibility analyses. FPL's current projected (generator only) capital cost of CC capacity is $883/kW in 2022$. The current projected heat rate of this CC capacity, 6,334 BTU/kWh, is unchanged. The projected firm gas transportation cost has changed. Using the projected firm gas transportation cost for the year 2023 as an example, the value has decreased from $2.23/mmBTU to $1.20/mmBTU.

Q. Please discuss the remaining five assumptions.

A. These five assumptions are:

6) assumed in-service dates for Turkey Point 6 & 7;

7) assumed operating lives of Turkey Point 6 & 7;

8) non-binding capital cost estimate for the new nuclear units;

9) previously spent capital costs that are excluded from the 2014 feasibility analyses; and,

10) the cumulative annual capital expenditure percentages for Turkey Point 6 & 7.

The first of these five assumptions, the in-service dates of Turkey Point 6 & 7 utilized in the 2014 feasibility analyses are unchanged: 2022 & 2023. FPL Witness Scroggs' direct testimony addresses the in-service dates for Turkey Point 6 & 7.

The second of these assumptions is the assumed operating lives of the two new nuclear units. In its 2014 feasibility analyses, FPL is using two operating life assumptions: a 40-year operating life and a 60-year operating life. The assumption of a 40-year operating life is consistent with the operating life assumption used in prior feasibility analyses. FPL believes this is an increasingly conservative assumption.

Two of FPL's four existing nuclear units, Turkey Point 3 & 4, have now been operating for more than 40 years. Furthermore, all four of FPL's nuclear units have received a license extension from the Nuclear Regulatory Commission (NRC) enabling each unit to operate for a total of 60 years. In addition, FPL's parent company, NextEra Energy (NEE), owns and operates two other nuclear units, Point Beach 1 & 2, that have operated for more than 40 years. These two nuclear units, plus a third nuclear unit owned and operated by NEE (Duane Arnold), have also been granted a license extension from the NRC enabling each unit to operate for a total of 60 years. Therefore, FPL believes that a 40-year operating life assumption for Turkey Point 6 & 7 is conservative and is, therefore, also using an assumption of a 60-year operating life in the feasibility analyses.

The third of these assumptions is the non-binding cost estimate for constructing Turkey Point 6 & 7. The range of costs used in the 2014 feasibility analyses is \$3,750/kW to \$5,453/kW in 2014\$. This reflects an updating of the projected cost range. FPL Witness Scroggs' direct testimony also discusses the updating of this assumption.

The fourth of these assumptions is the previously spent capital costs that are excluded in the 2014 feasibility analysis. In order to account for "sunk" capital costs for the Turkey Point 6 & 7 project, FPL is excluding approximately $228 million of sunk costs that have already been spent through December 31, 2013. This represents an increase of approximately $36 million compared to the approximately $192 million sunk cost value utilized in FPL's 2013 feasibility analyses. FPL Witness Grant-Keene provides the sunk cost value of the Turkey Point 6 & 7 project in her direct testimony.

The fifth assumption is the cumulative annual capital expenditure percentages for the construction of Turkey Point 6 & 7. The annual expenditure percentage values used in the 2014 feasibility analyses are largely unchanged from the values used in the 2013 feasibility analyses.

Q. **It is clear that a number of changes in assumptions were made between those used in the 2013 feasibility analyses and those used in the 2014 feasibility analyses. Were all of these assumption changes favorable to the projected economics of the Turkey Point 6 & 7 project?**

A. No. Assumption changes are made on a regular basis by FPL in order to utilize the best and most current information available in its resource planning analyses. Typically, updates to some assumptions are favorable, and changes to other assumptions are unfavorable, for any specific resource option or project.

This was indeed the case for the Turkey Point 6 & 7 project in regard to the changes in assumptions from those used in the 2013 feasibility analyses to those used in the 2014 feasibility analyses. For the Turkey Point 6 & 7 project, some updated assumptions, such as the lower natural gas cost forecasts, are unfavorable for the project (although favorable overall for FPL's customers).

