BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110009-EI

In the Matter of:

NUCLEAR COST RECOVERY CLAUSE.
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VOLUME 6

Pages 809 through 983

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER LISA POLAK EDGAR COMMISSIONER RONALD A. BRISÉ COMMISSIONER EDUARDO E. BALBIS COMMISSIONER JULIE I. BROWN
DATE:	Wednesday, August 10, 2011
TIME:	Commenced at 5:10 p.m. Concluded at 7:04 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6734
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
76 through 87		872
88 through 99		980

P R O C E E D I N G S

(Transcript continues in sequence from Volume 5.)

MR. YOUNG: Mr. Chairman, staff would note that the next witness' direct and rebuttal will be taken up at this time.

MR. ANDERSON: Mr. Ross will be presenting our next witness, Mr. Derrickson.

MR. ROSS: Mr. Chairman, I don't believe Mr. Derrickson has been sworn.

(Witness sworn.)

CHAIRMAN GRAHAM: Thank you, sir.

WILLIAM B. DERRICKSON

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

DIRECT EXAMINATION

BY MR. ROSS:

Q. Would you please state your name and business address?

A. My name is William B. Derrickson. My business address is 1813 Eagles Glen Cove, Austin, Texas 78732.

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

A. I am employed by WPD Associates, and I'm the it President of the company.

Q. Have you prepared and caused to be filed 31 pages of Prefiled Direct Testimony in this proceeding on March 1st, 2011?

A. Yes.

Q. Do you have any changes or revisions to your prefiled direct testimony?

A. No.

Q. If I asked you the same questions contained in your Prefiled Direct Testimony, would your answers be the same?

A. Yes.

MR. ROSS: Mr. Chairman, I ask that the Prefiled Direct Testimony of Mr. Derrickson be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert the Prefiled Direct Testimony of Mr. Derrickson into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WILLIAM B. DERRICKSON

DOCKET NO. 110009-EI

March 1, 2011

Section I: Background and Experience

Q. Please state your name and address.

A. My name is William B. Derrickson. My address is 1813 Eagles Glen Cove, Austin, Texas 78732.

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

A. I am the president of WPD Associates.

Q. Please describe WPD Associates.

A. WPD Associates is a small, private consulting company specializing in project management.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Electrical Engineering from the University of Delaware and completed the Program for Management Development at the Harvard

Business School. I also completed a number of other management-related courses, a complete list of which are included in my resume (Exhibit WBD-1).

I have been involved with the power and chemical industries for the past forty seven years, beginning in 1964 as an electrical maintenance engineer at the Indian River Power Plant in Delaware. I spent approximately two years with Hercules Incorporated designing and starting up instrumentation and control systems for chemical plants. I entered the nuclear power industry as an electrical startup engineer at Florida Power & Light Company's (FPL) Turkey Point nuclear power plant in 1970. I was appointed Startup Coordinator in 1971; Construction Supervisor for the St. Lucie Unit 1 project in 1973; Project General Manager for major retrofit projects at Turkey Point in 1975; and Project General Manager of the St. Lucie Unit 2 project in 1977. I was promoted to Director of Projects in 1983.

In 1984 I accepted the position of Senior Vice President of Nuclear Power for Public Service Company of New Hampshire, responsible for completing and operating the Seabrook Nuclear Power Plant.

Following completion of the Seabrook Plant in 1988, I joined Quadrex Corporation, a small specialty environmental company. In 1993 I left Quadrex and formed a consulting company to assist clients with the management of major projects. I have also served as an expert witness in a number of cases, the most significant of which are detailed in my resume.

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

A. I entered the nuclear power industry as an electrical startup engineer at the Turkey Point Plant in 1970, and was promoted to the position of Startup coordinator in 1971. As Startup Coordinator I was responsible for the testing of plant systems and components to verify their performance to the requirements of the final safety analysis report, and to turn the systems over to the plant operating department once performance was demonstrated.

In 1973 I was appointed Construction Supervisor for the St. Lucie Unit 1 project. In that position I was FPL's site representative to oversee all construction activities. We established oversight in the areas of planning and scheduling, quality control, testing, and productivity to assure that the site activities were performed as efficiently as reasonably possible and that the plant was being constructed in accordance with applicable codes and standards. In 1975 I was appointed Assistant Project General Manager for the St. Lucie Unit 1 project with the mission of completing the project and commencing commercial operation.

In January 1977 I was appointed Project General Manager for the St. Lucie Unit 2 project. At that time FPL was performing an alternate site study mandated by the Nuclear Regulatory Commission (NRC) as well as working on plant design. The late 1970s and early 1980s were particularly challenging and dynamic times in the nuclear industry, following the formation of the NRC in 1974. As a result, numerous new regulatory requirements were continually being issued. These were, among others, in the areas of security, pipe supports, concrete anchors, fire protection, seismic conditions, and other requirements as a result of the accident at Three Mile Island (TMI) Unit 2 in 1979. The continuously emerging regulatory requirements made it very difficult for the engineers to complete the plant design. However, with the support of FPL senior management and a qualified and dedicated project team, the plant commenced commercial operation only two months behind the original 72-month schedule. This was accomplished despite having to address nearly a thousand new regulations and recover from extensive damage caused to the plant as a result of hurricane David in September 1979.

More on the St. Lucie Unit 2 project is explained in a paper presented at a 1982 meeting of the Project Management Institute (PMI) (Exhibit WBD-2). In the paper, Chart 22 lists 12 "Ingredients for a Successful Project" identified by the St. Lucie 2 project team in 1982, which, as discussed below, I have used in my evaluation of FPL's performance on the Extended Power Uprate (EPU) Project in 2010. Another paper (Exhibit WBD-3) describes the 12 "Ingredients" in more detail. The St. Lucie Unit 2 success was also recognized by Engineering News Record Magazine with an article entitled "Nuclear Construction-Doing it Right" featured in its April 23, 1983 edition (Exhibit WBD-4).

The 12 ingredients for a successful project were identified by the St. Lucie 2 project team in 1982 as a result of a request from the NRC as to how FPL was able to achieve its schedule objectives while the rest of the nuclear power industry was struggling. Since 1982 organizations such as PMI, the International Organization for Standardization and the International Atomic Energy Agency have subsequently produced project management guidelines that now also have memorialized either identical or similar criteria for managing projects.

In 1984 I joined Public Service Company of New Hampshire as Senior Vice President of Nuclear Energy, responsible for completing and operating the Seabrook Nuclear Plant. When I arrived in New Hampshire in 1984, the project was plagued with virtually every nuclear power plant construction problem I had ever experienced. There was a schedule slip annually with accompanying cost estimate increases. Project staff working on the project was located in Philadelphia, PA, Framingham, MA, Manchester, NH and Pittsburgh, PA as well as at the site, and there were over 10,000 people on the project. When I assumed responsibility for the project, I employed the 12 ingredients from the St. Lucie Unit 2 project. I reduced staff, moved virtually all project personnel to the site, brought on qualified management, and developed a realistic schedule and estimate. The plant was completed and fuel was loaded into the reactor in November 1986. After successfully completing and testing a utility developed emergency plan for New Hampshire, Maine and Massachusetts – a project in and of itself – the operating license was issued in January 1990.

I accepted another challenging assignment in 1986 as Nuclear Advisor to the Board of the Tennessee Valley Authority (TVA). TVA owned nine nuclear units: three Brown's Ferry units and two Sequoyah units, all of which were in operation; two units under construction at the Watts Bar site; and two which were partially constructed but with no ongoing activity at the Bellefonte site.

In 1985 a problem developed with welding at the Watts Bar plant and an independent company was retained to evaluate the situation. The reviewer appeared on Sixty Minutes and portrayed TVA in such an unfavorable light that its management voluntarily shut down the five operating units to inspect all welding. Upon completion of this welding inspection the NRC informed TVA that it had more work to do in order to get permission for the units to return to service. After a year of insufficient progress, I was retained as an Advisor to the TVA Board to facilitate getting the operating plants back on line and the two Watts Bar units completed. The situation I found at TVA was similar to what I had found at Seabrook. By 1987 there were approximately 16,000 people working on the seven units with little progress being made.

I advised the chairman of the TVA board that he needed to reduce the workforce by 10,000, and determine which unit was in the best shape and focus on that unit first. I then suggested scheduling work on the next units about eighteen months apart since NRC staff had limited resources to review TVA's documentation. That plan was generally accepted and successfully executed.

Q. **Please describe your experience with major nuclear plant retrofit projects.**

A. When St. Lucie Unit 1 was placed into commercial service in 1976, it was done with conditions to the NRC operating license. There were items which required completion at future milestones such as prior to power escalation, first refueling outage, or a specific future date. All such items were retrofitted into the completed plant. Most items were small on an individual basis, but were significant in total as the cost exceeded $20 million. Additionally, there were numerous regulatory changes that required plant modifications after the unit was completed. Examples of regulatory changes were new security requirements, post-TMI modifications memorialized in NUREG 0737, and the promulgation of new NRC fire protection regulations in 1981.

I was also responsible for two major retrofit and/or repair projects at Turkey Point. The first was the increase of storage capacity of the spent fuel pools at both units. The original design of the plant was for storage of one and one third reactor cores of fuel. Due to the lack of a facility to which to take spent fuel, it became necessary to increase the storage capacity of the pools to the maximum possible at that time. The pools in both units 3 and 4 were so increased. This work had to be accomplished so as not to impact the operation of either unit. It required moving fuel from one unit's pool to the other and back. The pools were also improved with heavier grade steel liners and leak detection.

I was also responsible for initiating and organizing the steam generator replacement project at Turkey Point. This project commenced in 1976 with the construction of a scale model of the reactor containment building. This enabled the job to be done on the model to determine all requirements for removal of structural steel, equipment, stairways etc. It also was helpful in determining how to get the steam generators in and out of the containment building without cutting the containment concrete. All six steam generators in both units were successfully replaced and remain in operation today.

I was also involved with the repair of the reactor core barrel which was damaged by the vibration of a thermal shield anchored on the core barrel at St. Lucie Unit 1. The project entailed cutting the thermal shield into strips that could be taken out through the fuel transfer tube, drilling crack arrestor holes in the core barrel, making nuclear qualified plugs to insert into the holes, and returning the reactor and refueling cavity to nuclear clean condition. It was later determined that the thermal shield was no longer necessary and replacement was not required. The entire project had to be done under water with remote tools due to the radioactivity in the reactor and its components. Many tools utilized to repair the core barrel were invented for the purpose of this project. The entire effort took fifty weeks. The plant was successfully returned to service and has been running well since.

Q. Have you testified previously in this case?

A. No

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring twelve (12) exhibits. They are:

Exhibit WBD-1:	My personal resume
Exhibit WBD-2:	"A Nuclear Plant Built on Schedule", a paper I wrote about how the St. Lucie Unit 2 project was managed
Exhibit WBD-3:	"Achieving Project Goals in Contrasting Environments-The Value of a Strong Management Philosophy", a paper written by me and George Bradshaw
Exhibit WBD-4:	"Nuclear Construction-Doing it Right", an article from ENR magazine
Exhibit WBD-5:	Chronology of Nuclear Power Event and Regulations
Exhibit WBD-6:	Cumulative Regulatory Changes (1968-1985)
Exhibit WBD-7:	The list of persons with whom I discussed the EPU Project
Exhibit WBD-8:	The list of documents reviewed
Exhibit WBD-9:	Photographs of the Turkey Point Plant
Exhibit WBD-10:	Photographs of the St. Lucie Plant

Exhibit WBD-11: PTN3R25 and 4R26 EPU Outage Details

Exhibit WBD-12: PSL EPU Outage Details

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

A. The purpose of my testimony is to opine on the prudence of EPU project management in 2010.

Q. Please summarize your testimony.

A. Based upon my review of relevant controls, procedures, and business documents, my interviews with various project personnel, and site visits, my conclusion is that FPL prudently managed the EPU project in 2010. Overall, FPL is employing the 11 applicable "Ingredients" for a successful project, which include (i) management commitment; (ii) financial resources; (iii) realistic and firm schedules; (iv) clear decision-making authority; (v) flexible project control tools; (vi) teamwork-individual commitment; (vii) engineering ahead of construction; (viii) early start-up involvement; (ix) organizational flexibility; (x) ongoing project critique; and (xi) owner leadership. These ingredients reflect industry-standard project management principles, and in my experience, are good indicators that a project is being prudently and reasonably managed. This conclusion is supported by the successful outage work that occurred in 2010.

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

A. Section 2 of my testimony provides a perspective on the evolution of the nuclear power industry which established the criteria under which all plants were licensed. I show why there are significant differences between plants and units such as Turkey

Point, St. Lucie Unit 1, and St. Lucie Unit 2. In this section I also show why projects such as the EPU Project pose challenges not found in the construction of new plants. Section 3 of this testimony details my review of FPL's management of the EPU project in 2010, which includes an evaluation of EPU management performance against the "Ingredients for a Successful Project." I also provide my review of and opinion on 2010 outage activities.

Section 2: Turkey Point, St. Lucie Unit 1 and St. Lucie Unit 2 in Perspective

Q. At a conceptual level, how are the Turkey Point and St. Lucie plants different?

A. As can be seen from the chronology attached as Exhibit WBD-5, the Turkey Point units were designed and constructed in a different regulatory era than the St. Lucie units. And, while the two St. Lucie units may look alike, there are significant differences between them as well. Exhibit WBD-5 lists the significant events in the evolution of the nuclear power industry and where the four FPL nuclear units fit into this timeline. Exhibit WBD-6 shows the cumulative number of regulatory changes issued between 1968 and 1985.

As can be seen from these exhibits, the Turkey Point units were designed and constructed at a time of few regulations, and regulated by the Atomic Energy Commission. For the first three years of the project, 10 CFR Appendix B, quality assurance requirements for nuclear power plants, did not exist. Thus, it was possible to build these units smaller, with shared facilities, adjacent to fossil units, and with a less stringent security system. Additionally, the Turkey Point units were completed with less than 200 regulations in effect. FPL was required to comply with just less than 400 to secure the St. Lucie Unit 1 operating license. While St. Lucie 2 was under construction an additional approximately 1000 regulations were promulgated with which FPL was required to comply.

Primarily as a result of the evolution of the regulatory and industry codes and standards, nuclear power plants changed with time. Each plant was required to be designed to the regulatory requirements in effect at the time it was licensed. Thus, St. Lucie Unit 1 incorporates more standards than Turkey Point, and St. Lucie Unit 2 incorporates more standards than St. Lucie Unit 1. For example, St. Lucie 2 was required to be designed to higher seismic criteria, to include full compliance with NRC fire protection regulations, and to have all post-TMI requirements incorporated before it could be licensed.

Some of the more prominent features that distinguish the Turkey Point plant from the St. Lucie units are that Turkey Point has a common control room as opposed to separate control rooms at St. Lucie; a shared reactor auxiliary building at Turkey Point as opposed to separate auxiliary buildings at St. Lucie; a single containment for each Turkey Point unit as opposed to concentric containments with an air space between the St. Lucie units; the Turkey Point building volume is about half the building volume of the St. Lucie units; Turkey Point is located next to fossil units, and, as licensed, the two Turkey Point units shared two emergency diesel generators, where at St. Lucie each unit has two emergency diesel generators.

Q. **How do the differences you described affect the management of the EPU?**

A. In addition to requiring new plants to be designed differently, many of the nearly 1,400 regulations issued between 1968 and 1985 as well as regulations promulgated since 1985 also affect the ongoing operation of the plants. One such set of regulations addresses plant security. Due to increasing concerns about threats such as terrorism, nuclear plant security has been escalated so that projects such as the EPU have to factor additional time into the schedule for processing personnel and material into the plant. This is especially onerous at Turkey Point where the nuclear units are adjacent to the fossil units, and the security barriers between the nuclear and fossil units make entry and exit extremely difficult. As a result, access to the secondary side of the nuclear units (turbine structure) is limited.

St. Lucie enjoys a much better arrangement. Even though the two St. Lucie units are close together, they are both nuclear units and are both inside one security boundary. Thus, access and logistics are considerably easier. This can be seen in the photographs included as Exhibit WBD-10. In Exhibit WBD-9, the photos show the access to the Turkey Point turbine building. As can be seen in these photos there is virtually no access from the north, via the fossil plant end of the turbine building due to the security fencing and razor wire. The photos in Exhibit WBD-9 also show the overall tight conditions at Turkey Point. At St. Lucie, however, as can be seen in Exhibit WBD-10, the photos show that considerably more room is available for storage and access. Thus, EPU modifications are significantly more difficult at Turkey Point.

Another result of the vintage and age of the Turkey Point units is that the plant was designed and built to codes and standards that are no longer applicable. As a result, when new work is planned, other work may be required to permit the licensing of the new work. The plant's age also is a factor. As equipment ages, and when modifications are attempted, additional work may surface. It is much like what happens when an older car is taken in for service, and while performing the service, the mechanic often discovers other things that need attention in order to properly complete the planned service.

The above issues require management to be flexible in planning, scheduling, and forecasting the cost for retrofit work. It is straightforward to estimate the cost of large components such as heat exchangers, pumps, motors, valves, transformers, and turbine parts, but labor, for example, is highly variable. When the emergent work is compounded with security requirements and the general logistics of working in an operating plant where there are pressurized lines and high voltage cables, productivity becomes a challenge. Safety is of the highest priority so productivity expectations often have to be adjusted to reflect the stringent safety conditions.

One of the largest challenges, however, is that much work can only be done during plant outages. For efficiency reasons, retrofit work is generally scheduled during refueling outages to avoid having the plant off line for any longer than necessary. Since refueling outages are generally 18 months apart, any perturbation in equipment delivery, engineering, licensing, or other critical activities can cause work to be significantly delayed. As a result, all stakeholders must be made aware of such possibilities and be prepared to plan for work-arounds or to reschedule the work until the next outage. Such a situation may be developing at Turkey Point due to the position of the NRC that it must address an issue, the proposed alternative source term (AST), before the uprate license application will be docketed. Consequently alternate scenarios are being discussed at FPL for rescheduling work priorities accordingly. These and many other challenges will likely occur, but they are merely management challenges. The important things are to do the work safely, minimize outage duration, and complete the project at the lowest reasonable cost and as close to the schedule objective as possible.

Q. Can you please describe the overall management challenges posed by a project such as the EPU?

A. There are at least eight salient challenges in doing major projects in operating nuclear power plants. They are:

a. Obtaining license modifications to a plant which may have been originally licensed to less stringent criteria;

b. Assuring that all work is done in a safe manner without compromise to the active steam, water, and power systems of the operating plant;

c. Working in very congested areas;

d. Coordinating work times and space with the plant operating staff;

e. Working in a security environment with double fences, multiple entry verifications, locked rooms and areas, armed security officers, and limited access points, all designed to keep the plant safe from security threats;

f. Dealing with emergent work as a result of the identification of consequential requirements from detailed engineering;

g. Accomplishing physical work within a pre-determined timeframe such as a refueling outage; and

h. The logistics of storing and moving material and locating facilities and equipment such as cranes, offices, warehouses and parking space for workers.

Q. Do cost and schedule projections often change for large projects such as the EPU?

A. Yes. There are a number of factors that affect both the cost and schedule of projects, and in most cases, the cost forecast appears to increase and the project requires more time than originally forecast. Large projects are virtually always complex, involve numerous regulatory and environmental approvals, include hundreds of drawings, thousands of components such as valves, pumps, motors, tanks, heat exchangers, and instruments, require the work of hundreds to thousands of people and take years to complete. For example, the original construction of St. Lucie Unit 2 required over 200,000 cubic yards of concrete, over 175,000 feet of pipe, over four million feet of electrical cable, over 425,000 feet of electrical conduit, and over 40,000 feet of cable tray. The quantities are the result of designing the plant to the then-current regulations, codes, and standards. The material must be specified, ordered, and once delivered to the plant site it must be properly handled and stored until needed. Final quantities cannot, however, be determined until the plant design is complete. In the case of St. Lucie 2, design continued until late into the project to address post-TMI and other NRC requirements.

While the EPU Project will not require large quantities of material such as would be required for a new plant, there a number of large components being replaced, such as the turbine rotors, the main generator rotor, selected feedwater heaters, moisture-separator re-heaters, main feedwater pumps, valves, and motors. This, as with a new plant, requires design, procurement, and proper storage on plant sites with limited space.

At the beginning of any project, adjusted historical data are all that is available to produce cost forecasts and develop schedules. Consequently, a contingency is added to the early estimates in an attempt to encompass unknown scope as well as other unknown factors. Similarly, allowances are made in early project schedules. In many cases, however, allowances can be insufficient for future unknowns, and, as a result, the project cost forecast appears to increase and the schedule becomes longer.

