BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100009-EI

In the Matter of:

NUCLEAR COST RECOVERY CLAUSE.
_______________________________/

VOLUME 2

Pages 169 through 486

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PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN NANCY ARGENZIANO COMMISSIONER LISA POLAK EDGAR COMMISSIONER NATHAN A. SKOP COMMISSIONER ART GRAHAM COMMISSIONER RONALD A. BRISÉ
DATE:	Tuesday, August 24, 2010
TIME:	Commenced at 9:30 a.m. Concluded at 5:50 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
4, 5, 6, 7, 8 and 9			175
188, 189, 190 and 192			175
10, 11, 12 and 13			257
14, 15, 16, 17 and 18			259
193	CR-3 EPU LAR Events Outline	398	
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P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

MR. YOUNG: Staff has no questions.

CHAIRMAN ARGENZIANO: Okay. Is everybody here who needs to be here? Okay, we're on, then.

Commissioner Skop.

COMMISSIONER SKOP: Yes, Madam Chair, thank you. Let me find my document.

Mr. Foster, just a quick question in relation to what has been marked for identification as Exhibit 188.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. And on the graph at the bottom of that page, it shows the estimated rate impact of the Levy capital additions from 2013 through 2024, is that correct?

THE WITNESS: The capital impact, yes, I would agree with that, sir.

COMMISSIONER SKOP: Okay. And then the bottom column -- excuse me, the bottom row is the estimated fuel impact savings, is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. So just following the numbers, taking 2024, for example, the actual residential impact per a thousand kilowatt hours would be the sum of the capital addition plus the fuel savings. So would that be t he net impact in the bill as a whole, not necessarily the bill components, but the bill as a whole would that be the worst-case, it would be approximately $40?

THE WITNESS: Well, I hesitate to say in the worst-case. But I would say -- I would agree that based on our projections right now is that if you assume that in the interim we don't have to build any other plants, if we don't build a nuclear plant, so there are no other capital additions, which I don't believe is a very good assumption, but if that were the assumption, I think to get to your kind of worst-case, and that there are no carbon costs that come into play, I think, yes, I think you've characterized it fairly, sir.

COMMISSIONER SKOP: All right. Let me reframe my question.

THE WITNESS: Sure. Sure. I'm sorry if I'm being picky.

COMMISSIONER SKOP: Under the current projections that would be based on the information that we have before us, the Delta difference would be that number, approximately $40 per thousand kilowatts under today's projections?

THE WITNESS: Yes.

COMMISSIONER SKOP: But.

THE WITNESS: Yes, but. But I think there are other costs, comparison type costs that are not embedded in that, if you will.

COMMISSIONER SKOP: And this chart merely illustrates the potential residential rates that would occur for the time frame in question, but the basis for those rates are 100 percent ownership, and so, therefore, the data on this page, if -- and correct me if I'm wrong, does not include any co-ownership interest that may occur with respect to the two proposed nuclear units, is that correct?

THE WITNESS: You're absolutely right, sir.

COMMISSIONER SKOP: Okay. So I guess with respect to the amounts and this data in relation to co-ownership, you are probably not the appropriate witness to ask in terms of what the probability of co-ownership might be.

THE WITNESS: Certainly not probability of co-ownership, no, sir.

COMMISSIONER SKOP: All right.

Thank you, Madam Chair.

CHAIRMAN ARGENZIANO: Thank you.

Commissioners, any other questions?

Redirect?

MS. HUHTA: No redirect.

CHAIRMAN ARGENZIANO: Okay. Then we will move exhibits.

MS. HUHTA: Progress would move in Thomas G. Foster's Exhibits TGF-1, 2, 3, 4, 5, and 6 as exhibits. On Staff's Comprehensive List, 4, 5, 6, 7, 8, 9.

CHAIRMAN ARGENZIANO: Any objections? Hearing none, so moved.

MS. HUHTA: Thank you.

(Exhibits 4, 5, 6, 7, 8, and 9 admitted into the record.)