All of FPL's updated assumptions, whether favorable or unfavorable for the Turkey Point 6 & 7 project, were included in FPL's 2014 feasibility analyses of the project.

Q. If the assumed 2022 and 2023 in-service dates are impacted by a longer than anticipated licensing phase, does the use of these in-service dates still allow a meaningful feasibility analysis of Turkey Point 6 & 7?

A. Yes. The feasibility analysis compares the relative economics of new nuclear capacity versus the best non-nuclear generation alternative (gas-fired CC generation). As long as a consistent set of assumptions, including in-service dates, is used to compare the competing resource options, the feasibility analysis will provide meaningful results.

Furthermore, the use of 2022 and 2023 in-service dates results in a conservative projection of the economics of Turkey Point 6 & 7 in regard to forecasted fuel commodity costs that would be saved by the two nuclear units in comparison to later in-service dates. For example, the forecasted Medium Fuel Cost of natural gas in the year 2022 is \$6.62/mmBTU. The projected fuel cost savings from the first year of operation of the first of the two new nuclear units, Turkey Point 6, for any scenario in the feasibility analysis using the Medium Fuel Cost forecast is based on this forecasted gas cost. If the in-service date for Turkey Point 6 is later than 2022, the projected fuel cost savings from the first year of operation of Turkey Point 6 would be based on a higher gas cost than \$6.62/mmBTU. For example, the forecasted Medium Fuel Cost for natural gas is \$6.93/mmBTU for 2023, \$7.34/mmBTU for 2024, and the forecasted cost will be higher in each subsequent year. Thus the projected fuel cost savings for the first year of operation, and for each subsequent year of operation, of the new nuclear capacity would be considerably increased if the in-service dates for Turkey Point 6 & 7 were assumed to be later than that assumed in the feasibility analyses.

III. Analysis of the Turkey Point 6 & 7 Project

Q. What resource plans were used to perform the 2014 feasibility analyses of Turkey Point 6 & 7?

A. The resource plans that were utilized in the 2014 feasibility analyses of Turkey Point 6 & 7 are presented in Exhibit SRS-7. One resource plan with Turkey Point 6 & 7 and another resource plan without Turkey Point 6 & 7 are presented in this exhibit. As shown in this exhibit, the two resource plans are identical through the year 2021. The resource plans differ starting in 2022. The Resource Plan with Turkey Point 6 & 7 adds the two 1,100 MW nuclear units, one in 2022 and one in 2023. The Resource Plan without Turkey Point 6 & 7 adds two 1,269 MW CC units, one in 2022 and one in 2024. Both resource plans then add the necessary amount of capacity through the rest of the analysis periods. The timing of these later capacity additions varies between the two resource plans.

Q. **What were the results of the 2014 feasibility analyses for Turkey Point 6 & 7?**

A. The results of the 2014 feasibility analyses for Turkey Point 6 & 7 are presented in Exhibits SRS-8 and SRS-9. Exhibit SRS-8 presents the results for Case # 1 that assumes a 40-year operating life. Exhibit SRS-9 presents the results for Case # 2 that assumes a 60-year operating life. In both of these two cases, all 7 scenarios of fuel cost forecasts and environmental compliance cost forecasts are analyzed.

The calculated breakeven nuclear capital costs in overnight construction costs in terms of $/kW in 2014$ are presented in Column (6) of these exhibits. The results in Column (6), when compared to FPL's non-binding estimated range of capital costs in 2014$ of $3,750/kW to $5,453/kW, show that the projected breakeven capital costs for Turkey Point 6 & 7 are above this range in 2 of 7 scenarios in Exhibit SRS-8 (Case # 1) and in 5 of 7 in Exhibit SRS-9 (Case #

2). Thus Turkey Point 6 & 7 is projected to clearly be the economic choice in 7, or half, of the 14 scenarios.