With respect to the EPU Project, new scope has emerged as Bechtel addresses and completes the detailed design work, and much of it is consequential. This will likely continue into the physical work (implementation) stage as well, especially at Turkey Point, since the plant is nearly 40 years old and was built to different standards. Additionally, since the EPU work is being done in operating plants, logistics add a dimension of difficulty and attendant cost which does not exist in new construction.

Section 3: Evaluation of FPL's Management of the EPU Project in 2010

Q. Have you formed an opinion with respect to FPL's management of the EPU project in 2010?

A. Yes.

Q. What is your opinion about FPL's management of the EPU project in 2010?

A. In my opinion, FPL is prudently managing the EPU project.

The generally accepted definition of "prudence" is acting "reasonably" based upon information available at the time decisions are made and actions are taken. In my experience, I have found that the 12 "Ingredients" for a successful project presented in Exhibit WBD-2 are useful tools to evaluate the reasonableness of project management's actions in various projects. These ingredients are also reflected in, and consistent with generally accepted project management standards, such as those included in the Project Management Institute's "A Guide to the Project Management Body of Knowledge." Therefore, I evaluated FPL's EPU project management by determining whether these 12 ingredients were being incorporated into the project. The FPL EPU project team is managing the project in a manner consistent with those "Ingredients" and generally accepted project management standards.

Q. On what information did you rely in forming your opinion?

A. To form my opinion on FPL's management of the EPU project, I did the following:

- I reviewed the Extended Power Uprate Project Instructions (EPPI) procedures that I considered most important to the management of the EPU Project and my review. The list of procedures, along with all other documents reviewed, is Exhibit WBD-8 to this testimony.
- I reviewed the documentation required by the procedures such as risk tables, trend reports, training records, estimates, schedules, presentations to an FPL Steering Committee, and Bechtel Metrics Reports.
- I reviewed the resumes of senior key management personnel.
- I interviewed 9 management personnel as shown in Exhibit WBD-7 to this testimony.

Q. Did you visit the Turkey Point and St. Lucie plant sites in 2010?

A. Yes. I visited both the St. Lucie and Turkey Point sites to review site facilities, speak with site management personnel, and tour plant locations where the EPU work will be performed. I was also briefed on the status of the project and plans for 2011.

Q. Do you have an opinion on the operation of the EPU site organizations?

A. Yes. Both sites appear to be well organized, are appropriately staffed, and personnel are located inside the plant security protected area. Roles and responsibilities appear to be clear and the organizations (FPL and contractors) appear to be functioning as a team. The laydown space is well organized, and there is great care in making sure that material is properly stored and handled.

Q. What is the basis of your opinion on FPL's prudence in 2010?

A. In general, I used the 12 "Ingredients for a Successful Project" found in Chart 22 of Exhibit WBD-2 as my approach for reviewing FPL's management of the EPU project. The following is a summary of my analysis of the EPU project management measured against each applicable ingredient.

1. Management Commitment

From my discussions with the FPL management, the involvement of senior management in steering committees, and the financial support for the EPU Project, it is clear that the EPU Project has full management support. I saw no indication of hesitation for FPL to do what is necessary to complete the EPU project as safely and as quickly as possible. At the same time, FPL management is also monitoring the project cost through trend, risk, and cost reports, and has commissioned independent reviews such as those conducted by Concentric Energy Advisors and myself. I believe that FPL's management is fully committed to the EPU project.

2. Financial Resources

From a review of the NextEra Energy, Inc. (NextEra) Forms 10K for 2009 and 10Q for quarter 3 of 2010 submitted to the U.S. Securities and Exchange Commission in

2010, it is clear that FPL, with the assistance provided through Florida's annual nuclear cost recovery mechanism, has a strong balance sheet, sufficient cash flow and borrowing power to finance the EPU project. FPL's financial strength has also been observed in the issuance of its debt securities. For example, in early 2009 FPL issued $500 million of first mortgage bonds, 5.96% series due April 1, 2039, which were rated "AA-". Based on the above it is clear that FPL has both the financial strength and borrowing capability to undertake projects such as the EPU project.

Based on the above it is clear that, within the current regulatory and cost recovery framework authorized by Florida law, NextEra has both the financial strength and borrowing capability to undertake projects such as the EPU project.

3. Realistic & Firm Schedule

A realistic schedule is prepared using the best information available at the time, while applying reasonable productivity rates and achievable material delivery times. That does not mean that there will not be variances in the schedule during the course of the project. As can be seen in Chart 11 in Exhibit WBD-2, even though the St. Lucie Unit 2 project was completed essentially on schedule, there were only a few weeks when the project was actually "on schedule." This was due to problems that occurred such as two labor stoppages during plant construction, the damage to the reactor auxiliary building caused by Hurricane David in 1979, the impact of the required implementation of new NRC fire protection requirements, and post-TMI requirements imposed by the NRC in 1980.

On retrofit projects such as the EPU project, however, schedule conditions are even more rigid than for new plants. This is because much work must be accomplished during scheduled plant outages. Thus, a small project challenge can result in months of delay in accomplishing the work if it cannot be completed until the next scheduled outage.

In reviewing the schedules for both Turkey Point and St. Lucie EPUs, the most significant schedule threat is the NRC approval of the License Amendment Requests (LAR). The schedules for completion of the uprates for each nuclear unit were based on historical information such as the delivery time for major components and the time required for the NRC to perform its review and issue license amendments. The NRC's actions are outside of FPL's control, and as a result the schedule could be affected if NRC approval is delayed. It is my opinion that the schedules developed by FPL for the EPU project were realistic and reasonable. However, events such as regulatory delays and consequential emergent work may require adjustments to the schedule.

4. Clear Decision Making Authority

Roles and responsibilities as well as the Juno Beach and site organizational structures on the EPU project are shown in procedure EPPI-140. Revision 9 of EPPI-140 clearly depicts the functioning of the EPU organization. EPPI-140, in conjunction with the full suite of EPPI procedures, clearly provide direction and guidance for essentially all required project functions.

I also reviewed output from the EPU organization, including schedules, EPU scope changes and forecast variances, a sample of training records, risk tables, Bechtel Metrics Reports, resumes of key personnel, and a sample of self-assessment records. Finally I discussed roles and responsibilities with several members of the EPU project team. From those discussions, I am satisfied that each member of the EPU staff was clear about their roles as well as the roles of upper management and peers.

Based on the above, it is my opinion that there is clear and appropriate decision making authority within the EPU Project.

5. Flexible Project Control Tools

When the original construction of St. Lucie Unit 2 began in 1976, the available technology was much less sophisticated than today. For example, there were no laptop computers, no internet, and little computer software was available for general use. Thus, performing computerized scheduling required a main-frame computer and was labor intensive. By the early 1980s, however, more computing technology began to emerge. This was in the form of personal computers and more software. As a result, as the St. Lucie Unit 2 project moved into the startup and punch list phases, we began to take advantage of this new technology. This was in the form of a focused startup schedule and a computerized punch list. We called this the project completion system to focus on the finishing of "punch list" work items required to complete the plant.

Today, virtually everything necessary can be done with one planning and scheduling software package such as Primavera. This is the software of choice for virtually all large projects. The selection of Primavera has afforded the EPU project the premier and most flexible project control tool available today. Instructions for developing, updating and modifying schedules are detailed in procedure EPPI-310, which also contains instructions for using the Primavera software.

The project control program for the EPU project also contains a suite of processes including:

- Interface and Variance Reporting, EPPI-150
- Time and Expense Reporting, EPPI-170
- Change Control, EPPI-300
- Forecast Variance and Trends, EPPI-301
- Cost Estimating, EPPI-320
- Risk Management, EPPI-340
- Engineering Risk Management, EPPI-345
- FPL Accrual Process, EPPI-370

I reviewed these processes as well as documents that have been created as outputs of these processes. All of the above processes are part of a package that permits management to determine its best estimate of the cost of work to be performed, identify and quantify risks, track trends and forecast resultant costs, control changes, and account for incurred costs. All of these constitute a solid project control system. Based on the comprehensive suite of project control processes employed for the EPU project and the use of Primavera software, the project control tools in use appear reasonable and meet the spirit of this "Ingredient".

6. Teamwork-Individual Commitment

Teamwork is something that I believe can best be determined by talking to project management and staff. To make such an assessment I specifically asked all persons with whom I had discussions if they thought there was teamwork on the EPU Project. Virtually everyone said there was. I also observed the interaction between the team members where possible, and there appears to be clear focus on the mission, and an understanding of the goals of the project. A team focused on the goal is an excellent ingredient for teamwork. Additionally, as recently as April 2010, FPL conducted a team building seminar. Among other things it focused on:

- Key objective is build/build upon relationships and advance issues;
- Recognize what's important to the other stakeholders;
- Identify your work behavior style, understand your strengths and weaknesses and comprehend the impact of that style on the team;
- Work on advancing issues from teambuilding interviews;
- Exchange feedback between groups on what is going well and what's missing, and how you can help;
- Engage in a discussion with our counterparts to build relations, improve communication and close gaps; and
- Develop and commit to Teamwork Behavior Absolutes.

Sessions such as this are important and reinforce FPL's commitment to foster a team relationship. Clearly, the EPU project is taking steps to assure that teamwork is in place, and from my observations it appears to be working.

7. Engineering Ahead of Construction

This ingredient was developed for a plant under construction where the owner or architect-engineer has a choice to begin construction with partially completed engineering or wait to begin construction until the design is more complete. While there are advantages of both alternatives, the latter permits a more predictable construction schedule. The St. Lucie 2 project team felt that by not beginning construction until the design was about 70% complete enabled the plant to be constructed essentially on schedule.

By operating license requirements called technical specifications, however, all modifications made to an operating nuclear power plant must be presented to an on-site review committee for approval. This is a process called a Plant Change and Modification (PCM). Thus, the design must be complete at that time. For the EPU project, the engineering required to get to the PCM is complex and in many cases requires a plant walk-down to verify the as-built condition of the plant. As a result, the engineering frequently is the critical path activity. For the EPU, each outage can be considered its own project, and all the design engineering is occurring before construction that occurs for that particular outage. As a result, FPL is in fact performing the necessary engineering before construction, despite the overlapping nature of the work on various units during various outages. In my opinion, this appears to be a reasonable way to complete necessary design engineering prior to construction, while at the same time completing the overall EPU project as soon as practicable.

8. Early Startup Involvement

Testing for the EPU project is delineated in procedure EPPI-445 issued on April 23, 2009. The issue date was approximately two years prior to EPU testing activity. As is stated in EPPI-445: The purpose of this procedure is to identify testing responsibilities for the EPU project and to delineate responsibility between FPL and the EPU engineering, procurement, and construction contractor. The testing responsibilities include preparing post modification test plans for modification packages, preparing new and/or revise existing test procedures for construction tests, pre-operational tests and start-up/power ascension tests; performing construction tests, post modification tests, and power ascension tests for the EPU projects. These activities are shared between FPL and the EPU contractor within the scope of their respective contract agreements. The procedure goes on to establish responsibilities, precautions, instructions and record requirements.

To implement this procedure a startup organization was established at both Turkey Point and St. Lucie in 2009. The organizations consist of a Manager supported by a staff of engineers, coordinators, and planners. Based on a review of procedure EPPI-445, the established organizational structure, discussions with the EPU site project managers, and FPL's responsibility under the requirements of its NRC operating licenses, it is my opinion that the startup requirements for the EPU project are well understood and have been implemented in a timely manner.

9. Organizational Flexibility

During the construction of St. Lucie Unit 2, the organization was continually re-aligned to emphasize the necessary leadership as the project passed from phase to phase. For example, at the beginning of the project, engineering and licensing were the primary activities. After the construction permit was received in June 1977, the project focus was the site construction organization. Later in the construction phase as the plant became nearly completed, the startup organization took the lead. A second licensing organization was formed to address post-TMI NRC regulatory requirements (see Chart 18 in Exhibit WBD-2). It is appropriate – indeed necessary – to be flexible and adjust the organization to the current needs of the project.

FPL made such an adjustment in 2009 as the project moved away from the conceptual phase into the production phase. More authority is now vested in the site manager, and functions such as engineering, licensing, and procurement were moved to the sites. All contractors now report to the site manager or his designee. As the projects move through construction and into startup and testing focus will again shift. As modifications are completed, staff will be reduced since early project functions such as engineering and licensing will no longer be required to the degree as they are now. Ultimately, as the projects wind down and records are completed, contractor staff will be reduced and FPL staff will be given new assignments. This is a typical cycle for all projects.

Contrary to an operating business or an operating power plant, from the day a project begins, all members of the project team begin to work themselves out of a job. However, most project people enjoy being part of a team that creates something. On a parcel of vacant land a power plant, a chemical plant, a skyscraper, or a major highway system takes shape. As that happens, most project people that I know feel like part of them becomes part of the project.

Based on my observation and interviews with the members of the EPU management team, I believe they are prepared for such future adjustments. As a result, it is my opinion that organizational flexibility is built into the EPU project philosophy.

10. Ongoing Critique of the Project

FPL has had the EPU project reviewed by several independent organizations, including the FPL quality assurance organization as required by 10 CFR 50 Appendix B, Concentric Energy Advisors, the FPL Internal Audit Department (Jefferson

Wells), the Florida Public Service Commission Audit Staff, and myself. FPL has also utilized outside resources such as High Bridge Associates, to perform an independent check on cost estimates for particular scopes of work. Additionally, procedure EPPI-380 requires formal self-assessments, and procedure EPPI-340 defines the EPU risk management program. While the latter two are not independent, they require a critical review and a formal evaluation of possible future risks to the project. As indicated above, I have reviewed self assessment documentation and risk tables. In total, these critiques represent a comprehensive critical view of the project.

Based on the above, the EPU project critiques are consistent with this "Ingredient".

11. Bethesda Office for Licensing

This Ingredient is not applicable to the EPU project. FPL established an office in Bethesda in 1981 to expedite the communication between FPL and the NRC during the NRC's review of the license application for St. Lucie Unit 2. Today, with the internet and the ability to electronically transfer files, such an office would not have the same benefit as in 1981.

12. Owner Takes the Lead

With both the St. Lucie and Turkey Point plants being NRC licensed operating facilities, FPL has the responsibility to protect the health and safety of the public as an overarching requirement in its NRC licenses. Also, the operation of each plant is governed by technical specifications approved by the NRC. This mandates that FPL be the lead on any work done in the plant. In the case of the EPU project, a separate organization was established to manage the integration of the engineering, procurement, construction, and testing. All contractors working on the EPU project report to the FPL site organization. The final approval to perform the work, however, resides with the Plant Manager of each plant. Accordingly, this "Ingredient" is clearly in place on the EPU project.

Q. Did you review any other aspects of the EPU project?

A. Yes. I reviewed FPL's vendor management, the execution of the EPU work during the one refueling outage in 2010, and preparations for two refueling outages in 2011.

Q. Please comment on FPL's EPC vendor management.

A. While there are many vendors employed on the EPU project, Bechtel has the largest scope for which there is the most risk remaining. For example, at St. Lucie the total forecast EPU cost was $916 million as of year-end 2010, of which about a third has been spent, another third involves work which has a well defined scope which includes FPL's in house cost and/or involves a fixed price contract such as major components resulting in low risk, and the remaining third is in Bechtel's engineering-procurement-construction (EPC) scope with the most risk. Thus management's attention should be and is focused on assuring that the work being performed by Bechtel meets the project's quality, cost and schedule objectives. The scope of work for both Bechtel and FPL is defined in a unique specification for each plant. Each specification describes in detail general information, project management, design engineering/licensing, construction/implementation, procurement, project controls, quality assurance/quality control, radiation protection, maintenance and operation of equipment, temporary services, and safety and security services. Each specification also provides references to applicable codes and standards and defines applicable technical terms.

In reviewing the specifications I found that they are clear and sufficiently detailed to reasonably assure that both Bechtel's and FPL's responsibilities are clearly defined. These specifications are also consistent with other such documents with which I am familiar.

I then reviewed the process employed for management of the Bechtel contract. It is very straight forward, provides good control and supports the "owner takes the lead" ingredient. Bechtel cannot perform any work without FPL's approval. The process begins with Bechtel submitting a scope form to FPL. FPL reviews the proposed work and negotiates the task. Once agreement is reached the task (job) is added to the EPU forecast and metrics. The new job is then added to the project control system and is tracked by Bechtel in its metrics report which is sent to FPL weekly. The Bechtel metrics report tracks each job by discipline earned hours and status. The Bechtel metrics report tracks and displays status, productivity, and cost performance. The approved job is also put into the Primavera scheduling system and is tracked by FPL. All jobs are tracked on an hourly basis during outages.

Based on my review, FPL is managing the Bechtel contract in a sound manner.

Q. Please comment on the execution of the fall 2010 outage.

A. EPU modifications were made at Turkey Point Unit 3 during a planned outage known as 3R25 which began on September 25, 2010.

Eleven EPU modifications were planned to be completed during the outage, but due to a variety of factors two modifications were deferred until the next refueling outage, 3R26, and the scope was reduced on four others. According to FPL the estimated cost for the modifications was $20.9 million and the actual cost was $18.7 million. Even though some cost reduction was due to deferrals and scope reduction, the overall performance appears to have been quite good.

More details on the Turkey Point outages can be found in Exhibit WBD-11.

Q. **Please comment on the preparations that were underway for the 2011 outages.**

A. Two outages are planned for 2011. As of year-end 2010, outage 2-20 was scheduled to begin on January 3, 2011 at St. Lucie 2 and outage 4R26 was scheduled to begin for Turkey Point 4 on March 19, 2011.

At Turkey Point, fourteen modifications are planned for which eleven PCM packages were issued prior to January 2011. The material required for the modifications is either on site or scheduled for delivery well in advance of the outage date. The EPU scope of work for outage 4R26 can be seen in Exhibit WBD-11.

I toured the Turkey Point plant on December 1, 2010 with the EPU Site Director and Senior Project Manager. On the tour I was shown the modifications planned for each unit, and which modifications were being planned for the March 2011 outage. From the tour and explanations of planned work, it was clear that the site EPU management is organized, the mission is clear, and the team is focused on meeting the EPU goals. Based on what I have seen, I believe the site organization has done an excellent job of planning and preparing for outage 4R26.

At St. Lucie, outage 2-20 was scheduled to begin on January 3, 2011 and included the EPU scope of work shown in Exhibit WBD-12. The outage was planned to be completed on March 9, 2011. This outage is significant in that it includes major modifications such as main transformer replacement, rewinding the main generator, main generator rotor replacement, low pressure turbine rotor replacement, and condensate pump replacement. It is estimated that an additional 20 megawatts will be realized from the modifications in outage 2-20 even without increasing reactor power, due to efficiencies gained. The forecast cost for the EPU modifications in outage 2-20 was $75.5 million.

I toured the St. Lucie plant with the EPU Site Director on November 30, 2010. During the tour I saw a very organized EPU operation with good use of the space to the south of the plant. Additionally, much preparatory work was ongoing in the plant in preparation for the January 3, 2011 commencement of the outage. Figure 11 shows photographs of the site laydown area as well as the organization of work areas in the plant. As can be seen the EPU project at St. Lucie is well organized and well prepared for the January 3, 2011 outage.

Q. What is your conclusion regarding FPL's EPU Project management?

A. Based upon my review of relevant controls, procedures, business documents, and my interviews with various project personnel, my conclusion is that FPL prudently managed the EPU project in 2010. Overall, FPL is employing the "Ingredients" for a successful project, which in my experience are good indicators that that project is being reasonably managed. This conclusion is supported by the successful outage work that occurred in 2010 and that appeared to be underway for 2011.

Q. Does this conclude your testimony?

A. Yes.

BY MR. ROSS:

Q. Mr. Derrickson, are you also sponsoring exhibits to your direct testimony?

A. Yes.

Q. Do those exhibits consist of documents labeled as WBD-1 through WBD-12?

A. Yes.

MR. ROSS: Mr. Chairman, I would note that Mr. Derrickson's exhibits are marked for identification as 76 through 87 on the staff's exhibit list.

CHAIRMAN GRAHAM: Yes, sir.

BY MR. ROSS:

Q. Mr. Derrickson, have you also prepared and caused to be file ten pages of Rebuttal Testimony in this proceeding on July 25th, 2011?

A. Yes.

Q. Do you have any changes or revisions to your rebuttal testimony?

A. No.

Q. If I asked you the same questions contained in your Prefiled Rebuttal Testimony, would your answers be the same?

A. Yes.

MR. ROSS: Mr. Chairman, I ask that the Prefiled Rebuttal Testimony of Mr. Derrickson be inserted into the record as though read.