CHAIRMAN ARGENZIANO: And now --

MR. REHWINKEL: Madam Chairman, Public Counsel.

CHAIRMAN ARGENZIANO: I'm sorry. There you go.

MR. REHWINKEL: I would move 188, 189, 190, and 192 at this time. I will wait until Mr. Franke gets up to do 191 so we can see about confidential information.

CHAIRMAN ARGENZIANO: Okay. Any objections? Hearing none, so moved.

(Exhibits 188, 189, 190, and 192 admitted into the record.)

CHAIRMAN ARGENZIANO: Go ahead. We're okay?
Ms. Kaufman, you didn't have any exhibits.
Okay. The witness is excused. Thank you.

THE WITNESS: Thank you so much.

MS. HUHTA: Madam Chair, Mr. Foster does not have any rebuttal testimony. We would ask that he be excused from the remainder of the proceeding.

CHAIRMAN ARGENZIANO: Any problems, Commissioners? Okay.

MS. HUHTA: Thank you.

CHAIRMAN ARGENZIANO: Thank you. You're excused. He's like thank you; let me out the door. (Laughter.)

Okay. Our next witness, Gary -- is it Doughty?

MR. WALLS: Gary Doughty.

CHAIRMAN ARGENZIANO: Doughty. I had a friend with the same last name in high school and it was Doughty. Welcome.

THE WITNESS: Thank you.

GARY ROBERT DOUGHTY

was called as a witness on behalf of Progress Energy Florida, Inc., and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WALLS:

Q. Mr. Doughty, will you please introduce yourself to the Commission and provide your business address?

A. My name is Gary Robert Doughty, and my address is 412 White Columns Way, Wilmington, North Carolina.

Q. And have you already been sworn in as a witness today?

A. Yes, I have.

Q. Who do you work for and what is your position?

A. I am with Janus Management Associates, Incorporated, and I am president.

Q. Have you filed Prefiled Direct Testimony and exhibits on March 1, 2010, in this proceeding?

A. Yes, I have.

Q. Do you have a copy with you?

A. Yes, I do.

Q. Do you have any changes to make to your prefiled testimony and exhibits?

A. Yes, one. At Page 39, Line 22, the second two, T-W-O, should read ten, T-E-N. So the phrase should read, "Two of these ten invoices."

Q. And, Mr. Doughty, if I asked you the same questions in your prefiled testimony today, would you give the same answers that are in your prefiled testimony?

A. Yes, I would.

MR. WALLS: We request that the prefiled testimony of Mr. Doughty be entered in the record as read.

CHAIRMAN ARGENZIANO: Show that entered into the record as read. Thank you.

IN RE: NUCLEAR COST RECOVERY CLAUSE

FPSC DOCKET NO. 100009

DIRECT TESTIMONY OF GARY R. DOUGHTY

I. INTRODUCTION AND EXPERIENCE

Q. Please state your name, occupation, and address.

A. My name is Gary R. Doughty. I am President of Janus Management Associates, Inc. My business address is 412 White Columns Way, Wilmington, North Carolina 28411.

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

A. Janus Management Associates, Inc. (Janus) was retained by Progress Energy – Florida (PEF) to review the reasonableness and prudence of project management and project control systems in place to manage the Levy Nuclear Project (LNP) during 2009. PEF is a subsidiary of Progress Energy, Inc. (PGN). PEF is in the process of seeking a combined operating license and siting approval for two AP1000 Advanced Passive nuclear power plants in Levy County, Florida and the necessary electrical baseload transmission facilities.

Q. Do you have any exhibits to your testimony?

A. Yes. I have prepared or assembled the following exhibits to my direct testimony:

- Exhibit No. ___ (GRD-1), Janus Management technical consulting firm services;
- Exhibit No. ___ (GRD-2), resume of Gary R. Doughty;
- Exhibit No. ___ (GRD-3), testimony experience in management prudence reviews;
- Exhibit No. ___ (GRD-4), outage and major capital project experience.