These exhibits also show that of the remaining 7 scenarios, the results for 6 of these scenarios are that the projected breakeven costs for Turkey Point 6 & 7 are within the non-binding capital cost estimate range. In the single scenario in which the projected breakeven capital costs for Turkey Point 6 & 7 are below the range of non-binding capital cost estimates, the combination of assumptions included in this scenario are: (i) low natural gas costs each year through the year 2063; (ii) low environmental compliance costs each year through the year 2063; and (iii) the lower of the two operating life assumptions (40 years).

Also, as evidenced by the CPVRR values for this single scenario, compared to the CPVRR values for all other scenarios, FPL's customers would still benefit greatly if these assumed low costs for natural gas and/or environmental compliance were to materialize. For example, using the projected CPVRR costs for the Resource Plan with Turkey Point 6 & 7, the projected CPVRR costs under the Case # 1 Medium Fuel Cost/Env II scenario are $142,065 million, but are projected to be significantly lower, $116,223 million, under the Low Fuel Cost/Env I scenario. Therefore, although the economics for the Turkey Point 6 & 7 project are diminished under a scenario of lower fuel and environmental compliance costs (i.e., Low Fuel Cost/Env I), FPL's customers are still projected to benefit significantly under such a scenario by $25,843 million CPVRR.

Q. In addition to the results of these economic analyses, did FPL's 2014 feasibility analyses identify any additional advantages for FPL's customers that are projected to be derived from the Turkey Point 6 & 7 project?

A. Yes. I will discuss three other advantages to FPL's customers that are projected to result from the Turkey Point 6 & 7 project:

1) system fuel savings;
2) system fuel diversity; and,
3) system CO_2 emission reductions.

These advantages for the Turkey Point 6 & 7 project that will be discussed in the remainder of my testimony will use the results from the 2014 feasibility analyses for the Case # 1: Medium Fuel Cost, Env II scenario. Comparable results also occur using the same fuel cost and environmental compliance cost forecast scenario in the Case # 2 analyses.

In regard to system fuel savings, the CPVRR values for the system fuel savings for each scenario of fuel cost and environmental compliance cost is accounted for in the respective total CPVRR savings number for that scenario. As shown in Exhibit SRS-8, these CPVRR savings values are then translated into breakeven costs. Consequently, the system fuel savings have already been accounted for in the breakeven cost values. However, it is informative to also look at the annual nominal fuel savings projections for Turkey Point 6 & 7.

In 2024, the first year in which both of the new nuclear units are in service for a full year, Turkey Point 6 & 7 are projected to save FPL's customers approximately $644 million (nominal) in fuel costs for that year.

Q. What are the projected fuel savings over the operating life of the Turkey Point 6 & 7 units and how do those projections compare with FPL's current total system annual fuel cost?

A. The total fuel savings for FPL's customers is projected to be approximately $64 billion (nominal). FPL's 2013 annual total system fuel cost was approximately $3.1 billion. Therefore, the projected fuel savings over the life of the Turkey Point 6 & 7 units is equivalent to serving FPL's more than 4.6 million customer accounts (representing approximately 9 million people) for approximately 21 years at zero fuel costs for FPL's customers based on last year's annual fuel costs.

Q. Please discuss the projected fuel diversity and CO_2 emission reduction benefits for Turkey Point 6 & 7.

A. Regarding system fuel diversity, in 2024 the relative percentages of the total energy supplied by FPL that is projected to be generated by natural gas and nuclear, without Turkey Point 6 & 7, are approximately 72% and 21%, respectively. With Turkey Point 6 & 7, these projected percentages change to approximately 58% for natural gas and 35% for nuclear. Thus FPL is projected to be far less reliant on natural gas, and more reliant upon nuclear energy, by approximately 14% each.

These percentage changes in system fuel use for a system the size of FPL's are significant. This can be demonstrated by looking at the projected amount of energy that will be supplied by the two new nuclear units in 2024. That amount of energy is projected to be approximately 17.7 million MWh. The current forecasted average annual energy use per residential customer in 2024 is 13,314 kWh. Therefore, the projected output from Turkey Point 6 & 7 in 2024 will serve the equivalent of the total annual electrical usage of approximately 1,329,000 residential customers in that year.