CHAIRMAN GRAHAM: We will enter Mr. Derrickson's Prefiled Rebuttal Testimony into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF WILLIAM B. DERRICKSON

DOCKET NO. 110009-EI

JULY 25, 2011

Q. Please state your name and business address.

A. My name is William B. Derrickson. My business address is 1813 Eagles Glen Cove, Austin, Texas 78732.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

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

A. The purpose of my testimony is to address the work stoppages that occurred at Turkey Point Unit 3 and St. Lucie Unit 2 in 2010 and early 2011. I also briefly respond to Witness Jacobs's concerns related to the Company's 2007 decision to expedite the Extended Power Uprate (EPU) project.

Q. Please summarize your rebuttal testimony.

A. I reviewed the three work stoppages that occurred at Turkey Point and St. Lucie Unit 2 in late 2010 and early 2011. It is my opinion that FPL acted prudently by selecting quality contractors for the work, having proper procedures and supervision in place, and managing the contracts well. Nevertheless, it is a fact that on large construction projects such as the EPU, problems do happen, despite management having taken reasonable and prudent actions. In the above three situations, FPL management performed well by stopping work to protect human life and/or plant equipment, and determine the root cause of the problem. Very thorough analyses were done which identified the root cause of the problems and produced action plans to remedy each situation as well as prevent future occurrences. In all three cases FPL acted prudently prior to the work stoppage, then responded decisively and took responsible action.

Q. Please describe a "work stoppage" as that term is being used for purposes of the EPU project.

A. A work stoppage is the suspension of all work in a given physical area of a plant or a project. It can last from a few minutes to months depending on the situation. Typically work is halted to address personnel safety or to protect plant equipment, allow a root cause analysis of the situation to be addressed, take action to correct the root cause of the situation, and to develop a plan to prevent recurrence.

Q. Are work stoppages appropriate during the course of a project such as the EPU?

A. Work stoppages are not only appropriate, they are necessary to ensure safety and reemphasize training, and it is not out of the ordinary that such work stoppages would occur during a major construction project at a nuclear power plant. In fact, to not stop work when conditions exist that are either unsafe for workers or that could potentially damage plant equipment would be imprudent. As is described below, analyses of events which necessitated the work stoppages at both Turkey Point and St. Lucie Unit 2 led to procedure changes and additional training, both of which will reduce the probability of future similar events.

Q. Does the fact that a work stoppage occurred indicate FPL was imprudent in any respect?

A. No. FPL hired competent contractors, Siemens Energy, Inc. (Siemens) and Bechtel Power Corporation (Bechtel), both of whom have extensive experience and are recognized world-wide as experts in the energy field. Additionally, FPL has very specific contracts with its contractors containing requirements for safety, quality assurance, and reporting. FPL has EPU staff at each site to provide oversight and assure that the work is being performed according to plan. Despite the contractor's extensive experience and despite significant quality assurance requirements which exist in the nuclear industry, mistakes do happen.

Q. Please explain your review of the work stoppage that occurred at Turkey Point Unit 3 in October 2010.

A. At Turkey Point Unit 3 work was stopped on October 16, 2010 due to a Siemens electrician's failure to connect cables in a 480 volt main transformer control cabinet, despite the work having been reported as complete, creating an unsafe situation. The work stoppage lasted for three (3) days.

I reviewed the action request (AR) in which the problem is stated, analyzed, records searched for previous similar occurrences, the root causes as well as contributory causes identified, and an action plan developed to prevent recurrence. The record review as documented in the AR did not reveal any similar situations from October 15, 2007 through November 11, 2010, thus EPU management had no prior basis for concern.

One action immediately taken was to stop all work on the main transformer until it was determined that the action plan was completed. The action plan included procedure revisions and additional training. In my opinion the EPU management performed in a commendable manner as personnel safety should always come first.

Q. Was it appropriate for FPL to hire Siemens to perform this type of work on the unit?

A. As a world leading company in the manufacturing and installation of turbine-generators and associated auxiliary equipment, Siemens was the appropriate choice for this work. Additionally, by 2010 Siemens had performed turbine-generator uprate work on seventeen (17) units, and since it had purchased the non-nuclear business of Westinghouse in 1997, it was and is the original equipment manufacturer (OEM) of the Turkey Point main turbine-generators.

Q. Did FPL provide adequate training and oversight?

A. Yes. FPL hires contractors for their expertise in performing work that FPL does not normally do. The work scope, as well as the interface between FPL and a contractor, is defined in the contract between the parties. Since the uprate work is being performed in operating nuclear plants, FPL's primary mission is to make sure that the job is safe for plant personnel, plant license conditions are being adhered to, that the plant is not damaged, and that the work is accomplished as planned. The EPU project has a suite of procedures that spell out the EPU management responsibilities. I have reviewed the Extended Power Uprate Project Instruction (EPPI) procedures and I find them to be thorough and comprehensive.

Additionally from both a warranty and bargaining unit perspective, FPL, or any client, must exercise restraint in its interaction with workers of a contractor. Any direction given to a contractor worker could jeopardize any warranty for the specific work involved.

On my tours of both Turkey Point and St. Lucie in 2010 and 2011 and in discussions with EPU management I observed what I believe is good understanding of the mission and roles and responsibilities of all EPU participants. This is very important as it was cited as one of the ingredients for a successful project by the St. Lucie Unit 2 project team and a criterion that I used to evaluate the EPU project in my pre-filed testimony.

Q. **Was a work stoppage an appropriate response to the human performance event that occurred?**

A. Yes. Stopping work is prudent when personnel safety is at risk. No one's life should be in jeopardy performing relatively ordinary construction work.

Q. Please explain your review of the work stoppage that occurred at Turkey Point Unit 3 in November 2010.

A. On November 1, 2010 an electrician employed by Bechtel accidentally cut into a Turbine Plant Cooling Water System (TPCW) pipe with a grinding wheel. The affected TPCW pipe was not in service at the time so no serious personnel safety threat existed. Had the TPCW pipe been in service there could have been serious safety consequences. To prevent future occurrences EPU management directed a work stoppage to provide human performance training for craftsmen and supervisors. This work stoppage lasted for fifteen (15) days. This event is discussed in a condition report (CR). The conduit support weld on which the electrician was grinding and the TPCW pipe were very close together as is the case with much equipment at Turkey Point. The CR deals with this situation and prescribes corrective action.

As was the case with the October 16 stoppage, it is my opinion that FPL management took the correct action to prevent what could be a serious situation.

Q. Was it appropriate for FPL to hire Bechtel to perform this type of work on the unit?

A. Yes. As with Siemens, Bechtel is a world leading company in the design and construction of nuclear power plants. Approximately half of the nuclear power plants in the United States were designed and constructed by Bechtel. Bechtel also has extensive experience with retrofit work in nuclear power plants. Such work began about thirty five years ago when the Nuclear Regulatory Commission was formed and its issuance of new regulatory changes resulted in significant plant modifications. As a result Bechtel was a good choice for the Turkey Point work.

Q. Did FPL provide adequate training and oversight?

A. Yes. As described above, the EPU project has a suite of procedures that spell out EPU management responsibilities. I have reviewed the EPPI procedures and I find them to be thorough and comprehensive.

Q. Was a work stoppage an appropriate response to the human performance event that occurred on November 1, 2010?

A. Yes. The safety of personnel could have been at risk. In my opinion EPU management had no choice but to suspend work until it was satisfied that the cause of the problem had been identified and actions taken to prevent its recurrence.

Q. Please describe your review of the work stoppage that occurred at St. Lucie Unit 2 in January 2011.

A. During a Loop test of the Unit 2 generator stator core, hot spots were identified in the stator core iron. A determination was made to remove the iron to correct the hot spots. On February 12, 2011, during the process of un-stacking the core iron to correct the hot spots, Siemens found a core iron alignment pin approximately ten inches inside the stator core. Electrical testing of the stator core by the vendor with the pin in place resulted in damage to a section of the stator core.

A root cause evaluation was jointly performed by EPU management and Siemens and was documented in a CR, which recommended changes to processes and procedures to prevent future occurrences. This was very important because the generators at Turkey Point 3 and 4 and St. Lucie Unit 1 remain to be re-wound.

The analysis documented in the CR identified areas for improvement in Siemens' procedures, especially tool control, and accountability for devices such as alignment pins. As the problem that occurred at St. Lucie Unit 2 apparently had not happened before in Siemens experience, Siemens management apparently believed that their procedures were adequate, and FPL had no basis to question them. After the incident, however, Siemens management took decisive action to change its procedures, and FPL now has inspection points as an added assurance that this will not happen again.

Q. **Was it appropriate for FPL to hire Siemens to perform this type of work on the unit?**

A. As with Turkey Point, FPL hired the OEM to modify the main generator to support the EPU project. One of the main modifications is rewinding the generator with new wire coils to handle the higher output. This type of work is normally done in a factory under controlled conditions, and it is not the type of work for which electric utility organizations are skilled and trained. The reason for performing the rewind at the site is that the other choices, sending the generator to the factory or buying a new one, are much more expensive and require longer outages.

By the time the St. Lucie work began in January 2011, Siemens had completed over twenty (20) on-site generator rewinds, thus there was no reason for FPL to question Siemens' ability to successfully complete the work at St. Lucie. Based on the above the decision to hire Siemens to do the work at the site was the best choice.

Q. Did FPL provide adequate training and oversight?

A. Yes. As described above, the EPU project has a suite of procedures that spell out the EPU management responsibilities. I have reviewed the EPPI procedures and I find them to be thorough and comprehensive.

Q. Was a work stoppage an appropriate response to the human performance event that occurred?

A. Yes. In order to prevent additional damage to equipment or possibly workers, there was really no choice but to suspend work. In cases such as this, it is necessary to get to the cause of the problem, address it, revise processes and procedures, and implement training, all to prevent recurrence. That was the prudent thing to do.

Q. With respect to Witness Jacobs's testimony, how do you respond to his position related to the 2007 decision to expedite the EPU project?

A. Witness Jacobs seems only to be stating the obvious implications of an expedited project approach. "Fast-tracking" is an approach used to manage a project when it is determined that the desired result is best achieved in an expedited fashion. Because the project milestones are planned and executed in a shorter time frame, additional project risks are identified early in the planning process and compensatory actions are established to ensure successful completion of the project. For example, additional oversight or more frequent schedule or cost review meetings with senior management may be implemented to ensure that the key project management areas (e.g., scope, cost, schedule, quality, risk, etc.) are progressing as expected. It should not be surprising that information is learned and complications or risks are identified as the project progresses. In this case, the benefits to customers of putting in service additional low cost, zero emission, base load capacity on an expedited time frame, and the cost savings to customers in completing the project in an expedited timeframe, warranted the expedited approach.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BY MR. ROSS:

Q. Mr. Derrickson, have you prepared a summary, a combined summary of your direct and rebuttal testimony?

A. I have.

Q. Would you please provide that now to the Commission?

A. I can. Good afternoon, Mr. Chairman and Commissioners. I have been involved in the construction of nuclear plants and nuclear projects for over 40 years. I managed the successful completion of construction of St. Lucie Unit 2, one of the few nuclear plants to be completed on schedule and under budget. I also managed the successful completion of Seabrook Station, a nuclear plant in New Hampshire, that was among the most recent plants to be built in the United States. I have also managed several retrofit projects at existing nuclear plants. Recently, I advised on prime contract format and content on two nuclear plants now under construction, and I am currently consulting on another nuclear plant construction project that is the subject of a confidentiality agreement.

The opinions I provide here today are based on the totality of my 40 years of experience in the nuclear and power generation industries, and the fact that the principles of sound project management do not change over time. Based on my review of EPU procedures, documentation required by procedures, such as risk tables, trend reports, training records, site tours, and interviews with EPU management at each site, it is my opinion that FPL prudently managed the EPU project in 2010. The changes in nuclear licensing requirements between the late 1960s and the mid-1980s produced significant differences between the St. Lucie and Turkey Point nuclear plants. These differences have made the current design, construction, and management of FPL's EPU project significantly challenging.

The EPU project also poses unique challenges that are not found in the construction of new plants. These challenges include maintaining personnel safety and safe plant operation while working around energized systems at an existing nuclear plant, working in congested physical space, working in limited time frames such as refueling outages, dealing with emergent work during project implementation, coordination with stringent security requirements and hundreds of incremental plant staff and staging facilities and materials to support the project.

My review also includes the three work stoppages that occurred during execution of FPL's extended power uprate project in late 2010 and in

February of 2011. I addressed the appropriateness and the necessity of the work stoppages on construction projects to ensure safety before allowing work to proceed. It is my experience that to continue to work when conditions exist that are either unsafe for workers or that could potentially damage plant equipment would be imprudent. I reviewed circumstances for each of the three work stoppages and addressed the need for the stoppage in each case to ensure that workers will work safely before work was allowed to proceed.

In making my determination of prudence, I also looked at the selection of the content of the contract companies whose workers were involved in the events that led to the stoppage. My conclusion is that the selection of Bechtel and Siemens was appropriate, based on their vast experience and record in the nuclear industry. I also looked at the appropriateness of FPL's training and oversight of Bechtel and Siemens.

In conducting my examination I reviewed the contract documents and procedures that define EPU's management oversight responsibilities. My conclusion is that FPL's oversight was appropriate. I also provided a response to Witness Jacobs' concerns regarding FPL's decision to expedite the EPU projects. I examined the reasons for expediting a project, and I discuss the additional actions taken to ensure project success. These additional actions include identifying project risks and establishing compensatory actions, such as additional oversight or conducting frequent management review meetings.

I conclude that FPL was prudent in managing the EPU project in 2010, and that the benefits to FPL's customers of putting the EPU project in service -- additional low cost zero emission base-load capacity on an expedited time frame and the additional cost savings to customers by completing the EPU project in an expedited time frame warranted FPL's approach to the project. This concludes my oral summary.

CHAIRMAN GRAHAM: Thank you, sir.

MR. ROSS: We tender the witness for cross-examination.

CHAIRMAN GRAHAM: Ms. Kaufman.

MS. KAUFMAN: Thank you.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. It's almost evening, but good afternoon, Mr. Derrickson.

A. Good afternoon.

Q. I have just one or two questions for you and they involve your March 1 direct testimony. If you would turn to Page 15 on that testimony.

A. I have it.

Q. And at the top of the page the question is asked do costs and schedule projections often change for large projects, such as the EPU; and you respond that that is the case, correct?

A. Correct.

Q. And it's quite a long answer. It goes over to the next page, Page 16. And if you look at Line 7, you talk about the fact that with respect to the EPU project, new scope has emerged as Bechtel addresses and completes the detailed design work, correct?

A. Correct.

Q. So you would expect, would you not, that perhaps the cost and the schedule of this project, the costs would increase and the schedule of it would be pushed out?

A. It may. It depends on whether you have scope increases or decreases. It's possible that you could have both.

Q. But it's certainly possible that the cost of this project will increase and that the in-service date will be pushed out, would you agree?

A. Not necessarily. It's entirely possible for new scope to be included in an existing schedule.

Q. You are familiar with the project, are you not?

A. I am.

Q. And you would agree that as we sit here now, the costs have certainly increased from the original estimate, correct?

A. I was not asked to look specifically at the costs, but I believe other witnesses have testified to that, yes.

Q. That it has increased, correct?

A. Yes.

Q. That's your understanding. You have -- I just want to ask you very brief questions about some of the exhibits that you have attached to this testimony that we are discussing. You attached a paper that you wrote regarding St. Lucie 2, and it's denominated WBD-2?

A. Correct.

Q. When was that paper written?

A. In 1982.

Q. And you have a paper attached as WBD-3, correct?

A. Correct.

Q. And when was that paper written?

A. That paper was written in 1987.

Q. And then you have in WBD-4 another -- some comments, I guess, would be more correct, and when were those remarks or comments authored by you?

A. In the Exhibit 4?

Q. Yes.

A. This piece was published April 21st, 1983.

MS. KAUFMAN: That's all I have. Thank you, Mr. Derrickson.

CHAIRMAN GRAHAM: OPC.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q. Good afternoon, sir.

A. Good afternoon.

Q. I have a couple of questions about your rebuttal testimony as they relate to your rebuttal to OPC Witness Jacobs beginning at 9 and 10.

A. Pages 9 and 10?

Q. Yes. On Page 10 at Line 2 you say -- when referring to the fast-track process, you say because project milestones are planned and executed in a shorter time frame, additional project risks are identified early in the planning process and compensatory actions are established to ensure completion of the project.

Do I understand correctly that this is a general or generic description of the fast-track process as you are describing it?

A. I didn't look at this as a fast-track or a nonfast-track project. I think what was done here was a need determination was made for power in 2012, and a plan was put together to uprate the plants to meet the need for power. And so, you can call it whatever you want to call it, but it was a project plan much as we did for St. Lucie Unit 2 in 1977 because we needed power in 1983. And so you organized a project and are trying to identify what is out there in front of you that might get in your way, and then do the best you can to make the schedule that you committed to your management to do.

I don't know if I answered your question, but that's what it looks to me like happened here, was that they are trying to meet the power needs next year.

Q. Well, at the bottom of Page 9, Line 23, you begin this passage with this statement, fast-tracking is an approach used to manage a project when it is determined that the desired result is best achieved in an expedited fashion, and then you pick up with the additional language to which I referred you. So I understood that statement about identified project risks to be related to your description of a fast-track approach.

A. Right.

Q. My question is is this a general statement as opposed to anything else?

A. Well, the risk that was seen by the project team here was the delivery time for long-lead equipment, like moisture separator, reheaters, condensers, pumps, and those kind of things. So much of that was -- much of that work was done early in the project, the ordering of the large long-lead time equipment.

Q. Okay. So one function in terms of adjusting to conform to a fast-track approach, according to your testimony, is to identify additional risks early on, correct?

A. As best you can, yes.

Q. So if a particular entity underestimated the risks of a fast-track approach, that could have some consequences in terms of inadequate adjustments to the project, correct?

A. Could you repeat that?

Q. Yes. Your proposition is that in managing a fast-track project one identifies risks early and then compensates for that, correct?

A. Yes.

Q. So the extent to which one recognizes or fails to recognize the risk of a fast-track approach would have consequences in terms of whether the compensation is adequate or not, correct?

A. Well, nuclear projects, you know, have a variety of risks. And some risks, for example regulatory risks, probably in most projects can't be identified until there is an engagement with the Nuclear Regulatory Commission. But because people in the business know, you know what to look for and know what the risks have been on other projects.

Q. With respect, sir, that's not responsive.

I'm referring you to your question, to your passage in your testimony where you say that the process is as follows, you fast track, that means you identify risks, and then you compensate for those risks. That is your testimony, correct?

A. Yes.

Q. And my question to you is if one fails to appreciate or underestimates the extent of the risks associated with fast-track, that would bear on the quality of the compensation, correct?

A. It could.

Q. Now, when you say compensatory actions are established to ensure a successful completion of the project, by successful completion of the project, do you mean the objective of having it in place at the desired point in time?

A. Having the project completed on the schedule that was committed to, yes.

Q. So that is not really addressing cost, is it?

A. Costs are a consequence of doing the work.

Q. Yes, and they are also a consequence of doing the work on a fast-track approach, correct?

A. Well, not necessarily. The alternative for doing a project like this, if you were to do it and you wanted to be absolutely sure of, you know, everything, you would do the engineering, then the procurement, then the construction. And according to FPL, it would have taken another six years. If they had done it that way, I doubt we would be here having this conversation, because I think this would have been so expensive because that has been the trend in the nuclear business.

We built St. Lucie Unit 2 on an expedited schedule to meet power needs in 1983. We used innovative construction methods. You can call it whatever you want. We slipformed the containment, for example. We started testing out plant systems two and a half years into the project, which meant we had energized cables and pressurized pipe which typical projects didn't do. But we learned how to do it, we did it right, and the project was finished in 1983, and the cost was half or less than the contemporary plants that didn't do innovative things to try to expedite the schedule.

Q. Now, you speak in terms of identifying project risks and compensating. You have reviewed the testimony of Doctor Jacobs, have you not?

A. I did.

Q. And do you agree with Doctor Jacobs that the traditional approach to construction is to complete the design work and use those specifications to solicit bids, and then select the bids to translate into contracts that have price assurance?

A. That is a way.

Q. And would you agree that when one fast-tracks such that these different phases are preceding in parallel and not in sequence, one must forgo the price assurance aspects of a contract based upon full specifications?

A. As I said, I think that the primary thing that happened here was equipment was ordered early, but no work in the operating part of these plants can be done without the design, because there is a -- the technical specifications require a plant change modification package be put together with the engineering, with the instructions, procedures, and the plant operating review committee has to approve it before the work can be done.