These exhibits are true and correct.

Q. Have you testified before the Florida Public Service Commission (FPSC) in any prior Nuclear Cost Recovery Proceeding regarding the LNP?

A. Yes. I submitted direct and rebuttal testimony to review the reasonableness and prudence of PEF project management and project control systems for the LNP on behalf of PEF in the Nuclear Cost Recovery Clause Docket No. 090009 in March 2009 (direct). I also submitted rebuttal testimony in Docket No. 090009 in August 2009.

The FPSC determined that PEF's project management, contracting, and oversight controls during 2008 were reasonable and prudent for the LNP. (Order No. PSC-09-0783-FOF-EI, issued November 19, 2009)

Q. Please state your professional experience and education.

A. Janus is a management and technical consulting firm providing services to the electric utility industry. See Exhibit No. ___(GRD-1). As president of Janus, I have provided technical support to nuclear utilities through analyses of specific nuclear plant capital construction projects and nuclear plant outage schedule issues. See Exhibit No. ____ (GRD-2). I have led teams that provided support to nuclear utilities in decision analyses for nuclear plant management, nuclear business strategy development, and economic analyses of nuclear plant continued operation versus License Renewal for an additional 20 years of operation or early retirement.

I have also served on independent review teams for utility boards of directors, including: (1) Ameren regarding Callaway Nuclear Power Plant performance issues; and (2) Northeast Utilities (NU) as a member of the Fundamental Cause Assessment Team to determine the reason for the decline of Millstone 1, 2, and 3 performance. I was also a member of the Mixed Oxide Fuel Fabrication Facility Independent Review Team for the Shaw / Areva Board of Governors to review project management, project controls and procurement activities of critical materials for the $4.8 billion facility at the Department of Energy's (DOE) Savannah River Site in South Carolina.

Since 1987, I have led several comprehensive prudence reviews of nuclear power plant project management, electric transmission project management, corporate decision-making, capital program management, and nuclear plant outage management. I have also performed several focused strategic studies for utility senior management and the Electric Power Research Institute.

During late 1986 through 1987, I served as Manager of Industry Relations for the Institute of Nuclear Power Operations (INPO), a private organization dedicated to promoting excellence within the nuclear industry. In this position, I was responsible for administration of INPO's communications, technical policy and informational programs to utility members, suppliers and international participants, related organizations and government agencies.

I have extensive experience in the field of nuclear power plant construction and project management. In 1975 to 1977, I was a startup engineer for the owner utility, Northeast Utilities (NU), of the Millstone 2 nuclear power plant in Waterford, CT. I was responsible for system testing and acceptance during the construction completion phase for several nuclear safety systems, fire protection systems, auxiliary equipment, and balance-of-plant components. During initial plant startup, I was a shift test engineer for the initial criticality, low-power testing and full-power operational certification.

From 1984 to 1986, I was project manager for NU of the Millstone 3 nuclear power plant prudence audit ordered by the Connecticut Department of Public Utility Control. The prudence audit reviewed all aspects of the management, engineering, procurement, construction, startup, project controls, regulatory performance and $4 billion costs of the 1150 megawatt (MW) unit.

While with NU, I was also Manager of Generation Projects for Millstone 2's program for major capital projects, major repairs and initiatives to respond to new regulatory requirements. During a major outage, I was responsible for management of more than $100 million of capital and maintenance projects, including removal of the nuclear thermal shield from the reactor and tube sleeving of the steam generators, both first-time projects for the utility. I managed the overall efforts to prolong the life of the Millstone 2 steam generators. I was responsible for developing annual budgets and schedules for capital and major expense projects to meet operational and regulatory commitments, and I served on the Millstone 2 Nuclear Review Board to review safety-related issues.

I served as a U.S. Navy Officer in the nuclear submarine force. As an officer in the U.S. Navy nuclear submarine force, I was trained in nuclear reactor engineering concepts and qualified to operate and maintain two naval reactor plants.