The improvement in system fuel diversity from Turkey Point 6 & 7 can also be demonstrated, for illustrative purposes, by looking at the amount of natural gas or oil that would have been needed to produce this same number of approximately 17.7 million MWh in 2024 if that energy had been produced by a conventional steam generating unit with a heat rate of 10,000 BTU/kWh. In such a case, Turkey Point 6 & 7 can be thought of as saving approximately 177,000,000 mmBTU of natural gas (if all of this energy had been produced by natural gas), or approximately 27,600,000 barrels of oil (if all of this energy had been produced by oil), in 2024.

Q. In regard to fuel diversity, is there another aspect of FPL's projected fuel mix that should be kept in mind when considering the addition of Turkey Point 6 & 7.

A. Yes. FPL's fuel mix currently consists of coal-based energy contributions from several sources including FPL's partial ownership of coal units at the Scherer and St. John's sites, plus coal-based power purchase agreements (PPAs) with Cedar Bay, Indiantown, and St. John's. A substantial amount of this coal-based capacity and energy is projected to end between 2019 and 2025.

The St. John's 375 MW PPA is currently projected to effectively end around April 2019 due to Internal Revenue Service regulations on the cumulative amount of energy that FPL can receive under this agreement. In addition, the current agreements with Cedar Bay (250 MW) and Indiantown (330 MW) are scheduled to terminate in 2024 and 2025, respectively. It is unknown if future agreements with these two facilities could be reached, particularly given the current economics of coal versus natural gas and the possibility of new environmental regulations that will be unfavorable to coal energy production. For the same reasons, it is unlikely that any new coal-fired generation will be added – by anyone – in Florida for the foreseeable future.

The projected loss of this coal-based capacity is accounted for in the previously mentioned gas versus nuclear fuel mix percentage values. The important point regarding gas and coal usage is that the contribution of coal generation will decline; not that projected gas usage is increasing while coal usage remains constant. Instead, gas usage is projected to increase, in part, because the usage of one non-gas fuel - coal - is expected to substantially decline in the near future. The role of additional nuclear energy in regard to fuel diversity thus becomes even more important than may be apparent in the gas vs. nuclear percentage values previously discussed when one recognizes that coal usage will actually be significantly declining in absolute terms.

Q. What is the projected impact of Turkey Point 6 & 7 on FPL's system CO_2 emissions?

A. In regard to system CO_2 emissions, Turkey Point 6 & 7 are projected to result in a cumulative reduction over the expected life of the two units of approximately 267 million tons of CO_2. This will be a significant reduction in CO_2 emissions, representing approximately 654% of the total CO_2 emissions from all FPL-owned generating units in 2013 (which was approximately 41 million tons). Stated another way, this projected cumulative CO_2 emission reduction from Turkey Point 6 & 7 is the equivalent of operating FPL's very large system of more than 24,000 MW of generation for approximately 78 months, or approximately 6.5 years, with zero CO_2 emissions.

Q. In regard to the projected fuel cost savings and emission reductions discussed above, does Turkey Point 6 & 7 provide other benefits for FPL's customers?

A. Yes. Nuclear power provides an important hedge for customers against the potential for future natural gas prices to be higher than forecasted and the potential for costly environmental (especially CO_2) regulations. Because the price of nuclear fuel is unrelated to fossil fuel prices, and because it produces no SO_2, NO_x, CO_2, etc., emissions in producing electricity, it is a superb hedge against higher fossil fuel costs and environmental compliance costs.

Q. In regard to potential savings for FPL's customers, are the hedge benefits of Turkey Point 6 & 7 still significant in light of lower forecasted fuel costs in 2014 compared to 2013 and no change in forecasted environmental compliance costs?

A. Yes. The potential hedge benefits of Turkey Point 6 & 7 remain very large. The new nuclear capacity is projected to provide FPL's customers with the greatest benefit in those future scenarios where customers need the most assistance: scenarios with high future costs for natural gas and environmental compliance. In the 2014 feasibility analyses, the potential hedge benefits are projected to be up to approximately $60 billion CPVRR assuming a 40-year operating life of the units, and up to approximately $75 billion CPVRR assuming a 60-year operation life.