Q. With respect, sir, that was not responsive. My question is this would you agree with Doctor Jacobs that when one conducts these different phases of a construction project in parallel and not in sequence, it is necessary to forgo price-certain contracts because vendors are unwilling to take the risk of costs if they don't have the full specifications of the modification?

A. I don't know that that's true.

Q. On what basis do you disagree?

A. Well, for example, if you wanted a bigger moisture separator reheater, vendors build those. You could order the moisture separator reheater only knowing the parameters that you want, but you would not necessarily have to have designed the system around it.

Q. And in that instance, would the vendor lock itself into a price-certain contract for the work?

A. I believe so, yes. It has been done on many projects. In fact, it not uncommon on nuclear projects to be required to order material before the project even starts. For example, the delivery time for a reactor vessel is five or six years and a steam generator is about the same. And if you wanted to have the shorter schedule, you would have to take the risk and order that equipment before the job started, and it's done all the time.

Q. And when you say take the risk, you're going to -- the price that you agree to pay is going to reflect the risk of proceeding in that fashion, correct?

A. You would only take the risk if you didn't do the project, but you can order material like, you know, those kinds of things and get a fixed price.

Q. A fixed price that reflects the ability of the vendor to shift the risk to the person who wants to proceed in that fashion?

A. No. The vendor -- if a vendor agrees to a price, the vendor agrees to a price.

Q. On that we can agree. But would you agree with me that that price is not going to be the result of a competitive bid situation where these things are going on in parallel?

A. I don't think so, no.

MR. McGLOTHLIN: That's all the questions I have.

CHAIRMAN GRAHAM: Okay.

MR. WHITLOCK: No questions, Mr. Chairman. Thank you.

CHAIRMAN GRAHAM: Anybody? None of the other intervenors. Staff.

MS. NORRIS: Staff has no questions.

CHAIRMAN GRAHAM: Commission board? Redirect?

MR. ROSS: A few on redirect, Mr. Chairman.

REDIRECT EXAMINATION

BY MR. ROSS:

Q. Mr. Derrickson, you were asked some questions about the articles you published about the St. Lucie Unit 2 experience. The principles of project management that you discuss in those articles, have those principles changed in your opinion even as of today?

A. They not only do not change, several professional organizations have memorialized some of our ingredients for successful projects, like the International Atomic Energy Agency in some of their techdot publications, and the International Organization for Standardization. I don't think they ever change.

Q. You were asked some questions by Mr. McGlothlin about an organization's failure to appreciate risks of a fast-track approach. Based on your review of FPL's execution of the EPU project, do you think FPL failed to appreciate the risks of proceeding in an expedited basis on this project?

A. No, I think FPL knew and knows exactly what it is doing, and it's doing almost the same type of project management that we did on St. Lucie Unit 2 to bring that plant in almost on schedule.

MR. ROSS: That's all I have, Mr. Chairman.

CHAIRMAN GRAHAM: Okay. We have some things to enter into the record.

MR. ROSS: The company would move admission of Exhibits 76 through 87.

CHAIRMAN GRAHAM: We are moving Exhibits 76 through 87 into the record. I take it there's no objection to that.

(Exhibits 76 through 87 admitted into evidence.)

MR. ROSS: And, Mr. Chairman, since we have combined Mr. Derrickson's direct and rebuttal, we request that he be excused.

CHAIRMAN GRAHAM: Is there any objection to excusing Mr. Derrickson? Staff?

MR. YOUNG: No objection.

CHAIRMAN GRAHAM: Seeing none. Sir, thank you for your testimony here today.

THE WITNESS: Thank you very much.

CHAIRMAN GRAHAM: We are inching up on our two-hour mark; we'll call it maybe an hour and forty minute mark. But we are going to go ahead and take our five-minute break now. Let's reconvene at twenty till.

(Recess.)

CHAIRMAN GRAHAM: All right. Let's see what you've got.

MR. ROSS: Okay. Mr. Chairman, the Company calls Art Stall. And Mr. Stall has not been sworn.

CHAIRMAN GRAHAM: He has not been sworn?

MR. ROSS: That's correct. Mr. Chairman, Mr. Sim is in the room, he's our next witness, and he can be sworn, as well.

CHAIRMAN GRAHAM: If I can get both of you to stand and raise your right hand.

(Witnesses sworn.)

ART STALL

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

DIRECT EXAMINATION

BY MR. ROSS:

Q. Would you please state your name and business address?

A. My name is Art Stall. I am at 1803 Southwest Foxpoint Trail, Palm City, Florida.

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

A. I am employed currently as a consultant to FPL, NextEra Group.

Q. Have you prepared and caused to be filed six pages of Prefiled Direct Testimony in this proceeding on

March 1st, 2011?

A. I have.

Q. Do you have any changes or revisions to your prefiled direct testimony?

A. No.

Q. If I asked you the same questions contained in your Prefiled Direct Testimony, would your answers be the same?

A. Yes.

MR. ROSS: Mr. Chairman, I ask that the Prefiled Direct Testimony of Art Stall be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert the prefiled testimony of Art Stall into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF ART STALL

DOCKET NO. 110009-EI

MARCH 1, 2011

Q. Please state your name and business address.

A. My name is J. A. (Art) Stall. My address is 1803 SW Foxpoint Trail, Palm City, Florida 34990.

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

A. I am currently a consultant for NextEra Energy, Inc. (NextEra). I previously worked for FPL Group, Inc. (now NextEra) as President, FPL Group Nuclear, and in other nuclear operational positions for NextEra's subsidiaries. In that position, I reported directly to the Chairman and Chief Executive Officer, independent of line management of NextEra's nuclear power operations.

Q. Please describe your previous duties and responsibilities as President, FPL Group Nuclear.

A. The Nuclear organization reports directly to the Chief Operating Officer of NextEra. Accordingly, I was responsible for the overall strategic direction for all of NextEra's nuclear assets, consisting of the four nuclear units owned by Florida Power & Light Company (FPL) in Florida (two at Turkey Point Nuclear Plant and two at St. Lucie Nuclear Plant), and the four nuclear units owned by FPL's affiliates outside of Florida (one unit at Seabrook Station in

Seabrook, New Hampshire; one unit at Duane Arnold Energy Center in Palo, Iowa; and two units at Point Beach Nuclear Plant in Two Rivers, Wisconsin).

Q. **Please describe your educational background and provide an overview of your experience in nuclear operations.**

A. I earned my Bachelor of Science degree in nuclear engineering from the University of Florida in 1977. I also earned a Master's degree in Business Administration from Virginia Commonwealth University in 1983. I am a career nuclear professional with approximately 30 years of nuclear operating experience. I joined Virginia Power Company in 1977, where I held various positions of increasing responsibility, including superintendent of operations, assistant station manager for safety and licensing, and superintendent of technical services. I also held a senior nuclear reactor operator license from the U.S. Nuclear Regulatory Commission (NRC) while working at Virginia Power Company's nuclear plants. In 1996, I joined FPL as the Site Vice President at the St. Lucie Nuclear Plant. From 2000 to 2001, I was Vice President for Nuclear Engineering at FPL. I was named Senior Vice President, Nuclear Operations, and Chief Nuclear Officer at FPL in June 2001, and in 2008 I was named Executive Vice President, Nuclear Operations, and Chief Nuclear Officer. In these positions, I was responsible for the day-to-day operations of all of FPL and NextEra Energy Resources (formerly known as FPL Energy) nuclear plants. In January 2009, I was named President, FPL Group Nuclear, and on May 1, 2010, I retired.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to address particular considerations that arose in the 2010 Nuclear Cost Recovery proceedings with respect to FPL's Extended Power Uprate (EPU) project and to assist the Commission in its understanding of certain aspects of the EPU project, including the development, use and usefulness of preliminary total project cost estimate information.

EPU Project Total Cost Estimates

Q. Please describe the state of the total EPU project cost estimate in the summer of 2009.

A. Through September of 2009, and indeed through the end of the year and into 2010, major factors affecting the EPU total project cost estimate were in a state of flux. FPL had received preliminary cost estimates from its Engineering, Procurement, and Construction (EPC) vendor that were not acceptable to EPU management. After significant challenging, vetting, project scope refinement, and the consideration of alternatives to FPL's EPC vendor, FPL was able to revise its non-binding total project cost estimate. This occurred shortly before it made its filing in this docket on May 3, 2010, which reflected an updated project cost estimate range.

Q. What was the purpose of the July 25, 2009 EPU Executive Steering Committee meeting?

A. The July 25, 2009 Executive Steering Committee (ESC) meeting, which I attended, was to discuss the preliminary cost estimate information received from the EPC vendor, the potential to realize a higher megawatt output from each unit than originally anticipated, changes to project scope (both increases and decreases), and what actions would be appropriate over the next several months. At this time, I participated in ESC meetings, providing independent oversight, but had no direct role or responsibility for the EPU projects.

Q. Are you familiar with the Concentric Report, which is the result of an investigation performed by Concentric Energy Advisors into an employee complaint letter?

A. Yes. I reviewed the Concentric Report and provided a management response letter that is attached to the Concentric Report.

Q. Do you agree with the finding in the Concentric Report that FPL should have revised its testimony to reflect a different EPU project cost estimate in September 2009?

A. No. I do not believe that the testimony provided to this Commission was inaccurate or that it was necessary or appropriate to update that testimony based on some preliminary cost figures provided to FPL from its EPC vendor.

Q. Please explain why you think it would not have been appropriate to revise the EPU testimony on this point.

A. FPL anticipated that as detailed engineering proceeded, there would be changes to project scope. As of September 2009, project scope was indeed growing, which was putting upward pressure on the potential total project cost. However, there were also indications that there were opportunities to eliminate scope and reduce costs that had not yet been acted upon. As explained by Mr. Jones, scope was in fact eliminated in the fall of 2009.

Additionally, FPL received the EPC vendor's estimates for labor costs, which were higher than the estimated costs provided in the bid process, indicating higher total project costs. However, these cost projections had not been fully vetted or challenged by FPL, including executive management, as of the time the testimony was provided. FPL was also considering self-performing some or all of the work and the possibility of hiring a different EPC vendor for some of the work, which had the potential to reduce costs.

In short, the information in FPL's posession in the late July through September time frame provided indications of both the potential for cost estimate increases *and* the potential for cost estimate decreases. Given these competing considerations, FPL could not reliably update its Nuclear Cost Recovery Clause testimony during the September 2009 hearings before the Commission.

Q. What is your conclusion with respect to the provision of this information to the Commission?

A. It is apparent that reasonable minds can differ as to whether the EPU cost estimate information, as it existed in Septebmer 2009, was ready for external communication and reporting. However, the fact that there is disagreement on this issue does not demonstrate any inappropriate action or intentional withholding of information by FPL. To the contrary, it demonstrates FPL's desire to provide reliable, fully vetted information to this Commission.

Q. Do Concentric and FPL agree on the ultimate effect, if any, this had on FPL's customers?

A. Yes. It cannot be said enough that both Concentric and FPL agree that the decision to proceed with the EPU project remained in the best interests of customers, and no imprudent costs were expended. In fact, the costs approved last year for recovery this year were unaffected by the uncertain state of the total project cost estimate.

Q. Does this conclude your testimony?

A. Yes.

BY MR. ROSS:

Q. Mr. Stall, have you prepared a summary of your testimony for the Commission?

A. I have.

Q. Would you please provide that now?

A. Yes. Good afternoon, Mr. Chairman and fellow Commissioners. I'm a career nuclear professional with over 30 years of experience in the nuclear industry, 14 years of which were with FPL Group. I was the Chief Nuclear Officer of FPL from 2001 through 2009, which means that I had overall responsibility for the safe and reliable operation of all of our company's nuclear power plants. I did retire from the company in 2010 and currently consult for the company. I was personally involved in the extended power uprate project, so I do have first-hand knowledge of the events that I will address here today.

Given the unapproved nature of the cost estimates for the extended power uprate project as of September of 2009, the company could not reliably update its Nuclear Cost-Recovery Clause testimony during the 2009 hearings before the Commission. Through September of 2009, and indeed into 2010, major factors affecting the EPU total project cost estimate were in a state of flux. The company had received preliminary cost estimates from its engineering procurement and construction vendor that really were not acceptable to management. As of September of 2009, these cost projections had not been fully vetted or challenged by FPL, including executive management as of the time the testimony was provided.

FPL was also considering self-performing some or all of the work and the possibility of even hiring a different EPC contractor for some of the work which had the potential for cost reductions. For these reasons, the testimony provided to the Commission in September of 2009 was, in fact, complete and accurate in all aspects.

This concludes my summary.

MR. ROSS: Mr. Stall is available for cross-examination.

CHAIRMAN GRAHAM: Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. Good evening, Mr. Stall.

A. Good evening.

Q. Would you agree with me that whenever a witness takes the stand, whether it's a company witness or whomever, that it's important to provide the most accurate, updated information to the Commission?

A. I would with the proviso of as long as it is within the approved processes of the company, that it has been through our process.

Q. I understand from your summary, and I'm assuming that you take issue with some of the conclusions that were reached in the Concentric report regarding that 2009 testimony, is that correct?

A. That is correct.

Q. Were you interviewed by the Concentric team in regard to their report?

A. Unfortunately, no.

Q. You were not. Do you have any reason to doubt that the Concentric report and the people that worked on it did a thorough and objective job in preparing their analysis?

A. I think they did the best job that they could with the information that they had. What they lacked was the information from anybody in the executive steering committee. So, in other words, they did not have the perspective of executive management of the company when they provided that report. And had they received that, I think they would have had a different conclusion.

Q. Is it your understanding -- let me back up. Have you been here since the beginning of the hearing this morning, which seems a very long time ago?

A. No, I just actually walked in the door ten minutes ago.

Q. Okay. Do you have any reason to doubt that Concentric and its team was provided access to all the personnel and to all the documents that they deemed necessary to prepare their report?

A. Well, I wasn't involved. By the time they did their report, I was gone. But having been through a number of these types of situations in the past, I'm sure they had unfettered access to any information they needed.

Q. On Page 15 -- excuse me, Page 5, Line 19 of your testimony, if you want to turn there.

A. Page 5?

Q. Page 5, Line 19, I think it is.

A. Line 19. I'm there.

Q. You talk about the fact that reasonable minds might differ as to the need for the update that has been the subject of our discussion. Do you see that?

A. I do.

Q. Would you agree with me that in the last instance it's the Commission that makes the call as to whether that update should have been provided?

A. Could you repeat that, please?

Q. Yes. Would you agree with me that in the last instance, it's the Commissioners that will make the call as to whether or not FPL should have provided that information to them in September 2009?

A. Well, I think in this case they will make a ruling on that, absolutely.

Q. I want to ask you the same hypothetical -- well, you said you weren't here, but let me just ask you the same hypothetical that I asked Mr. Olivera; and that is, assuming that the Commission accepts the results of the Concentric analysis and finds that up-to-date information was not provided, do you think that it would be appropriate for the Commission to impose a penalty for failing to provide the most accurate and reliable information?

A. No, I do not.

Q. Let me ask it to you this way. Do you not think that it is important that the Commission send a signal to companies that it is their absolute responsibility to provide --

A. Oh, I --

Q. Excuse me. It is their absolute responsibility to provide accurate, reliable, and current information?

A. I do, but I think they have to -- you know, the reason that I answered the way I did is because I was there, and I know that this information had not gone through the company's process. So it was not -- it would have been a violation of policy to release it. So I would disagree if there was a fine, because it wouldn't be the right outcome, in my opinion.

Q. I understand that you disagree, but my hypothetical asks you to accept the fact that the Commission agrees with the conclusion of the Concentric report. And if that were to be the case, would you not agree that they should send a signal and impose a penalty on the company?

A. That would be speculative. I don't want to speculate on that.

Q. You don't have an opinion one way or the other?

A. Well, I have already answered; I don't think that it would be appropriate.

Q. Even if they were to find that the information provided was not the most current and reliable, still you would think that there would be no reason for them to impose a penalty?

A. No, because the information was, in fact, the most current and reliable information. So I would -- I understand it's their purview, and they have that obligation to make that decision. But it would be different than any other decision that has ever been made, because we have a process that we follow at the company for information going external. And this had not been through that process, so it wasn't ripe.

MS. KAUFMAN: Chairman, I'm just going to ask the question one more time and then I'm going to leave it, because I don't think that he is answering. He is continuing to ignore the hypothetical that I'm posing.

CHAIRMAN GRAHAM: Ms. Kaufman, I think that your question was asked and I think it was answered. I believe his answer was I don't have an answer for the hypothetical.

MS. KAUFMAN: If I might?

CHAIRMAN GRAHAM: Sure, please.

BY MS. KAUFMAN:

Q. Was that your answer, Mr. Stall?

A. Yes. You know, you are asking me to speculate on a hypothetical, and I don't want to do that. I don't like to do that.

MS. KAUFMAN: Thank you. That's all I have.

CHAIRMAN GRAHAM: Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q. Hello, Mr. Stall. Please refer to Page 5 of your prefiled testimony.

A. I'm there, Page 5.

Q. I'm looking at Line 11 where you say, in short, the information in FPL's position in the late July through September time frame provided indications of both the potential for cost estimate increases and the potential for cost estimate decreases.

By the potential for cost estimate decreases you are referring to the possible scope deletions, are you not?

A. That is one aspect of it. There were really several things in play. One of them was the scope, which I'm sure you heard earlier today was still in a state of flux. The other is that during that period of time, as you may remember, the economy went sort of through a financial crisis, not unlike what we're going through in the last few days here now. And we were also working very hard on the material side, to go back and renegotiate contracts with our vendors because commodity rises had dropped. For example, copper in transformers and wiring. So we also had, we thought, some opportunities for cost decreases on the material side of the project in addition to the scope.

Q. I want to refer you to the July time frame and the meeting during which the project managers for the

EPU presented the so-called line-by-line analysis of the factors that were bearing on the revised cost estimates. Do you recall that document?

A. I do. You're referring to the presentation to the executive steering committee in July of 2009?

Q. Correct.

Now, isn't it true that within that presentation, and referring again to what we have shorthanded to the line-by-line breakdown, the project managers identified the major categories of costs for the project, and then within each category identified on an item-by-item basis those that appeared to be increasing in cost and those that appeared to be decreasing in cost?

A. Correct.

Q. And within that line-by-line treatment the project managers identified both anticipated increases in scope and opportunities for decreases in scope, did they not?

A. They did.

Q. And with respect to both anticipated increases and prospective decreases in scope, they then quantified those increases or decreases and factored those individual calculations into the overall revised estimate, did they not?

A. That they presented to the executives, correct.

Q. So to that extent, the revised figures, which Concentric reported amounted to an increase of about $300 million, took into account those deletions of scope that could be identified at the time?

A. They did, but there was a fundamental problem with that. And you're correct in that they did come into that meeting and present line-by-line items as we just discussed, but the problem with it was as soon as we drilled down into any particular line two or three questions deep, there was nothing below the surface of substance to back it up from Bechtel in particular.

So it really raised more questions than it answered for us. It cast those number into even further dispute in the minds of myself and the other executives on that steering committee. And then on top of that we had Bechtel, as soon as we came in and shook the tree with them and brought their senior management in, they coughed up 35 or $40 million of reductions immediately. So we walked out of that meeting saying, hey, there's a lot more reductions to be had here than what they are giving us. So it was a line-by-line review, but there was not a lot behind the line-by-line review in terms of depth by Bechtel.

Q. Did you continue to serve on the executive steering committee beyond the July meeting?

A. I did.

Q. You were there for the September meeting?

A. I was asked that, I believe, in my earlier -- when I did my interrogatories. But I can't remember if I was there or not. But I did get copies of the presentations, and I would run into people in the halls and talk to them ad hoc if I wasn't. I was traveling a lot during that period of time.

Q. So you were aware then that during this continued vetting of the numbers, the impact of the additional review was to increase the revised adjustments yet again in September?

A. Yes.

MR. McGLOTHLIN: That's all I have.

MR. WHITLOCK: No questions, Mr. Chairman. Thank you.

CHAIRMAN GRAHAM: Staff.

MS. NORRIS: Staff has no questions for this witness.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman.

Mr. Stall, when you reference that the EPU cost estimate was not fully vetted, can you please explain for us what that term means exactly as it relates to FPL's process?

THE WITNESS: I would be glad to. Thank you. We have at the company, not unlike any other company, and perhaps even here at the Public Service Commission, we have a process that we go through for projects like this.

CHAIRMAN GRAHAM: Sir, can I get you to slide that mike around a little bit.

THE WITNESS: I'm sorry. We have a project -- I mean, we have process that we follow at the company for major capital projects, for investor information releases, any information that is going to be used in a business case to make financial decisions or be released externally to external stakeholders, whether it's the Public Service Commission in this case, the Nuclear Regulatory Commission, or the SEC. And that process is basically one in which the staff, in this case the engineers on the project management team present in a series of reviews to executive management updates as you have seen in these presentations.