I have a Bachelor of Engineering degree in Electrical Engineering from Vanderbilt University, and received a MBA from the University of New Haven.

Q. Do you have direct experience related to management prudence evaluations?

A. Yes. I have performed 16 independent reviews regarding the prudence of utility management with respect to nuclear power plant and electric transmission project management and project controls. I have submitted testimony related to some of these independent reviews to nine state public utility commissions. These are identified in Exhibit No. ___ (GRD-3) to my testimony.

I have also performed prudence evaluations of a new nuclear power plant, major capital projects at nuclear power plants and fossil-fired plants, and construction of electric transmission facilities. The new nuclear power plants prudence evaluations in which I was involved are: as a member of the team engaged by the Texas Public Service Commission to review the Comanche Peak nuclear facility in Texas; and as project manager for the owner utility of Millstone 3 to respond to a prudence review by the Connecticut Department of Public Utility Control. The operating nuclear power plants for which I performed independent evaluations of major capital projects and long outages are presented in Exhibit No. ___ (GRD-4). These evaluations do not include the plants already listed in Exhibit No. ___ (GRD-3).

From 2005 to early 2009, Janus performed independent evaluations of Northeast Utilities $3 billion electric transmission infrastructure upgrade. Janus evaluated the siting, design, and construction of electric transmission facilities in Connecticut and Massachusetts.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. Please describe the nature of your testimony in these proceedings.

A. This testimony presents my expert opinion with respect to the reasonableness and prudence of PEF's management decision processes and project management and controls as they relate to the LNP in 2009.

Q. How did you proceed?

A. I started with the reasonableness or prudence standard which is accepted and utilized throughout the electric utility industry. Next, I reviewed PEF's decisions and processes as they relate to the LNP in terms of the processes used and the knowledge reasonably available to PEF managers. The areas that I reviewed were: 1.) Project oversight by the PEF parent board of directors (BOD) and senior management; 2.) Project concept and contract strategy; 3.) Project management; 4.) Project controls; 5.) Risk management; 6.) Policies and procedures; and 7.) Project assessment. I then measured the decisions and processes against the appropriate standard of reasonableness and prudence and arrived at an opinion concerning the reasonableness and prudence of PEF's decisions and processes for the management and control of the LNP.

Q. What methods did you use to review PEF's decisions and processes?

A. I reviewed the LNP documents such as its policies, procedures, schedules, cost estimates, contracts, progress reports, BOD minutes, risk analyses, management oversight reports, regulatory information, audit reports, benchmarking reports, independent assessments, and quality assurance reports. Further, I interviewed managers and key personnel involved in the LNP work, including the Baseload Transmission project, internal audit, project controls, and management.

Q. What standard of reasonableness and prudence did you use in your assessment?

A. In my experience in the electric utility industry, the general standard of reasonableness or prudence is as follows: Prudence is that standard of care which a reasonable utility manager would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made.

The fundamental tenets of utility management prudence include the following:

1. Prudence requires reasonable, not perfect decisions. Nor does prudence require that the single "best" decision be made; a number of different decisions can be prudent.
2. There is a presumption of management prudence.

3. In determining whether a decision was prudently made, only those facts available at the time the decision was made can be considered. Hindsight review is impermissible.
4. A reviewer cannot substitute his judgment for that of the decision maker. The prudence standard recognizes that reasonable people can have honest differences of opinion without one or the other necessarily being imprudent.
5. Prudent decisions made under the set of circumstances at the time a utility investment is made should not be deemed imprudent if conditions change at some later time wherein the investment would not be made.