Q. Please explain.

A. Exhibit SRS-10 illustrates this using the 40-year operating life assumption for Turkey Point 6 & 7. Page 1 of 2 of this exhibit focuses on how much projected CPVRR costs for resource plans have changed from 2013 to 2014. The projected CPVRR costs for the Resource Plan without Turkey Point

6 & 7 from FPL's 2013 feasibility analyses and from this year's feasibility analyses are utilized in this comparison. CPVRR costs for all 7 scenarios of fuel costs and environmental costs are presented. The order in which these scenarios are presented has been changed so that the projected CPVRR costs appear roughly in order from highest cost at the top of the exhibit to lowest cost at the bottom of the exhibit.

The projected CPVRR costs from the 2013 feasibility analyses and from the 2014 feasibility analyses are presented in Columns (3) and (4), respectively. Column (5) then presents the amount by which the projected CPVRR cost of the Resource Plan without Turkey Point has changed from the 2013 feasibility analysis to the 2014 feasibility analysis. The amount by which the projected CPVRR costs have changed is substantial, ranging from approximately $10.4 billion CPVRR to $13.5 billion CPVRR. Although, as previously discussed, a number of assumptions have changed including FPL's load forecast, resource plan, etc., much of the substantial change in CPVRR costs is due to lower forecasted fuel costs.

Page 2 of 2 of the exhibit focuses solely on the 2014 feasibility analysis results and how much variation exists in the projected CPVRR costs between the 7 scenarios. Column (3) on page 2 of 2 again presents the projected CPVRR costs for each of the 7 scenarios from this year's feasibility analyses. Column (4) then presents the projected CPVRR cost differences for each scenario compared to the lowest cost scenario (Low Fuel Cost, Env I) shown on the bottom row of the exhibit. The lowest cost scenario was chosen as the point of comparison because it is the scenario for which the projected breakeven capital cost for Turkey Point 6 & 7 (shown in Column (8)) is the lowest; i.e., the scenario for which the new nuclear units are projected to have the least value.

The differential values presented in Column (4) show that significant projected cost differences between the remaining 6 scenarios and the lowest cost scenario remain even with the lower 2014 forecasted fuel costs. These projected cost differences begin at approximately $21 billion CPVRR and range up to approximately $60 billion CPVRR. Column (5) also presents these differences in terms of percentage changes from the lowest cost scenario and the percentage differences range from 17% to 48%.

Column (6) offers an FPL customer perspective regarding the projected costs and electric rates associated with each scenario. The best scenario in this regard for FPL's customers is that shown on the bottom row of the exhibit. Every other scenario is projected to have higher costs and higher electric rates, thus resulting in a worsening future scenario for FPL's customers in regard to costs and electric rates that are largely driven by higher forecasted fuel costs.

Column (7) presents the relative level of hedge benefits of Turkey Point 6 & 7 for the various scenarios. The hedge benefits of the two nuclear units are highest when examining the top row of the exhibit in which projected fuel costs (and environmental compliance costs) are the highest. The hedge benefits of Turkey Point 6 & 7 are at their lowest in the bottom row in which projected fuel costs (and environmental compliance costs) are the lowest. However, in the last row, FPL's customers are already projected to have costs lower than in any other scenario by approximately $21 billion CPVRR to $60 billion CPVRR.

In summary, although current fuel cost forecasts are lower than those used in the 2013 feasibility analyses and there has been no change in forecasted environmental compliance costs, Turkey Point 6 & 7 continue to offer enormous hedge benefits for FPL's customers in regard to potential long-term cost savings.

Q. Does Turkey Point 6 & 7 provide other hedge benefits?

A. Yes. There are potential avoided cost or hedge benefits that will be provided by Turkey Point 6 & 7 if a "nuclear neutral" Renewable Portfolio Standard (RPS) or Clean Energy Standard (CES) mandate is imposed in the future. In such a circumstance the 2,200 MW of Turkey Point's nuclear capacity will reduce the need for, and the cost of, a large amount of renewable generation that would otherwise need to be built to meet the mandate. Such cost savings would likely be significant. This mandate has the possibility to occur in the future with or without the establishment of CO_2 compliance costs.