And we challenge that, and we push back, and we ultimately come to a decision point where we approve what they are presenting, and it is formally approved at the executive steering committee level. And only then is that information considered approved by the company. It has been fully vetted or challenged and approved in order to be released to an external stakeholder, in this case the Public Service Commission.

And that was what Mr. Reed fundamentally missed in his report, that had he talked to somebody on the executive steering committee he would have gotten, and that was that these numbers were moving all over the place. They were still high and going higher, but we knew two things. We knew, one, that this was still a very good project in terms of cost/benefit for our customers ultimately. There was no question in our minds about that.

And, secondly, that Bechtel, in this particular case, had a history in the industry of running numbers up. And until you pushed back very hard, they would not give up money easily. So we knew we had more work to do. And that's why this information, contrary to some of the words that were in the report that indicated it was approved, it was never approved.

The budget was never changed. The forecast was adjusted, but the budget, which is what would have been the final approval, had never been done. So this wasn't -- we couldn't have gone external without violating our processes.

COMMISSIONER BROWN: If I may, Mr. Chairman.

And just as a follow-up, is that a formal written policy, process?

THE WITNESS: I don't know it's written in a policy and procedure manual. But I can tell you for 15 years and for the ten years that I was in the executive level at the company, this is the process that we used for information that would go to the -- again, to the Nuclear Regulatory Commission, the SEC, the Public Service Commission. In all cases that's the process that we used at the company, and still continue to use.

COMMISSIONER BROWN: Thank you.

THE WITNESS: You're welcome.

CHAIRMAN GRAHAM: Sir, I have a question for you. I think this was asked earlier, and I'm not quite sure I heard the answer to it. The process being that the Concentric report came out and it was presented to the executive steering committee, and then at that point it goes back through a process where they have to approve that. Even though it is presented to them, until they approve it, when they approve it then it gets released.

THE WITNESS: That is correct. It's an iterative process. In a complex project like this, we typically would put the project management team on a short cycle, and by that I mean roughly every month we would have them formally come in and make a presentation to the executive steering committee. And they will get feedback from the executives at that meeting with, I call it, to-do list of action items to go do.

And all during this period of time, I would say from January/February of 2009 through July of 2009, we were having these meetings roughly on a monthly basis, and we were getting disturbing indications that Bechtel, in particular, and particularly with Bechtel, it was their field nonmanual labor on the construction side was going up dramatically. And we couldn't get any real solid rationale or basis as to why that was happening. And we kept sending our guys and ladies back to them between these meetings to try and squeeze them on that to come up with a rationale or reduced costs, and we were getting very little traction.

And then we got to the May/June time frame, and frankly our patience ran out. And that's when we said we wanted to get the president of the company in here and their senior executives for this meeting with them. And that was the July meeting. And, again, what was so bothersome to us was that -- as the question I was asked, when we did the line-by-line reviews and drilled down on some of these numbers, there was nothing of substance to back them up.

And, secondly, just because they met with us, it seemed like they gave up about 35 or $40 million immediately to us. So as soon as we shook their tree, money started falling out of it. So, if anything, we went out there with the idea to redouble our efforts because we thought we could get more out of them going forward. And we didn't approve it at that time.

CHAIRMAN GRAHAM: A question I have, is the report approved by somebody lower than the people in the executive steering committee before it gets presented in the executive steering committee?

THE WITNESS: The report would be approved for presentation to the executive steering committee by the executive -- not a senior executive, but a vice-president level executive who was in charge of that project. So there would be, I'm sure, several iterations of that project presentation going back and forth within the team before it ever got presented to the senior executives. Primarily because most of these workers on this project were not permanent full-time FPL people, but contractors who were still learning our processes and systems.

CHAIRMAN GRAHAM: So shouldn't most of that stuff have been shaken out at that lower level before it got presented to the big cheeses?

THE WITNESS: Ideally that would have been the case. But in this particular case, because we were dealing with particular vendor who has a reputation for this in the industry, of being difficult to deal with on financial and contractual things, it took the senior executive team to really get Bechtel's attention. So that was some of our frustration that I was talking about during that period of time between, say, February and June where we kept telling our project team to get back to Bechtel and ring out some of these costs that didn't make sense. And they would come back the next month with very little to show for their effort.

CHAIRMAN GRAHAM: Okay.

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

And I have one question for this witness, and I actually have a question for you, because at first I thought the witness was confused about your question, and then I come to realize maybe I was confused about your question. I thought that your question for this witness was when the Concentric report, which is Hearing ID Number 197, was presented to someone, and as this witness indicated that the Concentric folks did not meet with anyone on the team that would have had this information that was critical -- and if that isn't your question, I'll just go ahead and ask him.

CHAIRMAN GRAHAM: That wasn't my question.

COMMISSIONER BALBIS: Okay. Well, then I was confused.

The question for you is you indicated that the Concentric representative did not meet with you nor any member of the executive team, is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: And you either said or implied that the members of that team would have that critical information that would have affected their conclusion of whether or not this information was withheld or not, correct?

THE WITNESS: Well, I think that that is correct. If they had met with one or more of the members of the executive steering committee in this particular case, they would have gained the perspective that I have been trying to give here today regarding two things, really. One, at a higher level that we have a process at the company that we use for any information that is important to the company and external stakeholders, that means it has to be fully challenged and vetted and approved before it can go external. He would have certainly gotten that perspective.

And, secondly, he would have gotten the perspective around our interactions with Bechtel, and, in particular, some of the personal experiences that some of our executives on that committee had with Bechtel and some of our fossil projects on the merchant side of the company, which would have even put more clarity in his report.

COMMISSIONER BALBIS: So then my question, then, I would have assumed that when a draft of the report was prepared and submitted, since they were hired by FPL to perform this service, that such an omission would have been brought to their attention so that they could conduct the additional investigation or interviews. Now, what was the process for when the draft was prepared, if there was a draft, or did you want them to be independent, just give me the final report and it will be finished without review?

THE WITNESS: Well, I can tell you my personal experience. When the draft was repaired -- prepared, excuse me, I was contacted. By that time I had retired, but I was contacted and asked to review the draft. And I reviewed the draft, and I raised these issues that I'm bringing out today. And I did speak with John Reed, the Concentric CEO, and I gave him this perspective, but for whatever reason he wasn't receiving it and wasn't going to change the report. So I was disappointed with that. He acknowledged it and was polite, but wouldn't change the report.

COMMISSIONER BALBIS: Okay. Thank you.

And it brings me to my original question. You had mentioned, and it was mentioned previously by another witness that it was a vetting process, and you have discussed the internal policy, whether written or not, and how information gets disseminated and when. The previous information that was submitted to the Commission as part of that 2009 hearing, did that go through that vetting process? So, in other words, were the processes the same, it's just that information was not placed through that process?

THE WITNESS: The information that was presented in September of 2009 in its entirety that was presented to the Public Service Commission absolutely went through that process and was fully vetted and validated and approved by executives at the company.

So in this particular case, the person that presented that testimony, had he revealed or talked about those numbers that are in question in the Reed report, he would have really done two things; number one, he would have been violating a company policy and procedure, which would not have been a good thing. And, secondly, he would have undermined our position with Bechtel in negotiating and attempting to get cost reductions, because it would have lended some sort of legitimacy, perhaps, to it.

COMMISSIONER BALBIS: Okay. Thank you. I don't have any further questions.

CHAIRMAN GRAHAM: Okay. Redirect.

MR. ROSS: Mr. Chairman, to make the record clear, and maybe I'm confused, but the questions that you were asking of Mr. Stall and what I have heard you say, and I think Commissioner Balbis heard the same thing, you asked Mr. Stall whether the report -- and I thought I heard you say the report, the Concentric report had been through this vetting process. I think Mr. Stall was answering a different question.

In other words, I thought that what you meant to say was had the numbers, the numbers that have been presented to the executive steering committee, had it gone through this vetting process.

THE WITNESS: Okay. Well, then if you were asking me that question, was the Concentric report through this process, is that what you were asking me?

CHAIRMAN GRAHAM: Actually, what I asking was the numbers. I said report, I meant to say the numbers.

THE WITNESS: Okay. I believe I answered --

CHAIRMAN GRAHAM: You answered what I was thinking.

THE WITNESS: I thought I did. Okay.

MR. ROSS: Okay. Thank you.

CHAIRMAN GRAHAM: I can't speak for Commissioner Balbis, but --

COMMISSIONER BALBIS: I think I was clear in that the two questions I asked, one was what I thought you had asked and there was some confusion from FPL on it, and that was -- my question was the Concentric report on any draft, how it was reviewed. And you answered that for me. And then the other was, again, the process of vetting, whether the information provided in September of 2009 went through the same process that the new information had yet to go through. And you answered that to my satisfaction.

CHAIRMAN GRAHAM: Was that clear, or do I need to make it --

MR. ROSS: I think it's now clear in the record.

CHAIRMAN GRAHAM: Okay.

MR. ROSS: Mr. Stall, I have a few questions on redirect.

REDIRECT EXAMINATION

BY MR. ROSS:

Q. You were asked about your reaction to the Concentric report. Did you write a paper documenting your reaction to the report?

A. I did.

Q. Do you know if that's an appendix to the report?

A. I believe it was appended to the report.

Q. Okay. You were asked some questions by Mr. McGlothlin about whether the numbers presented to the executive steering committee in September had increased, so I'll ask you a question about that.

Had those numbers that were presented to the executive steering committee meeting in September of 2009 been through the vetting process that you just described?

A. No, not at all. Not at that point in time.

Q. So, in your view, the higher number that had been presented, the higher forecast number that had been presented to the executive steering committee in September 2009, would it have been appropriate at that time for the company to have provided that number to the Commission?

A. No. I thought I said that previously, but just to clarify, no, it would have been inappropriate.

MR. ROSS: No further questions.

CHAIRMAN GRAHAM: Okay. We don't have any exhibits due.

MR. ROSS: No exhibits from this witness, Mr. Chairman.

CHAIRMAN GRAHAM: Okay. And is there any rebuttal for this witness?

MR. ROSS: Yes, there is, and the witness will come back at the time of rebuttal.

CHAIRMAN GRAHAM: Okay. Sir, we thank you for your testimony today.

THE WITNESS: Thank you.

MR. ANDERSON: FPL calls as its next witness Doctor Stephen Sim.

STEVEN R. SIM

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

DIRECT EXAMINATION

BY MS. CANO:

Q. Good afternoon, Doctor Sim.

A. Good afternoon.

Q. Have you already been sworn?

A. Yes, I was earlier.

Q. Okay. Would you please state your name and business address for the record?

A. My name is Steve Sim; business address, 9250 West Flagler Street, Miami.

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

A. By Florida Power and Light as Senior Manager, Integrated Resource Planning.

Q. Did you prepare and cause to be filed 36 pages of Prefiled Direct Testimony in this proceeding on May 2nd, 2011?

A. Yes.

Q. And did you cause to be filed two pages of errata to that testimony on June 10th, 2011?

A. Yes.

Q. Did you also prepare and cause to be filed eight pages of Prefiled Supplemental Direct Testimony on July 15th, 2011?

A. Yes.

Q. And did you also cause to be filed two pages of errata to that supplemental testimony on August 4th, 2011?

A. Yes.

Q. Do you have any other changes or revisions to make to your testimony at this time?

A. Not that I know of, no.

Q. If I were to ask you the same questions today that are contained in your direct and supplemental testimony, would your answers be the same?

A. Yes, they would.

MS. CANO: Mr. Chairman, I would ask that the Prefiled Direct and Supplemental Testimony of Doctor Sim be entered into the record as though read.

CHAIRMAN GRAHAM: We will enter Doctor Sim's Direct Testimony and Supplemental into the record as though read.

MS. CANO: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO. 110009- EI

May 2, 2011

Q. Please state your name and business address.

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 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 concerned the development, monitoring, and cost-effectiveness 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. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring the following 12 exhibits:

- Exhibit SRS – 1: Summary of Results from FPL's 2011 Feasibility Analyses of the EPU and Turkey Point 6 & 7 Projects (Plus Results from Additional Analyses);
- Exhibit SRS – 2: Comparison of Key Assumptions Utilized in the 2010 and 2011 Feasibility Analyses of FPL Nuclear Projects: Projected Fuel Costs (Medium Fuel Cost Forecast);

- Exhibit SRS – 3: Comparison of Key Assumptions Utilized in the 2010 and 2011 Feasibility Analyses of FPL Nuclear Projects: Projected Environmental Compliance Costs (Env II Forecast);
- Exhibit SRS – 4: Comparison of Key Assumptions Utilized in the 2010 and 2011 Feasibility Analyses of FPL Nuclear Projects: 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 2010 and 2011 Feasibility Analyses of FPL Nuclear Projects: Other Assumptions;
- Exhibit SRS – 7: The Two Resource Plans Utilized in the 2011 Feasibility Analyses of the EPU Project;
- Exhibit SRS – 8: 2011 Feasibility Analyses Results for the EPU Project: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios in 2011$;
- Exhibit SRS – 9: 2011 Feasibility Analyses Results for the EPU Project: Percentage of FPL's Fuel Mix from Nuclear, 2010 - 2020
- Exhibit SRS – 10: The Two Resource Plans Utilized in the 2011 Feasibility Analyses of Turkey Point 6 & 7;
- Exhibit SRS – 11: 2011 Feasibility Analyses Results for Turkey Point 6 & 7: Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2011$; and,

- Exhibit SRS – 12: Direct Testimony and Exhibits of Steven R. Sim in the 2010 NCRC docket.

Q. What is the purpose of your testimony?

A. My testimony provides the results of the 2011 economic analyses for the extended power uprates (EPU) project for FPL's existing nuclear units, and for the new FPL nuclear units, Turkey Point 6 & 7, using current assumptions. In my testimony I will refer to these analyses as the 2011 feasibility analyses for both projects. I also present the results of additional analyses of the two nuclear projects. In addition, I shall also discuss the assumptions used in the 2011 feasibility analyses. Because last year's determination was deferred pursuant to a stipulation, I have also attached my 2010 direct testimony and exhibits as Exhibit SRS – 12.

The 2011 feasibility analyses are presented to satisfy the requirement of Subsection 5(c)5 of the Florida Administrative Code Rule 25-6.0423, Nuclear Power Plant Cost Recovery which states "By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the power plant."

Q. Has the Florida Public Service Commission provided guidance regarding what is required in these feasibility analyses?

A. Yes. On November 19, 2009, in Order No. PSC-09-0783-FOF-EI, page 14, the Florida Public Service Commission (FPSC) provided such guidance. In regard to analyses of FPL's Turkey Point 6 & 7 units, the relevant part of this order stated:

"On page 29 of Order No. PSC-08-0237-FOF-EI, we provided specific guidance to FPL regarding the requirements necessary to satisfy Rule 25-6.0423(5)(c)5, F.A.C. The Order reads as follows:

"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."

Q. What is the scope of your testimony?

A. My testimony addresses four main points:

(1) The analytical approaches used in FPL's 2011 feasibility analyses are briefly discussed and compared to the analytical approaches utilized in prior economic analyses of the two nuclear projects.

(2) Various updated assumptions used in the 2011 feasibility analyses are compared to the assumptions that were previously used in the 2010 analyses. The resulting "directions" of these assumption changes, in regard to the economics of the nuclear projects being favorable or

unfavorable, are also briefly discussed. A brief discussion of the nature of the updated assumptions used in the feasibility analyses, and of the feasibility analyses is also provided.

(3) The results of the 2011 feasibility analyses, plus the results of other analyses, of the EPU project are provided.

(4) The results of the 2011 feasibility analyses, plus the results of other analyses, of the Turkey Point 6 & 7 project are provided.

Other feasibility-related topics for the EPU project are discussed by FPL Witness Jones. Additionally, other feasibility-related topics for the Turkey Point 6 & 7 project are discussed by FPL Witness Scroggs.

Q. Please summarize your testimony.

A. In its 2011 feasibility analyses, FPL utilized analytical approaches that it believes are currently the best approaches with which to evaluate the two nuclear projects. FPL also utilized an updated set of assumptions in its 2011 feasibility analyses.

There are a number of assumptions that must be made in any economic analysis of resource options such as the EPU project and the Turkey Point 6 & 7 project. Many of these assumptions are frequently, if not constantly, changing. However, in order to perform economic analyses that will be the focus of a months-long regulatory process such as this docket, it is customary and desirable to "freeze" assumptions and perform the economic analyses utilizing these "frozen" assumptions. Portions of the testimonies of FPL Witnesses Jones and Scroggs discuss the development of these assumptions and much of my testimony presents the results of the economic analyses using these assumptions.

The results of the 2011 feasibility analyses for both projects, plus the results of additional analyses, are summarized in Exhibit SRS – 1. This exhibit presents the following information:

1) Both nuclear projects are projected overwhelmingly to be cost-effective for FPL's customers. The EPU is projected to be cost-effective in all 7 of 7 scenarios of fuel costs and environmental compliance costs. Turkey Point 6 & 7 are projected to be cost-effective in 6 of these 7 scenarios and are breakeven in the remaining scenario which assumes a combination of low fuel costs and low environmental costs for the entire analysis period.
2) The projected nominal fuel savings for FPL's customers from the two nuclear projects are significant. Using a Medium fuel cost/Medium environmental compliance cost (Env II) scenario as an example, the EPU is projected to save approximately $106 million (nominal) in fuel costs in the first full year of operation of the uprated nuclear units. Turkey Point 6 & 7 are projected to save approximately $1.07 billion (nominal) in fuel costs in the first full year of operation for both units.

3) Using this same fuel cost/environmental compliance cost scenario, the EPU is projected to save approximately $4.6 billion (nominal) in fuel costs over the life of the project, and Turkey Point 6 & 7 are projected to save approximately $75 billion (nominal) over the life of the units.

4) The two nuclear projects will also significantly improve the fuel diversity of the FPL system. In their first full year of operation, the EPU is projected to reduce FPL's dependence upon natural gas by approximately 2%, and to allow FPL to increase nuclear energy's contribution to system fuel mix above the current (for the year 2010) 20.0% contribution for the remainder of this decade. Turkey Point 6 & 7 are projected to reduce FPL's dependence upon natural gas by approximately another 13%. Nuclear energy from these projects will supply the amounts of energy that would otherwise have been supplied predominately by natural gas.

5) The amounts of increased energy that nuclear energy is projected to supply in the first full year of operation (and in subsequent years) from the two nuclear projects is equivalent to the total annual energy usage of approximately 209,500 residential customers for the EPU, and of approximately 1,232,100 residential customers for Turkey Point 6 & 7.

6) Stated another way, these amounts of energy projected to be supplied respectively by the two projects will save enormous amounts of fossil fuel. For illustrative purposes, if the same amounts of energy were to be supplied by conventional steam generating units, then the amount

of annual energy mentioned above for the EPU would require the consumption of approximately 29 million mmBTU of natural gas, or 5 million barrels of oil, annually. Likewise, the amount of annual energy mentioned above for Turkey Point 6 & 7 would require the consumption of approximately 177 million mmBTU of natural gas, or 28 million barrels of oil, annually.

7) The projected reductions in carbon dioxide (CO_2) emissions are also very large. Over the life of the projects, the EPU and Turkey Point 6 & 7 are projected to reduce CO_2 emissions by approximately 31 million tons and 287 million tons, respectively.

8) Stated another way, these projected amounts of total CO_2 reductions are equivalent to operating all of FPL's large system of generating units with zero CO_2 emissions for approximately 9 months in the case of the EPU, and for approximately 7 years in the case of Turkey Point 6 & 7.

Therefore, the results of FPL's 2011 feasibility analyses are that both the EPU and Turkey Point 6 & 7 are projected to be solidly cost-effective and to provide valuable firm capacity, energy, and fuel diversity for FPL's customers. These results fully support the feasibility of continuing both nuclear projects.

I. 2011 Feasibility Analyses – Analytical Approaches

Q. Were the analytical approaches used in FPL's 2011 feasibility analyses of the EPU and Turkey Point 6 & 7 similar to the approaches used in the Determination of Need filings for these projects, and in the feasibility analyses of these projects that were presented in previous NCRC filings?

A. Yes. The analytical approaches that were used in the 2011 feasibility analyses for both the EPU and Turkey Point 6 & 7 projects were virtually identical to the approaches used in the 2007 Determination of Need filings and in the feasibility analyses presented in the 2008, 2009, and 2010 NCRC filings.

Q. Please describe these analytical approaches.

A. In regard to the EPU project, the analytical approach used is the direct comparison of the cumulative present value of revenue requirements (CPVRR) for resource plans with and without the uprated capacity at FPL's four existing nuclear units that will result from the EPU project. This same analytical approach was utilized in the 2007 Determination of Need filing, and in the 2008, 2009, and 2010 NCRC filings, for the EPU project.