Q. How did you apply this prudence standard to the management and project controls for the LNP in 2009?

A. As I did in my prior testimony, I applied the prudence standard to a set of general evaluative criteria for a project of the size and complexity of the LNP. These general evaluative criteria for prudent decisions and project controls are: 1.) PEF senior management and the BOD should maintain appropriate involvement, have in place information channels and maintain sufficient oversight to make ongoing critical project decisions; 2.) The LNP project concept and contract strategy should provide the degree of control necessary to protect PEF's investment and be consistent with the magnitude of the project; 3.) The implementation of the decision to build the LNP should be reasonably planned, organized and controlled by PEF to be able to meet project goals for scope, schedule, budget, regulatory, safety, and quality requirements; 4.) The roles and responsibilities of the project team members and the interfaces among the Levy plant and the Levy transmission project team, other PEF functional organizations, the owner's engineers and other contractors, and the consortium should be documented and applied; 5.) The LNP risk management process should identify risks, track identified risks, and provide management with a logical and coherent framework to evaluate, prioritize, and develop courses of action to mitigate or avoid the major project risks; 6.) The LNP should have in place information systems to monitor and report costs, schedule progress, and contractor performance; and to detect threats to meeting project scope, budget or schedule; 7.) The LNP should have in place policies and procedures that define expectations and accountability for work products, identify responsibilities, and serve as training tools for new staff; and 8.) The LNP should have appropriate assessment processes to ensure that regulations, procedures, quality standards, and contractual obligations are met.

Q. Please provide a summary of your testimony.

A. In my opinion, PEF had in place reasonable and prudent LNP project management and project controls in 2009. In 2009, the LNP appropriately transitioned to the Nuclear Plant Development (NPD) organization to manage the Engineering, Procurement, and Construction Agreement (EPC) with Westinghouse Electric Corporation (WEC) and Shaw, Stone, & Webster (SSW) (together the "Consortium").

In 2009, PEF had reasonable and effective senior management oversight of LNP. Senior management oversight was extensive and the BOD was informed and engaged in project decisions. The Levy Program Governance Policy was issued. This policy provides a comprehensive guide for the project with coordinated independent oversight and management.

NPD further enhanced the project risk management process. The project controls in place to develop estimates, monitor budgets and schedules, and control contractors were reasonable. Reporting and performance monitoring and the performance indicators were reasonable.

In 2009, the LNP project management and execution policies and procedures were improved by the NPD and the Project Management Center of Excellence (PMCoE). Specific procedures were prepared to manage the EPC contract. In 2009, PEF performed appropriate project reviews, internal audits, benchmarking, self assessments, and quality assessments (QA) of the LNP.

III. ASSESSMENT OF PEF'S PROJECT MANAGEMENT PROCESSES AND PROJECT CONTROLS FOR THE LNP.

Q. Please describe the status of the LNP at the time of your assessment.

A. The LNP is in the licensing and permitting phase with its Combined Operating License Application (COLA) docketed with the Nuclear Regulatory Commission (NRC). As part of the COLA process, the NRC is preparing the Final Environmental Impact Statement (FEIS) and the Final Safety Evaluation Review (FSER). The State of Florida Department of Environmental Protection and the Army Corps of Engineers are conducting their review of the LNP site wetlands mitigation program. PEF is performing engineering activities to support the licensing and permitting process.

The project work with respect to design, procurement, and construction activities was adjusted in 2009 because of the NRC Limited Work Authorization (LWA) determination. The NRC determined that most of the preconstruction work on the project originally to be completed under a Limited Work Authorization (LWA) would not be authorized until the NRC issues the COL. As a consequence of the NRC decision, the schedule for commercial operation of the Levy units was shifted forward by a minimum of 20 months from the original 2016 plan. This schedule shift also affected the schedule of the Levy Baseload Transmission Project engineering, real estate and construction activities. On May 1, 2009, PEF announced plans to shift the LNP construction schedule a minimum of 20 months. PEF is currently working to develop a new project timeline and project estimate, and is negotiating a contract amendment with the EPC Consortium to shift the LNP schedule.

IV. ASSESSMENT OF SENIOR MANAGEMENT OVERSIGHT.

Q. Was Senior Management involved in oversight and direction of the LNP in 2009?

A. Yes. The Progress Energy BOD received regular updates of key LNP milestones and issues. The BOD established the Nuclear Project Oversight Committee to serve as the primary point of contact for BOD oversight of the construction of new nuclear projects. In 2009, the BOD was kept informed of key information regarding LNP and reviewed and approved LNP strategic direction and financial plans.