Q. Will Turkey Point 6 & 7 also defer/avoid costs of new transmission facilities that would otherwise be needed to import power into the Southeastern Florida region?

A. Yes. The addition of 2,200 MW of capacity from Turkey Point 6 & 7 in Miami-Dade County is projected to achieve significant transmission cost savings by avoiding the construction of transmission facilities that would otherwise need to be built to import power from outside the Southeastern Florida region (Miami-Dade and Broward Counties) into that region. These savings are currently projected to be approximately $2 billion CPVRR. This savings value is accounted for in FPL's 2014 feasibility analyses of the Turkey Point 6 & 7 project as an additional cost incurred in the Without Turkey Point 6 & 7 resource plans.

Q. In regard to exhibits that accompany other FPL witnesses' testimonies in this docket, was any of the information presented in those exhibits provided by you?

A. Yes. The projected capital cost savings for FPL's customers in regard to the EPU project that results from Florida's Nuclear Cost Recovery process that is presented in FPL's witness Jones' Exhibit TOJ-6, page 2 of 2, is based on an analysis that was performed under my supervision. The result of that analysis is that FPL's customers are projected to save approximately $300 million (nominal), or $81 million (CPVRR), due to Florida's Nuclear Cost Recovery process in regard to the EPU project.

Q. Please briefly explain how the Nuclear Cost Recovery process saves money for FPL's customers.

A. The Nuclear Cost Recovery process allows for annual recovery of interest costs incurred through construction, rather than long-term recovery under the normal Allowance for Funds Used During Construction (AFUDC) approach. This enables FPL's customers to avoid paying significant compounded interest charges they would otherwise incur.

Q. Was a similar analysis performed regarding the projected capital cost savings for FPL's customers from Florida's Nuclear Cost Recovery process in regard to Turkey Point 6 & 7?

A. Yes. Similar analyses of the projected capital cost savings for FPL's customers in regard to Turkey Point 6 & 7 that results from Florida's Nuclear Cost Recovery process were performed under my supervision. The results of one of these analyses, assuming the high-end of the non-binding capital cost range and a 40-year operating life, are presented in FPL witness Scroggs' Exhibit SDS-10, page 1 of 1. The result of this analysis is that Florida's Nuclear Cost Recovery process is projected to save FPL's customers approximately $10.4 billion (nominal), or $293 million (CPVRR), in capital cost savings. Another analysis that was performed, assuming the low-end of the non-binding capital cost estimate range, and a 40-year operating life for the units, resulted in a projection that Florida's Nuclear Cost Recovery process will save FPL's customers approximately $7.3 billion (nominal), or $249 (CPVRR), in capital cost savings.

Q. What conclusions do you draw from the results of the 2014 feasibility analyses of Turkey Point 6 & 7?

A. In regard to these economic feasibility analyses, the Turkey Point 6 & 7 project is projected to be the economic choice in at least half of the 14 scenarios analyzed. In the single scenario in which the two new nuclear units are not projected to be economic, that scenario assumes low natural gas costs each year through 2063, low environmental compliance costs each year through 2063, and the lower of the assumed operating lives for the two units. Under the assumptions utilized in this one particular scenario, FPL's customers are still projected to have significantly lower CPVRR costs than in all other scenarios. Therefore, Turkey Point 6 & 7 is projected to not only be the economic choice in at least half of the 14 cases analyzed, it will also be beneficial to FPL's customers in terms of increased system fuel diversity, reduced system emissions, and as a significant hedge against higher fuel and environmental compliance costs.

Thus, the results of the 2014 feasibility analyses strongly support the feasibility of continuing the Turkey Point 6 & 7 project.

Q. Does this conclude your testimony?

A. Yes.

(Transcript continues in sequence in Volume 2.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 5th day of August, 2014.

Linda Boles

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