In regard to the Turkey Point 6 & 7 project, the analytical approach used is the calculation of breakeven overnight capital costs (in terms of $/kw) for the new nuclear units. This same analytical approach was utilized in the 2007 Determination of Need filing, and in the 2008, 2009, and 2010 NCRC 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 analytical approach may emerge as more appropriate.

Q. **Please provide an overview of these analytical approaches.**

A. The basic analytical approach in the feasibility analyses 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, for each scenario of fuel cost/environmental compliance cost, are developed 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, operation and maintenance (O&M), etc. 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 contains the nuclear resource option that is being evaluated in a specific feasibility analysis; i.e., either the EPU or the Turkey Point 6 & 7 units. The other resource plan contains another, non-nuclear resource option that competes with this nuclear resource option. The competing resource option is a new highly fuel-efficient combined cycle (CC) generating unit of the type that FPL is constructing at its existing Cape Canaveral and Riviera plant sites in its modernization projects at those 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 impacts of the resource options being evaluated. FPL's 2011 feasibility analyses address these cost impacts. In addition, my testimony provides a discussion of two non-economic impacts, increased system fuel diversity and system emission reductions, which will result from the two nuclear projects.

II. 2011 Feasibility Analyses – Updated Assumptions

Q. Do FPL's 2011 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. By early 2011, FPL updated these assumptions and is using them in its 2011 resource planning work including the analyses presented in this docket.

In regard to this FPSC Order, five informational items were listed 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 forecasts;

(3) breakeven costs;

(4) capital cost estimates; and,

(5) sunk costs.

FPL's 2011 feasibility analyses for Turkey Point 6 & 7 include FPL's current assumptions for each these five items. In regard to FPL's feasibility analyses for the EPU project, FPL has included current assumptions for four of these five items: items (1), (2), (4), and (5). Because the analytical approach for the EPU project utilizes CPVRR results instead of the breakeven capital cost results used in the analyses of Turkey Point 6 & 7, item (3) (breakeven costs) is not relevant to analyses of the EPU project.

Q. Do FPL's feasibility analyses include FPL's updated assumptions for information other than these 5 items?

A. Yes. FPL updated a number of other assumptions by early 2011 in preparation for all of its 2011 resource planning work. Consequently, these other updated assumptions are also included in FPL's 2011 feasibility analyses. A partial listing of these other assumptions include: FPL's load forecast, projected incremental capacity by year from the EPU project, and financial/economic assumptions.

Q. Please discuss the changes in the forecasted values for fuel costs, environmental compliance costs, and peak load between the forecasts

utilized in the 2011 feasibility analyses and those that were used in the 2010 feasibility analyses.

A. Exhibits SRS – 2 through SRS - 4 provide these comparisons. Exhibit SRS - 2 provides 2010 and 2011 forecasted Medium fuel cost values for selected years for natural gas, oil, and nuclear fuel costs. As shown in this exhibit, the Medium fuel cost 2011 forecast for natural gas is lower compared to the 2010 forecast. A comparison of the forecasted prices for 1% sulfur oil shows a largely similar pattern with the 2011 forecasted values being generally lower. In regard to forecasted nuclear fuel costs, the 2011 and 2010 forecasted prices are essentially unchanged.

Exhibit SRS – 3 presents similar 2010 and 2011 information for forecasted Env II (i.e., mid-level) environmental compliance costs for three types of air emissions: sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). As shown in the exhibit, the forecasted compliance costs for both SO_2 and NO_x are significantly lower with the 2011 forecast compared to the 2010 forecast. This decrease in forecasted SO_2 and NO_x compliance costs is driven by various factors including the anticipated reaction by utilities to add scrubbers and selective catalytic reduction systems (SCRs) in response to the EPA's Clean Air Transport Rule and Maximum Achievable Control Technology rules. This anticipated reaction by the electric utility industry would significantly reduce emissions and result in more allowances being available on the market, thus lowering projected allowance prices.

The differences between the 2011 and 2010 forecasted compliance costs for CO_2 are not as pronounced. The 2011 forecasted costs are assumed to begin later than in the 2010 forecast. In addition, the 2011 forecasted values are generally slightly higher in the earlier years, and are lower in later years, compared to the 2010 forecasted values.

Exhibit SRS – 4 presents the 2010 and 2011 Summer peak load forecasts. As shown in Column (3) of this exhibit, the 2011 forecast of Summer peak load, compared to the 2010 forecast, shows lower Summer peak loads through 2014, higher peak loads for 2015 – 2017, lower peak loads for 2018 – 2020, then higher peak loads from 2021 – on.

In addition, Exhibit SRS – 4 also provides a projection of the annual and cumulative growth in Summer peak loads associated with the 2011 peak load forecast. In column (5) of this exhibit, it is clear that FPL projects a cumulative growth in Summer peak load of approximately 5,844 MW by 2022; i.e., the year in which the first of the two new nuclear units, Turkey Point 6, is projected to go in-service.

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's current DSM Goals are met through 2019 and that an additional 100 MW per year of DSM are implemented from 2020 through 2025. This exhibit shows that, without the EPU and Turkey Point 6 & 7, and with no new generating resources added after the modernizations of Cape Canaveral (in 2013) and Riviera (in 2014), FPL has a need for new resources starting in 2016 and this need increases every year thereafter. The need in 2016 is for 374 MW of new generating capacity and this need increases to 5,329 MW by 2025.

Q. What other assumptions changed from the 2010 analyses to the 2011 analyses?

A. Exhibit SRS – 6 presents the 2010 and 2011 projections for 13 other assumptions that were utilized in the feasibility analyses. These other assumptions are grouped into three categories of either four or five assumptions each: (i) assumptions used in the feasibility analyses of both projects; (ii) assumptions primarily used only in the feasibility analyses of the EPU project; and (iii) assumptions primarily used only in the feasibility analyses of the Turkey Point 6 & 7 project. (Note that some of the assumptions included in the second and third groupings do have an impact in the feasibility analyses of both projects. Examples of such assumptions are the incremental capacity of the EPU project and the in-service dates of Turkey Point 6 & 7. The grouping of assumptions such as these into either the second or third groupings is done solely to facilitate discussion in this testimony of changes in assumptions.)

Q. Please discuss the first grouping of these other assumptions; i.e., those assumptions that are applicable in the feasibility analyses for both projects.

A. The five assumptions included in this grouping are:

1) the number of environmental compliance cost scenarios;

2) financial/economic assumptions;

3) the capital cost of competing CC capacity;

4) the 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 2011 feasibility analyses, FPL is again using three such scenarios in its 2011 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 2011 feasibility analyses have changed from those used in the 2010 feasibility analyses. The allowed return on equity (ROE) of 10.0% is unchanged, the allowed cost of debt has decreased from 6.48% to 5.50%, and the debt-to-equity ratio has changed from 44.8%/55.2% to 40.88%/59.12%. As a result of these changes, the associated discount rate has decreased slightly from 7.30% to 7.29%.

The remaining three assumptions that are included in this first grouping of assumptions involve the costs of the competing CC capacity used in the feasibility analyses. FPL's current projected (generator only) capital cost of CC capacity is $832/kw in 2018$. The current projected heat rate of this CC capacity is 6,607 BTU/kwh, and the projected firm gas transportation cost is $1.98/mmBTU in 2018. The projected capital cost of the CC unit and firm gas transportation cost are lower than projected in 2010. The projected heat rate value is higher than projected in 2010.

Q. Please discuss the second grouping of other assumptions that primarily address the EPU project.

A. The four assumptions included in this second grouping are:

1) incremental capacity from the EPU project;
2) non-binding capital cost estimate of the EPU project
3) previously spent capital costs for the EPU project that are excluded from the 2011 feasibility analyses; and,
4) the "going forward" capital costs included in the 2011 feasibility analyses.

The assumptions for incremental MW and costs are for FPL's share of the EPU project.

In regard to the first assumption, the projected incremental capacity that FPL's customers will receive from the EPU project, this value has not changed from the 450 MW used in the 2010 feasibility analyses. However, FPL is now projecting to receive 17 MW Summer and 17 MW Winter from its St. Lucie 2 unit beginning in the Spring of 2011 as a result of the EPU project. (At the time that assumptions were frozen for the feasibility analyses, FPL assumed that this interim increase of 17 MW would occur in April 2011. The interim increase is now projected to occur in May 2011.) These 17 MW represent an "interim" increase from the EPU work for St. Lucie 2. (There are no projected interim capacity increases from EPU work at any of the other three nuclear units.) Previously, FPL had projected that it would receive no incremental capacity at any of the four nuclear units until the EPU work is fully completed. FPL Witness Jones discusses this interim increase in capacity in his testimony.

The combination of the next three assumptions provides the projected incremental capital cost to FPL's customers of completing the EPU project. The projected non-binding capital cost range for the EPU project is discussed in FPL Witness Jones' testimony. In the 2010 feasibility analysis, FPL used the upper end of the then current capital cost range: approximately $2.30 billion. For the 2011 feasibility analyses, FPL is using the upper end of the current capital cost range: approximately $2.48 billion.

FPL Witness Powers provides the sunk cost value for the EPU project in her testimony. In the 2010 feasibility analysis, FPL excluded approximately $0.35

billion of costs that were spent in 2008 and 2009, resulting in a "going forward" capital cost projection for completing the EPU project of approximately $1.95 billion (= $2.30 billion - $0.35 billion). In the 2011 feasibility analyses, FPL is excluding approximately $0.70 billion of sunk costs that have been spent in the 2008 – 2010 time period, resulting in a "going forward" capital cost projection for completing the EPU project of approximately $1.78 billion (= $2.48 billion - $0.70 billion).

Q. Please discuss the third grouping of other assumptions that primarily address the Turkey Point 6 & 7 project.

A. The four assumptions included in this third grouping are:

1) assumed in-service dates for Turkey Point 6 & 7;

2) non-binding capital cost estimate for the new nuclear units;

3) previously spent capital costs that are excluded from the 2011 feasibility analyses; and,

4) the cumulative annual capital expenditure percentages for Turkey Point 6 & 7.

The first of these assumptions, the projected in-service dates, for planning purposes, of Turkey Point 6 & 7 are unchanged from the 2022 and 2023 in-service dates used in the 2010 feasibility analyses. FPL Witness Scroggs' testimony addresses these dates which represent the earliest practical deployment dates for these new units.

The second of these assumptions is the non-binding cost estimate for constructing Turkey Point 6 & 7. The updated range of costs used in the 2011 feasibility analyses is $3,483/kw to $5,063/kw in 2011$. FPL Witness Scroggs' testimony discusses the updating of this assumption.

The third of the assumptions included in this grouping is the previously spent capital costs that are excluded in the 2011 feasibility analysis. In order to account for "sunk" capital costs for the Turkey Point 6 & 7 project, FPL is excluding approximately $129 million of sunk costs that have already been spent in the 2006 – 2010 time period. This represents an increase of approximately $31 million compared to the approximately $98 million sunk cost value utilized in FPL's 2010 feasibility analyses. FPL Witness Powers provides the sunk cost value of the Turkey Point 6 & 7 project in her testimony.

The fourth assumption in this grouping is the cumulative annual capital expenditure percentages for the construction of Turkey Point 6 & 7. The annual expenditure percentage values in the 2011 feasibility analyses are essentially unchanged from the values used in the 2010 feasibility analyses.

Q. It is clear that a number of changes in assumptions were made between those used in the 2010 feasibility analyses and those used in the 2011 feasibility analyses. Were all of these assumption changes favorable to the economics of the EPU and Turkey Point 6 & 7 projects?

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 two nuclear projects in regard to the changes in assumptions from those used in the 2010 feasibility analyses to those used in the 2011 feasibility analyses. Using the EPU project as an example, some updated assumptions (such as the lower fuel cost projections) are unfavorable for the project (although favorable overall for FPL's customers) while other updated assumptions (such as interim incremental capacity from the St. Lucie 2 unit) are favorable for the project (and for FPL's customers).

All of the updated assumptions, whether favorable or unfavorable for the two nuclear projects, were included in FPL's 2011 feasibility analyses.

Q. You have already stated that the assumptions used in FPL's 2011 feasibility analyses have been updated. Would you please discuss the manner in which these assumptions are updated and utilized in this docket?

A. Yes. Assumptions that are used in economic analyses conducted by FPL, such as FPL's 2011 feasibility analyses for this docket, are subject to frequent change. Furthermore, some inputs, such as projected fuel costs, are changing almost constantly. In order to perform an economic analysis, it is necessary to "freeze" these assumptions at some point so that the analyses can begin. At that point in time, FPL's approach is to utilize these "frozen" assumptions throughout the analyses and all of the subsequent examination of the results of the analyses. In regard to FPL's nuclear feasibility analyses, these assumptions are typically frozen roughly one-to-three months prior to the time that the results of the analyses are presented in testimony filed with the FPSC in order to complete and review the analyses, then incorporate the results of the analyses into FPL's testimony.

Q. **Is this approach to freezing assumptions for the annual nuclear feasibility analyses typical in regard to analyses whose results are filed with the FPSC?**

A. Yes. In my approximately 20 years of performing analyses for use in FPSC filings, and in presenting analyses results to the FPSC in testimony, this approach of freezing assumptions for use in an FPSC docket has consistently been used. Therefore, I believe that it is customary to use this approach in FPSC dockets. In addition, I believe it is also desirable to use a "frozen" assumption approach through the course of FPSC dockets that address resource options.

Q. **Please explain why you believe it is desirable to utilize a frozen assumption approach through the course of FPSC dockets involving resource options.**

A. FPSC dockets involving resource options typically last a number of months and generally consist of the following five stages:

- Direct testimony of the utility;
- Discovery by all parties;
- Intervener testimony;
- Rebuttal testimony of the utility; and
- The FPSC hearing.

The first stage, the utility's direct testimony, introduces the assumptions used in its analyses and the results of the analyses using these assumptions. Subsequent stages of the regulatory process use the information presented in the first stage, including the assumptions, as the basis for all of the work that follows.

If the utility were to "unfreeze" assumptions at some later point in the process, it would have to redo its analyses due to the introduction of the new assumption information. As a result, the work that had been performed up to that point by all parties (utility direct testimony, discovery, intervener testimony, and utility rebuttal testimony) would be of reduced value and might have to be discarded entirely. This is especially true when one considers the desirability of using a consistent set of assumptions that are developed at the same point in time. If consideration were to be given for updating a specific assumption at some time after the utility's filing of its direct testimony, then consideration should be given to updating all assumptions at the same time. If all assumptions were to be updated, then the docket process would essentially be returning to the beginning of the first stage; i.e., the process would be starting over from the beginning.

At a minimum, the introduction of new assumptions would introduce confusion and the possibility of delays into the docket. Neither of these outcomes is desirable.

Q. Does the annual nature of the nuclear cost recovery dockets provide further support for the frozen assumption approach?

A. Yes. The nature of the annual nuclear cost recovery docket process is that assumptions and analyses are required to be updated on a regular basis; i.e., each year. Consequently, the utility, the interveners, and the FPSC annually examine the results of the utility's feasibility analyses using updated assumptions. The fact that each feasibility analysis presented to the FPSC is one of a continuum of feasibility analyses provided over a number of years further supports the frozen assumption approach that FPL utilizes for each individual feasibility analysis filing.

III. 2011 Feasibility Analyses Results for the EPU Project

Q. What resource plans were used to perform the 2011 feasibility analyses of the nuclear uprates project?

A. The two resource plans that were utilized in the 2011 feasibility analyses for the EPU project are presented in Exhibit SRS – 7. As shown in this exhibit, the new generating unit additions in the two resource plans are identical through 2018 except for the addition of the incremental MW from the EPU project in the years 2011 - 2013. The two resource plans begin to differ starting in 2019. In the Resource Plan without EPU, a new CC unit is added in 2019 and another is added in 2021. Due to the 450 MW of additional capacity supplied by the EPU project, the Resource Plan with EPU needs no additional generation in 2019. A new CC unit is added in 2020, but no additional capacity is needed in 2021. Finally, there are also differences between the two resource plans in regard to the amount of "filler unit" capacity added from 2024 – on due to the different amounts of capacity added in the two resource plans through the year 2021.

Q. What were the results of the 2011 feasibility analyses for the EPU project?

A. The results of the 2011 feasibility analyses are presented in Exhibit SRS – 8. As shown in Column (5) of this exhibit, the Resource Plan with the EPU Project is projected to have a lower CPVRR cost in 2011$, compared to the Resource Plan without the EPU Project, in 7 of 7 scenarios of fuel cost and environmental compliance cost forecasts utilized in the analyses.

Q. In addition to the results of these CPVRR-based analyses, did FPL's 2011 feasibility analyses identify any additional advantages for FPL's customers that are projected to be derived from the EPU project?

A. Yes. I will discuss three other advantages to FPL's customers that are projected to result from the EPU project:

1) system fuel savings;
2) system fuel diversity; and,
3) system CO_2 emission reductions.

These advantages will be discussed using the results from the 2011 feasibility analyses for the Medium Fuel Cost, Env II scenario.

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. However, it is informative to also look at the annual nominal fuel savings projections.

In 2013, the first year in which the uprated capacity at all four existing nuclear units will be in operation for virtually an entire year, the nuclear uprates are projected to save FPL's customers approximately $106 million (nominal) in fuel costs. Over the life of the current operating license terms of the four uprated nuclear units, the total nominal fuel savings for FPL's customers is projected to be approximately $4.6 billion.

Regarding system fuel diversity, in 2013 the relative percentages of the total energy supplied by FPL that is generated by natural gas and nuclear, without the EPU project, are projected to be approximately 65% and 20%, respectively. With the EPU project, these projected percentages change to approximately 63% for natural gas and 22% for nuclear. Thus FPL is projected to be less reliant on natural gas, and more reliant upon nuclear energy, by approximately 2% each due to the EPU project.

These percentage changes in system fuel use for a system the size of FPL are significant. This can be demonstrated by looking at the projected amount of energy that will be supplied by the nuclear uprates in 2013. That value is approximately 2.9 million MWh. The forecasted annual energy use per residential customer in 2013 is 13,626 kwh. Therefore, the projected output from the nuclear uprates in 2013 will serve the equivalent of the total annual electrical usage of approximately 209,500 residential customers that year.

The improvement in system fuel diversity from the EPU project 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 2.9 million MWh in 2013 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, the EPU would have saved approximately 29,000,000 mmBTU of natural gas (if all of this energy had been produced by natural gas), or

4,500,000 barrels of oil (if all of this energy had been produced by oil), in 2013. Similar fossil fuel savings would also occur in each succeeding year.

Finally, in regard to the reduction of system CO_2 emissions, the EPU is projected to result in a cumulative reduction over the current license terms of the nuclear units of approximately 30.5 million tons of CO_2. This will be a significant reduction in CO_2 emissions, representing approximately 75% of the total CO_2 emissions from all FPL-owned generating units in 2010. Stated another way, this projected cumulative CO_2 emission reduction from the EPU project is the equivalent of operating FPL's very large system of generating units for 9 months with zero CO_2 emissions.

Q. **You previously mentioned that the EPU project would result in nuclear energy's contribution to FPL's system fuel mix being approximately 22% in 2013. What is nuclear energy's current contribution to FPL's system fuel mix and what is the projected effect of the EPU for the rest of this decade?**

A. This information is presented in Exhibit SRS – 9. As shown on the exhibit, nuclear energy's actual contribution to FPL's system fuel mix in 2010 was 20%. Once the EPU project is completed, following increased scheduled outages prior to 2013 in order to perform the work necessary for the capacity uprates, nuclear energy's contribution to FPL's system fuel mix is projected to remain above the 20% level through the rest of the decade. And, as also shown in the exhibit, nuclear energy's contribution without the EPU project would be projected to be lower than the current 20% contribution from 2013 – on.

Q. What conclusions do you draw from the results of the 2011 feasibility analyses of the EPU project?

A. In regard to these economic feasibility analyses, the EPU is currently projected to be the economic choice in all 7 of the 7 scenarios examined. All of these scenarios assumed the very highest cost value of the projected capital cost range for the project.

In addition, the results of FPL's 2011 analyses show that FPL's customers are projected to significantly benefit from the EPU in regard to system fuel savings, system fuel diversity, and system CO_2 emission reductions once the EPU project is completed.

Furthermore, the EPU project is truly a unique opportunity to offer additional nuclear capacity and energy to FPL's customers. No new sites are required for this additional nuclear capacity, and the construction and permitting times are much less than for a new nuclear unit. Therefore, additional nuclear energy contributions that benefit FPL's customers can be accomplished years earlier through the EPU project than is possible with new nuclear generating units.