The Senior Management Committee (SMC) held Monthly Business Reviews to review project progress and address issues as necessary. Senior management made key decisions and maintained oversight of the LNP through the normal channels of organizational reporting and business planning and budgeting processes. Senior management reorganized the corporate structure to create the Corporate Development Group which includes responsibility for new nuclear construction and various corporate initiatives, such as efforts to expand energy efficiency and renewable energy resources. Senior management also approved the reorganization and staffing of the NPD. The SMC reviewed and approved the 2009 annual project plan, reviewed periodic status reports, and conducted the Monthly Business Review process. Senior management provided oversight of the EPC negotiations for the change order to incorporate the schedule shift.

Additional senior management oversight was provided by the Levy Integrated Nuclear Committee (LINC). In early 2009, prior to the formation of the Corporate Development Department, the senior management oversight functions of LINC were taken over by a similarly comprised group of PEF executive members, chaired by the NPD Vice President, who met at least quarterly to conduct a Levy Program Performance Review (PPR) of program status, risks, business conditions, projects and initiatives required to execute the LNP. PPR members engaged in and provided perspective to ongoing LNP activities based on each member's area of Company expertise. Minutes were maintained and the PEF Board, SMC and BOD were updated as appropriate. The Executive Vice President, Corporate Development was the Levy PPR executive sponsor.

Q. Was the senior management and BOD involvement during 2009 in the LNP prudent?

A. Yes. In my opinion senior management and the BOD maintained a prudent level of involvement regarding the LNP. Senior management kept the BOD informed of the project status, risk factors, costs, project management, and regulatory processes. The BOD was involved in approving key decisions. In 2009, the SMC provided comprehensive oversight of the LNP. Enhanced management coordination and oversight was gained with the creation of Corporate Development and the reorganization of NPD.

V. ASSESSMENT OF PROJECT CONCEPT AND CONTRACT STRATEGY.

Q. Did the LNP project concept and contract strategy continue to provide a prudent degree of control consistent with the magnitude of the LNP in 2009?

A. Yes. In April 2009, the LNP project concept for the LNP was adjusted to address the schedule shift flowing from the determination by the NRC that most of the early site construction work could not be authorized under a LWA, but would have to wait until the NRC issues the COL. PEF adjusted the LNP project concept in 2009 to continue those activities that were necessary to achieve permitting and licensing for the LNP and address the minimum 20-month schedule shift while limiting the pre-construction planning and procurement activities.

NPD was reorganized to integrate the LNP plant with the LNP Baseload Transmission project and consolidate the project controls resources for the full LNP. The Vice President of NPD reports to the Executive Vice President Corporate Development.

NPD manages the EPC Consortium, the joint venture team (JVT) for the COLA, and several contractors for Baseload Transmission, environmental and geologic work. In 2009, the key contract activities focused on the EPC contract to obtain the necessary information to negotiate an amendment for the LNP schedule shift, and on reducing the site engineering work, deferring procurement activities, and closing the contracts for several of the Baseload Transmission project vendors as a result of the schedule shift. The LNP management team prioritized project work for the JVT related to the COLA, the completion of the Site Certification Application (SCA), the SCA commitments, the preparation of the FSER and FEIS, and the Levy site wetlands mitigation studies.

The LNP management team also addressed the Levy Baseload Transmission project work as a result of the schedule shift. Engineering and design work that was in progress was brought to an orderly completion status such that it could be efficiently restarted in the future consistent with the LNP schedule shift. Work was completed in December 2009 on the first phase of the Crystal River Energy Center (CREC) switchyard modifications for the LNP. PEF released most of the contractors including the owner engineer by early December as a result of the schedule shift. In view of the schedule shift, PEF performed a study to analyze cost savings of self-performing the land acquisition program for real estate and right of way activities. The study affirmed the potential cost savings.