Therefore, the EPU project continues to be projected as a solidly cost-effective and valuable capacity and energy addition for FPL's customers. The results of the 2011 feasibility analyses fully support the continuation of the EPU project.

IV. 2011 Feasibility Analyses Results for Turkey Point 6 & 7

Q. **What resource plans were used to perform the 2011 feasibility analyses of Turkey Point 6 & 7?**

A. The two resource plans that were utilized in the 2011 feasibility analyses of Turkey Point 6 & 7 are presented in Exhibit SRS – 10. As shown in this exhibit, the two resource plans are identical through 2021. The resource plans differ in 2022 and 2023 with the Resource Plan with Turkey Point 6 & 7 adding the two 1,100 MW nuclear units, one in 2022 and one in 2023. The Resource Plan without Turkey Point 6 & 7 adds two 1,191 MW CC units, one in 2022 and one in 2023. Both resource plans then add a similar amount of CC filler unit capacity through 2040 (although the timing and number of the filler unit additions differ slightly due to the 182 MW greater amount of capacity added in the two-year period of 2022 and 2023 in the Resource Plan without Turkey Point 6 & 7: 1,191 MW – 1,100 MW = 91 MW x 2 units = 182 MW.)

Q. **What were the results of the 2011 feasibility analyses for Turkey Point 6 & 7?**

A. The results of the 2011 feasibility analyses for Turkey Point 6 & 7 are presented in Exhibit SRS – 11. The breakeven nuclear capital costs in $/kw in 2011$ are presented in Column (6) of this exhibit. The results in Column (6), when compared to FPL's non-binding estimated range of capital costs in 2011$ of $3,483/kw to $5,063/kw, show that the projected breakeven capital costs for Turkey Point 6 & 7 are above this range (i.e., the results are favorable) in 6 of 7 scenarios of fuel cost and environmental compliance cost. In the remaining scenario, which assumes low fuel costs and low environmental compliance costs for each year throughout the analysis period (i.e., for each year through 2060), the projected breakeven capital cost is within the non-binding estimated capital cost range and is at the upper end of this range.

Q. In addition to the results of these breakeven-based economic analyses, did FPL's 2011 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. Just as was done in discussing the EPU project, 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.

Similar to the EPU project discussion, these advantages for the Turkey Point 6 & 7 project will be discussed by using the results from the 2011 feasibility analyses for the Medium Fuel Cost, Env II scenario.

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 the Exhibit SRS – 11, 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, as was the case with the EPU project, 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 $1.07 billion (nominal) in fuel costs. Over the 40-year life of the two new nuclear units assumed (conservatively) for these analyses, the total nominal fuel savings for FPL's customers is projected to be approximately $75 billion (nominal).

Regarding system fuel diversity, in 2024 the relative percentages of the total energy supplied by FPL that is generated by natural gas and nuclear, without Turkey Point 6 & 7, are approximately 72% and 19%, respectively. With Turkey Point 6 & 7, these percentages change to approximately 59% for natural gas and 32% for nuclear. Thus FPL is projected to be less reliant on natural gas, and more reliant upon nuclear energy, by approximately 13% each.

These percentage changes in system fuel use for a system the size of FPL 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 value is approximately 17.7 million MWh. The forecasted annual energy use per residential customer in 2024 is 14,356 kwh. Therefore, the projected output from Turkey Point 6 & 7 in 2024 will serve the equivalent of the total annual electrical usage of approximately 1,232,100 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 would save 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.

Finally, in regard to the reduction of 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 287 million tons of CO_2. This will be a significant reduction in CO_2 emissions, representing approximately 702% of the total CO_2 emissions from all FPL-owned generating units in 2010. 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 generating units for 7 years with zero CO_2 emissions.

Q. **What conclusions do you draw from the results of the 2011 feasibility analyses of Turkey Point 6 & 7?**

A. In regard to these economic feasibility analyses, the Turkey Point 6 & 7 project is clearly projected to be the economic choice in 6 of 7 scenarios examined. In the remaining scenario which assumes low fuel costs and low environmental compliance costs throughout the analysis period, the projected breakeven capital cost is within the non-binding estimated capital costs for the new nuclear units, and is at the upper end of that range.

Therefore, the results of the 2011 feasibility analyses show that Turkey Point 6 & 7 continues to be projected as cost-effective. In addition, the results of FPL's 2011 feasibility analyses show that FPL's customers are projected to significantly benefit from Turkey Point 6 & 7 in regard to system fuel savings, system fuel diversity, and system CO_2 emission reductions once the Turkey Point 6 & 7 units go in-service.

These results indicate that the Turkey Point 6 & 7 units continue to be projected as solidly cost-effective and valuable capacity and energy additions for FPL's customers. These conclusions fully support the feasibility of continuing the Turkey Point 6 & 7 project.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Power Plant Cost Recovery Clause)	DOCKET NO. 110009-EI FILED: JUNE 10, 2011

ERRATA SHEET

TESTIMONY OF STEVEN R. SIM, MAY 2, 2011

PAGE#	LINE #	
Page 16	7	Change "374 MW" to "824 MW"
Page 16	8	Change "5,329 MW" to "5,779 MW"

EXHIBITS OF STEVEN R. SIM, MAY 2, 2011

EXHIBIT #

Replace Exhibit SRS-3 with SRS-3 Revised	Exhibit is replaced due to incorrect projected CO2 compliance cost values for the years 2035 and 2040. The $77/ton value for 2035 is replaced with $98/ton and the $88/ton value for 2040 is replaced with $141/ton.
Replace Exhibit SRS-5 with SRS-5 Revised	Exhibit is replaced because the EPU MW capacity had not been removed from the calculation as stated in the subtitle. The removal of the EPU MW decreases the values in Columns (1), (4), (8), and (9), and increases the resource need (MW) values in Column 10.
Replace Exhibit SRS-8 with SRS-8 Revised	Exhibit is replaced because the EPU capital cost annual revenue requirement calculation was incorrectly carried out past the current license expiration date for two of the four units. The corrected capital cost values are reflected in the new lower EPU cost values in Column (3). The resulting changes (increases) in the projected benefits of the EPU project are reflected in Column (5).

Replace Exhibit SRS-11 with SRS-11 Revised.	Exhibit is replaced because the EPU capital cost annual revenue requirement calculation (that is included in the cost calculations for both the Resource Plan with TP 6 & 7 and the Resource Plan without TP 6 & 7) was incorrectly carried out past the current license expiration date for two of the four units. The corrected EPU capital cost values are reflected in the lower total plan cost values for the two resource plans in Columns (3) and (4). There were no changes in the other columns.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLMENTAL TESTIMONY OF STEVEN R. SIM

DOCKET NO. 110009-EI

JULY 15, 2011

Q. Please state your name and business address.

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. Have you previously filed testimony in this docket?

A. Yes. I provided direct testimony on May 2, 2011, presenting the results of the feasibility analyses for FPL's Extended Power Uprate (EPU) project and Turkey Point 6 & 7 project. This is a supplement to my May 2, 2011 testimony.

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

A. The purpose of this supplement is to provide the Florida Public Service Commission (FPSC), the FPSC Staff, and other parties to this docket with the results of updated feasibility analyses for both the EPU and Turkey Point 6 & 7 projects in which four (4) assumptions have been updated.

Q. Please describe the four assumptions that have been updated.

A. The four assumptions that have been updated include two assumptions that are specific to the EPU project and two assumptions regarding the FPL system as a whole. These four assumptions are:

1. The total number of projected scheduled outage days for FPL's four nuclear units in 2012/2013 in which the remaining EPU construction work will be completed has been increased by 85 days. (The scheduled dates for the outages associated with this increase in the number of outage days have also changed.)
2. FPL's share of the interim MW of increased nuclear capacity for St. Lucie Unit 2 that has resulted from the work performed during the just completed outage at that unit has increased from 17 MW to 29 MW and the start date for this already achieved interim increased capacity has been changed from April 2011 to May 2011.
3. FPL plans to remove its existing Turkey Point Unit 1 (396 Summer MW) as a generation resource beginning in 2016. The unit is now projected to begin serving in a synchronous condenser role in 2016; i.e., in a similar role to the current role of Turkey Point Unit 2.
4. The previous assumption that FPL would be taking an average of 350 MW out of service during all Summer months for scheduled maintenance is no longer FPL's current assumption in its ongoing resource planning work. Consequently, in FPL's current Summer reserve margin calculations, this 350 MW of capacity is no longer assumed to be removed during all Summer months.

As a consequence of these four updated assumptions, FPL has updated its 2011 feasibility analyses for both the EPU and Turkey Point 6 & 7 projects. The results of the updated feasibility analyses are presented in this supplement to my testimony, and continue to show the projects as solidly cost effective.

Q. Are you providing any exhibits with this supplement to your testimony?

A. Yes. As a result of the updated feasibility analyses for both the EPU and Turkey Point 6 & 7 projects, there are a number of changes to the values previously presented in many of the exhibits to my May 2nd testimony. Supplements to those exhibits are attached to this supplement to my testimony and are labeled as "Supplement to Exhibit SRS - _". Supplements to testimony exhibits previously presented include Supplements to Exhibits SRS – 1, 3, 5, and 7 through 11. (Note that the only change in the Supplement to Exhibit SRS – 3 is a correction to two CO_2 projected cost values that were previously presented in an errata sheet.)

In addition, the exhibits for which values have not changed are also presented again for the sake of completeness. These unchanged exhibits continue to be labeled as "Exhibit SRS - _". These include Exhibits SRS – 2, 4, 6, and 12.

Q. In regard to the four updated assumptions, FPL Witness Jones discusses the first and second updated assumptions in the Supplement to his testimony. Please discuss the third and fourth updated assumptions.

A. Both of these updated assumptions are the result of ongoing analyses of the FPL system that typically occur throughout the course of each year. The third updated assumption, the planned removal of Turkey Point Unit 1 as a generating resource and its "conversion" to operation as a synchronous condenser, is based on the results of recent economic analyses which indicate that it will be cost-effective for FPL's customers if Turkey Point Unit 1 is removed as a generating resource and converted to synchronous condenser operation beginning in 2016. Therefore, FPL's current resource planning assumption is that Turkey Point Unit 1 will be removed as a generation resource, and converted to synchronous condenser operation, in 2016.

In regard to the fourth updated assumption (regarding 350 MW of scheduled power plant maintenance during all Summer months), the results of FPL's analyses of the scheduling of power plant maintenance at the time that assumptions needed to be "frozen" for analyses to be completed for the May filing in this docket (and for the April filing of FPL's 2011 Ten Year Site Plan) were such that FPL projected it would be necessary to begin scheduling planned maintenance during all Summer months each year. An estimated average of 350 MW of scheduled maintenance was assumed for FPL's resource planning work in its Summer reserve margin calculations. However, after additional analyses, FPL concluded it could continue to complete the necessary planned maintenance for its generating units without scheduling such maintenance during all Summer months. At that point in time, FPL informed the FPSC of this change through letters which addressed several current dockets.

Q. **Do FPL's updated feasibility analyses of both the EPU and Turkey Point 6 & 7 projects account for all four of these updated assumptions?**

A. Yes. The updated feasibility analyses for both nuclear projects utilize all four of these updated assumptions.

Q. Should the FPSC and other parties to this docket utilize the results of the updated feasibility analyses as representing the most current analyses of the two nuclear projects?

A. Yes.

Q. Please summarize the results of the updated feasibility analyses for the EPU project.

A. The results of the updated feasibility analyses continue to show that the EPU project is solidly cost effective. The results are best summarized by the Supplement to Exhibit SRS – 8. In this supplemental exhibit, the projected total costs of the Plan with the EPU Project presented in Column (3), the projected total costs of the Plan without the EPU Project presented in Column (4), and the projected total cost differences between the two resource plans presented in Column (5) have all changed. As expected, the amounts of the changes vary from one fuel cost/environmental compliance cost scenario to another, and from one resource plan to another.

The changes in the projected total cost differences between the two resource plans shown in Column (5) represent the projected net cumulative present value of revenue requirement (CPVRR) benefits of the EPU project. These current projected net CPVRR benefits of the EPU project, compared to the projected net CPVRR benefits of the EPU project previously presented, can be summarized as being: (i) relatively small in magnitude, and (ii) generally a reduction in the projected net benefits of the EPU project. However, the EPU project continues to be projected as cost-effective in all 7 of 7 fuel cost/environmental compliance cost scenarios.

Q. Please summarize your conclusion based on the results of the updated feasibility analyses for the EPU project.

A. My conclusion remains unchanged from my May testimony. I continue to conclude that the EPU project is a solidly cost-effective capacity and energy option for FPL's customers. In addition to the projected economic benefits, the EPU project will also provide FPL's customers with additional benefits including: increased system fuel diversity, reduced system emissions, reduced losses in FPL's transmission system due to increased capacity from the two Turkey Point nuclear plants, and assistance in addressing the potential imbalance between load and generation in Southeastern Florida due to increased capacity from the two Turkey Point nuclear plants. Furthermore, the EPU project represents a unique opportunity to obtain these advantages of increased firm capacity and baseload nuclear energy approximately a decade earlier than is possible if the increased nuclear capacity and energy is delivered from the construction of new nuclear units.

Q. Please summarize the results of the updated feasibility analyses for the Turkey Point 6 & 7 project.

A. In regard to the Turkey Point 6 & 7 project, the results of the updated feasibility analyses are best summarized by the Supplement to Exhibit SRS – 11. In this supplemental exhibit, the projected total costs of the Plan with Turkey Point 6 & 7 presented in Column (3), the projected total costs of the Plan without Turkey Point 6 & 7 presented in Column (4), and the projected total differences between the two resource plans presented in Column (5) have all changed. As expected, the amounts of the changes vary from one fuel cost/environmental compliance cost scenario to another, and from one resource plan to another.

The changes in the projected total cost differences between the two resource plans shown in Column (5) represent the projected net CPVRR benefits of Turkey Point 6 & 7 absent capital costs for Turkey Point 6 & 7. These current projected net CPVRR benefits of Turkey Point 6 & 7, compared to the projected net CPVRR benefits of Turkey Point 6 & 7 previously presented, can be summarized as being not significantly changed for a given fuel cost/environmental compliance cost scenario. Consequently, the projected breakeven nuclear capital costs presented in Column (6) are not significantly changed from the projected breakeven nuclear capital cost values previously presented.

Therefore, in comparison to the non-binding cost estimates for Turkey Point 6 & 7, the Turkey Point 6 & 7 project continues to be projected as cost-effective in 6 of 7 fuel cost/environmental compliance cost scenarios. In regard to the 7th scenario, which assumes low fuel costs and low environmental compliance costs for all years in the analysis period, the breakeven cost continues to be within the non-binding cost estimate range and at the upper end of that range.

Q. Please summarize your conclusion based on the results of the updated feasibility analyses for the Turkey Point 6 & 7 project.

A. My conclusion remains unchanged from my May testimony. I continue to conclude that Turkey Point 6 & 7 represents a solidly cost-effective capacity and energy option for FPL's customers. In addition to the projected economic benefits, Turkey Point 6 & 7 can provide FPL's customers with additional benefits including: increased system fuel diversity, reduced system emissions, reduced losses in FPL's transmission system due to increased capacity from the two Turkey Point nuclear plants, and assistance in addressing the potential imbalance between load and generation in Southeastern Florida due to increased capacity from the two new Turkey Point nuclear plants. Furthermore, these benefits from increased firm capacity and baseload nuclear energy are projected to be delivered to FPL's customers for at least 40 years.

Q. Does that complete the supplement to your testimony?

A. Yes.

BY MS. CANO:

Q. Are you also sponsoring exhibits to your testimony?

A. Yes.

Q. Do those exhibits consist of SRS-1 through SRS-12 with your May 2nd testimony, including corrections filed with your errata on June 10th; and Supplemental Exhibits SRS-1, 3, 5, and 7 through 11, including corrections filed with your errata on August 4th?

A. Yes.

MS. CANO: Mr. Chairman, I would note that these exhibits have been premarked for identification as Numbers 88 through 99 on Staff's Exhibit List.

CHAIRMAN GRAHAM: Okay.

BY MS. CANO:

Q. Would you please provide a summary of your testimony to the Commission?

A. I'll be glad to.

Good afternoon, Chairman Graham and Commissioners. I present FPL's economic feasibility analyses for the EPU and Turkey Point 6 and 7 projects. FPL's 2011 feasibility analyses of both projects use a multiple forecast/multiple scenario approach that addresses a wide range of potential future fuel and environmental costs. All major assumptions, including fuel costs, environmental compliance costs, and load forecasts have been updated.

FPL then compares the cost to its customers of a generation portfolio that includes the nuclear project being evaluated with a generation portfolio that excludes the nuclear project, and adds, instead, additional natural gas-fired capacity. In both instances the generation portfolio or resource plan that includes the nuclear project is the clear winner in terms of lower revenue requirements for FPL's customers.

Additionally, the result of FPL's 2011 analyses show that both nuclear projects are projected to provide significant benefits to FPL's customers in regard to increased system fuel diversity, reduced system fossil fuel use, firm capacity, and reduced system emissions, a combination of benefits unique to nuclear generation.

The results of FPL's 2011 feasibility analysis in regard to the EPU project can be summarized as follows: The EPU project is projected to be cost-effective in all seven of seven fuel and environmental cost scenarios. FPL's customers are projected to save approximately $4.8 billion nominal in fuel costs over the life of the project. Other projections include that FPL's reliance on natural gas will be reduced buy approximately 2 percent in the first full year of the project, and approximately 30 million tons of CO2 emissions will be eliminated over the life of the project.

In regard to Turkey Point 6 and 7, the results of FPL's feasibility analysis can be summarized as follows: Turkey Point 6 and 7 is projected to be cost-effective in six of seven fuel and environmental cost scenarios, and is break-even in the remaining scenario, which assumes low fuel costs combined with low environmental costs for every year through the year 2063. FPL's customers are projected to save approximately $75 billion nominal in fuel costs over the life of the project. Other projections include that FPL's reliance on natural gas will be reduced by approximately another 13 percent in the first full year of the project, and approximately 288 million tons of CO2 emissions will be eliminated over the life of the project.

In conclusion, Commissioners, both the EPU and Turkey Point 6 and 7 projects are projected to be solidly cost-effective additions for FPL's customers. Therefore, the results of the 2011 feasibility analysis strongly support continuing both nuclear projects.

Thank you.

MS. CANO: FPL tenders the witness for cross.

CHAIRMAN GRAHAM: Okay. Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q. Good afternoon, Doctor Sim.

A. Good afternoon.

Q. As I understand it, FPL employs the technique of comparing the present value of two call streams for -- and let's focus now on the uprate situation -- to compare the net present value of the cost of the uprate project within a generation portfolio with an alternative portfolio that does not include the uprate project, is that correct?

A. Yes, that's correct.

Q. And it is called a CPVRR, that's cumulative present value of revenue requirements?

A. Yes.

Q. That's where you look at a stream of costs over time and discount it back to present day single value, correct?

A. That's correct.

Q. Now, with respect to the Turkey Point 6 and 7, the proposed new units, FPL employs what it calls the break-even analysis, correct, as the feasibility approach for those, for that project?

A. Yes. It's a form of break-even cost analysis that is based upon a CPVRR analysis similar to EPU.

Q. Yes. You anticipated my next question. Again, as I understand it, in the break-even analysis you start with the complete calculation of the net present value of the alternative portfolio, and then I think, as I understand, it's an iterative process where with respect to the new units you enter zero capital costs at first, and then you increase that until you arrive at an equivalent cost factor?

A. Sir, are you referring to the EPU or the Turkey Point 6 and 7?

Q. Turkey Point 6 and 7, the break-even analysis.

A. I don't recall the last part of your question, but let me try to answer it this way. We start with two resource plans, one with Turkey Point 6 and 7 and one without Turkey Point 6 and 7 that has a comparative amount of natural gas-fired capacity instead of Turkey Point 6 and 7. For the plan without Turkey 6 and 7, we do calculate the cumulative present value of revenue requirements for that plan. For the plan with Turkey Point 6 and 7, we do the same thing, but we start with an assumed cost of zero for capital costs for Turkey Point 6 and 7. We come out then with the cumulative present value of revenue requirements for both resource plans. We compare them and get a differential.

Now, the differential certainly favors Turkey Point 6 and 7, because we have assumed, number one, zero capital costs for that resource plan, and it has truly significant fuel and environmental compliance cost savings. What we then do with this cost differential advantage for Turkey Point 6 and 7, we work backwards to see what we could spend on a dollars per kW basis to get to a break-even cost. In other words, how much cost could you spend in order to get to a point where the cumulative present value of revenue requirements for the two resource plans are identical.

Q. Thank you for that description. It's a better job than I did with my question.

Once you arrive at that break-even value, do I understand correctly that gives you the maximum amount in terms of dollars per kW that FPL could spend on the new units and still come in at or below the corresponding cost of the portfolio without the new units?

A. I think the answer to the question is yes, but with the following explanation. We calculate a different break-even cost amount based on each different fuel and environmental compliance cost scenario. The benefits of the project differ, depending upon the fuel cost forecast and the environmental compliance cost forecast. So, therefore, the difference in cumulative present value of revenue requirements changes every time we switch from one such scenario to another. So, therefore, when we move from one fuel and environmental compliance cost scenario to another, there is a different break-even cost.

In addition, when we move from one year's analysis to the next year's analysis, because all of the cost assumptions change from year to year, we come up with different cost differentials, and, therefore, different break-even costs.

Q. Now, earlier you said that the development of the break-even value uses the same type of information that you employ in the CPVRR analysis. Did I understand that correctly?

A. In large part, yes.

Q. Now, in view of the fact that you apply the CPVRR comparison in your feasibility studies for the uprate activities, does it follow that it is within your ability to perform a break-even analysis for that project, as well?

A. I think we are edging into my rebuttal testimony. Could you direct me to where in my direct testimony I refer to break-even costs for the EPU project?

Q. No. My question simply is given your explanation of the methodology used to calculate a break-even analysis, which you do for Turkey Point 6 and 7, and given your acknowledgment that both projects employ CPVRR types of information, do I understand correctly that it is within your ability to perform a break-even analysis for the uprate projects?

A. I would say yes. Not only is it within our ability, but we provide a break-even cost for the EPU project every time we calculate a CPVRR cost difference. For example, take it away from the realm of nuclear and resource plans. If the cost of an object is ten dollars, and the cost of a comparable object is seven dollars, you know the cost differential is three dollars. That three dollars represents the break-even cost as to how much you could either lower the ten dollar cost or raise the seven dollar cost and get to the same point.

So we have, since 2007, provided CPVRR cost differentials for our plan with EPU and a plan without EPU, and that automatically provides a CPVRR break-even cost. Again, it differs from year to year, and it differs for each fuel and environmental compliance cost scenario that we are looking at.

Q. When I asked you if you could perform a break-even analysis for the EPU, I mean the development of a cost expressed in dollars per kW that represents a maximum cost one could spend on the uprate activities and stay at or below the corresponding cost of the alternative. Is that the way you understood my question?

A. I'm sorry, can you repeat the question, please.

Q. Yes. Have you performed a break-even analysis for the EPUs that is expressed in terms of the maximum amount per kW that FPL could spend on the uprate activity and stay at or below the corresponding cost of the alternative portfolio?

A. No, we haven't performed such an analysis, because in our opinion no such analysis is needed. We are calculating the cost differential and we are automatically, as I just explained, calculating a break-even cost on a CPVRR basis.

Q. Back to my original question. Is it within your ability to do so?

MS. CANO: Objection. That question has been asked and answered.

MR. McGLOTHLIN: I disagree with that.

CHAIRMAN GRAHAM: I have to agree with him.

THE WITNESS: I'm sorry, where did we leave out?

BY MR. McGLOTHLIN:

Q. The question is, is it within your ability using the information available to you to perform a break-even value that corresponds to the same type of maximum investment in dollars per kW for the EPU project?

A. Again, it is possible to do so. However, I don't think it is -- it provides any more meaningful information in regard -- over and above the information that we have already provided.

Q. I understand your position on that, Doctor Sim. The question was is it within your ability to do so, should the Commission order it?

A. And I believe I answered yes, it's within our ability.

MR. McGLOTHLIN: That's all I have.

MR. WHITLOCK: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WHITLOCK:

Q. Good evening, Doctor Sim. I just have a few questions for you regarding the Turkey Point 6 and 7 project. As a general matter, when you're performing this quantitative economic feasibility analysis, you would agree with me, wouldn't you, that -- and I believe you have stated as much in your testimony and in your summary -- that you are making any number of projections out a good distance into the future based on certain sources of information, correct?

A. Yes, not just for Turkey Point 6 and 7, but anytime we are evaluating different resource options we are always relying upon a number of forecasts that go out years into the future.

Q. I appreciate that explanation. I'm only asking about Turkey Point 6 and 7.

And certainly others could look at different equally reliable sources and come to vastly different conclusions, could they not?

A. Anything is possible.

Q. So the answer to my question is yes, right?

A. The answer is yes, individuals could come to different conclusions. But I would have to see what those sources of data were before I could provide any sort of judgment as to whether or not they were equally reliable to the sources of date that FPL is using.

Q. And I asked you to assume that they were equally reliable, so the answer to my question would be yes, correct?

A. I think my answer stands.

Q. It's yes?

A. My answer is yes, it is possible to come to a different conclusion, but you are asking me to assume others would come to use a set of reliable data, and I have no basis upon whether to say yes or no to that assumption.

Q. Fair enough. Directing you to the bottom of Page 12, the top of Page 13 of your direct testimony. If you will let me know when you are there.

A. Yes, sir, I'm there.

Q. Okay. At the bottom of 12, I believe in your answer to the question posed on the middle of the page there you reference a prior order of this Commission, and you talk about five informational items that were listed in said order that should be included in FPL's long-term feasibility analysis for Turkey Point 6 and 7, correct?

A. Yes, sir.

Q. And those five are fuel forecast, environmental forecast, break-even costs, capital cost estimates, and sunk costs, correct?

A. That's correct.

Q. Okay. Now, if I could ask you to look at Exhibit SRS-6, and specifically Assumption Number 12.

A. I'm on SRS-6.

Q. Thank you. And on Assumption Number 12 which states, "Previously spent capital costs now excluded," that would be sunk costs, correct?

A. That's correct.

Q. Okay. So is my understanding correct that in performing the economic feasibility analysis for Turkey Point 6 and 7, if you go over to, I guess, Column 2 there, you are excluding $129 million in sunk costs from this analysis, am I correct in that?

A. Yes, the 129 dollars was included in this analysis.

Q. Okay. And why are you excluding sunk costs?

A. We are excluding sunk costs for three reasons. Number one, the well-accepted economic analysis principle is costs that have been spent have no bearing upon the cost to complete a project, and, therefore, should be ignored. Number two, the Commission has issued a rule talking about the costs that we should be including in our feasibility analysis are quite clearly costs to complete, which would exclude costs that have already been expended. And, finally --

Q. I'm sorry, Mr. Sims, if I could interrupt you, please, sir.

MS. CANO: I'm sorry, could the witness finish his answer. He said there were three reasons that he wanted to provide.

MR. WHITLOCK: And he has just listed one and he is talking about a Commission rule that I'm not familiar with, and I would just like -- before he goes onto his third contention, I would like to ask him what rule he is referring to, Mr. Chairman.

THE WITNESS: If I could finish my response, then I will be happy to come back and indicate where that rule is.

CHAIRMAN GRAHAM: Let's find out where that rule is, because he may have an objection for that rule that you are referring to.

THE WITNESS: Very well. If you would give me just a moment.

CHAIRMAN GRAHAM: Sure.

BY MR. WHITLOCK:

Q. You're referring to the cost-recovery clause rule, Doctor Sim?

A. If you would give me just a moment, sir, I will point out where in my testimony that is referenced.

If you would turn, please, to Page 8 on my rebuttal testimony.

Q. I don't have that in front of me, sir.

A. I will give you the rule number, then.

Q. I would appreciate that.

A. It is Rule 25-6.0423(5)(c)5.

Q. So it's your testimony that you believe that the long-term feasibility analysis required by the Commission, that this rule requires you to exclude sunk costs?

A. That is my testimony.

Q. Okay. Now, we just went through --

CHAIRMAN GRAHAM: Hold on a second.

Staff, did you have something?

MR. YOUNG: No, sir.

CHAIRMAN GRAHAM: He initially was finishing the answer to a question. He got through one and a half of them.

Sir, if you would finish those three, and then we will come back.

MR. WHITLOCK: I apologize, Mr. Chairman.

CHAIRMAN GRAHAM: That's all right.

THE WITNESS: Yes, sir.

Very quickly, the three points were a well-accepted economic analysis principle tells you to exclude sunk costs when you look for whether it is advisable to proceed with the project. Number two is this Commission rule that I have just mentioned. Number three is the -- is actually the Commission order from which you extracted, for your question, those five points which specifically separated sunk costs, accounting for sunk costs different from updated cost calculations or cost projections. So those are the three.

CHAIRMAN GRAHAM: Thank you.

Mr. Whitlock.

BY MR. WHITLOCK:

Q. If you included -- assuming you were to include the sunk costs in the CPVRR break-even analysis, how would that affect the outcome of the analysis?

A. Well, first of all, I disagree with the premise. I wouldn't include sunk costs for the reasons just cited. I would be going against the Commission rule, I would be going against the Commission order, and I would be going against a very well-accepted and long-established economic analysis principle.

Q. Okay. With that caveat, you can go ahead and answer my question, then.

A. And if you would repeat your question, please, sir.

Q. If you were to include sunk costs in your quantitative economic analysis of the feasibility of Turkey Point 6 and 7, the nuclear portfolio would look less favorable, wouldn't it?

A. It would look slightly less favorable, I would agree. And let me complete that answer by saying that in all fuel and environmental compliance cost scenarios, Turkey Point 6 and 7 looks quite solidly cost-effective. Therefore, the inclusion of these sunk costs would simply reduce that economic advantage that the Turkey Point 6 and 7 units are now projected to have.

Q. And so you say it comes out favorable in six of seven. If you included sunk costs, what would your best guess be, just off the cuff? How may scenarios would it look favorable in?

A. Six of seven, and would still be break even in the seventh.

Q. Have you performed that analysis?

A. No, I have not.

Q. So that's just your best guess as we sit here?

A. It's an educated estimate, yes.

Q. On Page 14 of your testimony, I believe you're referencing Exhibit SRS-2, which we will look at in a second, but you note that the natural gas costs in 2011 in the medium fuel case is lower than that -- than what it was in the 2010 feasibility analysis, is that correct?

A. I'm sorry, could you repeat the question, please?

Q. Yes. In 2011, the forecast for natural gas is lower compared to -- than what it was in 2010, correct?

A. That's correct.

Q. Okay. And then taking that even a step back, Exhibit SRS-12, which I believe is your testimony from last year's docket, shows that between 2009 and 2010 natural gas prices were also trending downward, correct?

A. I will agree in part, disagree in part. I think if you were to lay out the projected cost for natural gas for the medium fuel cost, you would see that it was higher in some years, lower in other years, comparing '09 with '10.

Q. Looking at SRS-2 in your testimony from this year, Column 3 in the top table there, forecasted natural gas costs, it appears to be trending downward outwards to 2040. Would that be an accurate characterization?

A. In terms of absolute numbers, yes, I would agree. In terms of percentage, the percentage actually doesn't change that much.

Q. So compared to last year, in 2011 there was $1.68 change negative, correct?

A. For the year 2011, that is correct.

Q. And for the year 2040 it is $3.92, correct?

A. That's correct.

Q. So your projections are showing that the price of natural gas would be even less than what they are now in 2040 when FPL claims to -- intended to bring -- claims to have Turkey Point 6 and 7 on-line, correct?

A. No, sir. The cost we are projecting for this year is $4.86; the cost for 2040 is $15.76. I understood your question to be that we are projecting a cost of natural gas will be lower than it is now.

Q. Okay. I was referencing the difference between the 2010 and 2011, the 3.92 number.

A. Again, the difference will grow over time. The approximate percentage by which the natural gas forecast has dropped is ballpark 20, 22 percent for each year. It varies slightly, but that is a pretty good walking around number for the two forecasts.

Q. About 20 percent?

A. Ballpark 20 percent, yes.

Q. And what if you used the low fuel cost forecast, would it be greater than 20 percent?

A. I don't recall. It would surprise me if it was significantly different than that.

Q. Okay. I had a question in regards to your Exhibit SRS-3, specifically, on your forecasted cost of carbon compliance costs. And what I'm trying to understand is you submitted a Supplemental Exhibit

SRS-3, correct?

A. That's correct.

Q. Okay. And the numbers are pretty drastically different there. Can you explain the difference? For example, in 2040 you are showing a $61 negative change between the 2010 feasibility analysis and 2011 feasibility analysis in your original exhibit, whereas in your supplemental you're showing an $8 change. What is that based on?

A. That is based on a data entry error that we corrected with an errata sheet that was filed.

Q. Do you have any other data entry errors?

A. Yes, there have been, which we have indicated in our errata sheets.

Q. Any that haven't been indicated?

A. To my knowledge, no, sir.

Q. Okay. Looking at Exhibit SRS-1, it is projecting, Number 3, that Turkey Point -- the projected fuel savings for FPL's customers over the life of the project is 75 billion in nominal dollars, correct?

A. That is correct.

Q. Now, if you look back at your last year's testimony, Exhibit SRS-12, which is on Page 36 of 46 of that testimony, you had that number at $95 billion, is that correct?

A. Yes, sir. And that can be accounted for by roughly the 20 percent change in decreased natural gas cost forecast.

Q. So between the time we sat here last year and the time we sit here right now, the projected fuel savings for FPL customers have gone down by $20 billion?

A. For that fuel cost, yes, that's correct.

Q. $20 billion. So it would be to fair say the project is trending unfavorably, certainly at least in terms of fuel savings for FPL customers, correct?

A. I would disagree.

Q. Doctor Sim, explain to me how a negative $20 billion change to your customers in fuel savings is not trending unfavorably to them?

A. Well, let me answer it two ways. The project was projected to be solidly cost-effective last year, it is also projected to be solidly cost-effective this year despite the drop in those fuel costs. However, I also take a bigger picture of this for FPL's customers. Lower natural gas costs are good for our customers in general. Significant drops in natural gas costs are beneficial for our customers in terms of their rates and bills. Therefore, even though it may look a bit harmful to this project and reduce its cost-effectiveness somewhat, I believe the question was asked in regard to the perspective of FPL's customers. Our customers will more than benefit in regard to lower electric rates from drops in natural gas costs, even with this project, to the point where I believe our customers will be significantly better off with lower natural gas costs.

Q. Lower natural gas costs do not lead to nuclear generation being more attractive or more cost-effective, do they?

A. Can you clarify your question? Compared to what?

Q. I am stating as a general proposition, the lower the price of natural gas, the less attractive new nuclear generation is; is that an accurate statement?

A. All else equal, the project would look less cost-effective. However, the question is does it still look cost-effective. In other words, it may be less cost-effective than it was, but it is still projected to be significantly cost-effective.

Q. Just $20 billion less?

A. In terms of fuel, yes.

MR. WHITLOCK: Thank you, Doctor Sim.

Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Ms. Kaufman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. Evening, Doctor Sim. I get to bat cleanup here. And I just have a few questions for you. I want to talk to you for a minute about the process that you describe -- we discussed this in your deposition some -- for preparing your feasibility analysis. And one thing that you talk about in your testimony is that when you choose your assumptions that there comes a point in time where you have to freeze them in order to do your analysis, is that correct?

A. Yes, that is generally the process. In order to perform analyses, have the results analyzed, and then prepare written testimony for a filing date, it's necessary for generally some months before the filing date to freeze assumption and get on with the analysis.

Q. And in the case of the hearing that we are at today, I think you told me that generally that happens in your process sometime in the beginning of March?

A. Yes. I believe we discussed in the deposition that I don't have an exact date, but generally early March is a reasonable time in which the assumptions would have been frozen.

Q. And you filed your testimony, your direct testimony that we are discussing here today at the beginning of May, correct?

A. That's correct.

Q. And at that time based on the assumptions that had been frozen sometime in March, correct?

A. Yes.

Q. But then there was a change in some of those assumptions, is that correct?

A. Yes, as evidenced by the supplemental testimony we filed in which we took into account changes in four assumptions.

Q. And in addition, or as part of that also, I believe at the end of May Ms. Cano advised the Commission of one of the assumptions that had changed having to do with summer maintenance, is that correct?

A. That is correct. It was assumption that we would begin to plan scheduled maintenance for our fossil fuel units in the month of August, as well as in the month of January. And that was the assumption, or that was the conclusion at the time in early March by which all the assumptions were frozen to go forward with the analysis. It was one of those items which we continually analyze. And as we went through the weeks and months after we had frozen assumptions, the company came to a different conclusion that we did not now need to begin yet scheduling planned maintenance in the months of August and in January.

Q. And so when you got that additional information and came to that decision, you advised the Commission through a letter, and then you actually supplemented your testimony, did you not?

A. Yes, we supplemented it by changing that assumption and three others.

MS. KAUFMAN: That's all I have. Thank you.

CHAIRMAN GRAHAM: Thank you. That's all the intervenors? Staff.

MR. YOUNG: No questions.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I just have one question that I feel needs to be asked. There has been a lot of discussion with previous witnesses on information being vetted, et cetera. Is there any other information or estimates that you have now that would materially effect your conclusions based on your March information that you had?

THE WITNESS: Commissioner, let me answer the question this way. I know of nothing that would significantly change the outcome of our feasibility analysis. But let me forthcoming that assumptions at a utility are changing constantly. Some of them change almost daily, such as fuel cost forecasts. Others change on a more irregular basis, such as cost and heat rates for, say, combined cycle units. Heat rates for our existing generating units that are taken into account when we do these long-range economic analyses, et cetera. So data is constantly changing at a utility.

What we attempt to do is we wait as long as possible before we freeze assumptions in order to get the most current information available that has been fully vetted and which we can rely upon, and then we begin to perform our feasibility analyses.

It became clear later in the process that there were several assumptions that had changed. I was just asked about one, the 350 megawatts of scheduled maintenance. That assumption alone, if we had decided we would immediately update our feasibility analysis, it would have not changed the results significantly, but it would have changed them in the direction of both the EPU and the Turkey Point 6 & 7 projects being somewhat more cost-effective than what we filed in May. Based on than assumption, or that outcome, we decided that it was probably not significant enough to update the analysis. We would merely bring it up to the Commission when we came before them this time.

However, there were subsequent changes that are in the supplemental testimony of both Mr. Jones and myself regarding a change in the number of outage days for the EPU project, a change in the number of megawatts that we were getting on an interim basis from St. Lucie 2, and the last of the four assumptions was a decision that the company made subsequent to the date of freezing assumptions that it was cost-effective for our customers to take one of our existing fossil fuel units, Turkey Point 1, remove it as a generating unit, and have it operate as a synchronous condenser to provide voltage support for the transmission system.

So, based on the four of those, we decided it was advisable to proceed and redo the analysis, which we provided in supplemental testimony. And the end result of that was that both the EPU -- well, the EPU project is projected to be more cost-effective than it was with the May filing, and there is essentially no change to Turkey Point 6 and 7. All of those changes are essentially a wash for that project.

COMMISSIONER BALBIS: Thank you.

And then I guess to summarize, or ask it in a different way, since the time that you re-performed the analysis based on the revisions to the four assumptions to today, is there anything that has changed significantly, to your knowledge, that would warrant another revision or a substantive change to the conclusions of your feasibility study?

THE WITNESS: Sir, there is nothing I'm aware of that would significantly change the results for either of the nuclear projects.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Redirect.

MS. CANO: No redirect.

CHAIRMAN GRAHAM: Okay. Which exhibits do you want to enter?

MS. CANO: Thank you. I would like to enter what has been marked as Exhibits 88 through 99.

CHAIRMAN GRAHAM: Okay. Are we done with this witness now?

MS. CANO: FPL is, yes.

CHAIRMAN GRAHAM: Thank you, sir. Thanks for your testimony today.

(Exhibit Numbers 88 through 99 admitted into the record.)

CHAIRMAN GRAHAM: We are getting close to the bewitching hour, but if you would bear me for a little while, I want to take a five-minute recess. So we will come back here at 7:00. There are some things that we need to check on, and then we will make some determinations. Thanks.

(Recess.)

CHAIRMAN GRAHAM: Let's reconvene. It is

7:00 o'clock, and I said we were going to shoot for ending the date today at 7:00 o'clock, so we will do that. We are going to reconvene tomorrow at 9:30 a.m. And I believe that we are going to start -- we finished with Witness Sim, and so we will start with Brian Smith tomorrow morning at 9:30. And that all being said, I hope you enjoy the rest of your evening and hope to see y'all here safe tomorrow morning at 9:30. Thank you very much.

Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you.

Just making sure that the chamber will be secured so our stuff can stay here.

CHAIRMAN GRAHAM: Yes.

COMMISSIONER BRISÉ: Thank you.

(The hearing adjourned at 7:04 p.m.)

(REPORTER NOTE: Page 982 inadvertently left blank.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 15th day of August, 2011.

Jane Faurot

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