PEF managed work on the Levy nuclear project through the EPC contract for work by the Consortium and through contracts with the JVT, owner's engineers, and other contractors using the task order process. The task order approach to authorize work is based on a specific scope that was estimated by the owner engineer and reviewed by the respective PEF project team for technical adequacy and cost. Once released for implementation, the work was monitored by PEF technical personnel and administered by the PEF designated contract representative.

Q. What is your opinion with respect to the 2009 LNP project concept and contract strategy?

A. In my opinion PEF established a reasonable and prudent project concept and contract strategy by establishing and later reorganizing the NPD, consolidating the entire LNP project generation and transmission work groups, and focusing on the work activities to defer major expenditures while addressing the minimum 20-month schedule shift. The 2009 LNP project concept was a prudent approach to managing the project. In my opinion, the 2009 LNP project concept provided reasonable control of project costs while achieving the necessary LNP work given the minimum 20-month schedule shift.

VI. ASSESSMENT OF PROJECT MANAGEMENT.

Q. Please describe the project management for the Levy Nuclear Plant in 2009.

A. In 2009, the Levy project organizations for both the plant and Baseload Transmission began transitioning into the detailed engineering, site preparation, and construction phases.

In January 2009, the Nuclear Projects & Construction Department was restructured and divided. NPD was formed to concentrate leadership focus on the LNP in preparation for entering the site preparation, detailed design and construction planning phase. This move reflected senior management's recognition of the need to align the organization to focus support on new nuclear plant development. From January through April 2009, the NPD organization was headed by Mr. G. Miller, a senior manager, with overall accountability for LNP. Reporting to the General Manager were Licensing, Engineering and Project Controls.

In early 2009, the Levy Baseload Transmission Project group added a General Manager to the existing organization and was recruiting additional members of the Baseload Transmission project team. Reporting to the General Manager were managers in land acquisition, engineering, transmission lines and substations. The Baseload Transmission project had commenced the initial engineering and design work.

In May 2009, the Company reorganized NPD to bring the Levy nuclear plant project together with the Baseload Transmission project. John Elnitsky was named Vice President – NPD. The NPD vice president has overall accountability for both the plant and the associated Baseload Transmission. The revised NPD organization included nuclear plant licensing, engineering, and construction and the Levy Baseload Transmission project team. The change also integrated the project controls and business management functions of the nuclear and transmission project teams. In addition, the Program Coordination and Performance Improvement group was created in NPD to expand the PMCoE functions.

Project management of LNP under the new NPD Vice President, assumed some of the day-to-day LNP management activities of the LINC under a newly formed NPD Program Management Team (PMT). The PMT's responsibilities include: 1.) review program activity including safety and operational readiness; 2.) coordinate necessary inter-departmental program support activity with functional stakeholders; 3.) evaluate, assign and track near term program action items; 4.) review 30-day look ahead program events for involvement, preparation and expected outcome; 5.) review and discuss more detailed program activity with NPD leadership, assign actions and follow-up as needed; and 6.) periodically review PMT structure and charter as the program matures. The meeting frequency was initially set as weekly with program actions to be reviewed, evaluated and recorded during each meeting. During 2009, the NPD Program Action Item list grew to dozens of items categorized as "Deep Dive" topics, NPD action items, long range pending assignments, and "Line of Sight" significant meeting dates extending to year end.

Upon notification by the NRC that the LWA would not be issued earlier than the COL, PEF necessarily deferred work geared to early site construction, deferred procurement in an economical and efficient manner, but maintained the permitting and licensing activities. The NPD was responsible to maintain the licensing and permitting progress. NPD also reviewed the work priorities given the minimum 20-month schedule shift.

Q. Please describe the LNP Baseload Transmission major activities managed in 2009.

A. The Levy Baseload Transmission work in 2009 included completing the evaluation of the Levy Baseload Transmission project on the Florida bulk transmission system; completing route selection and design option studies; developing EHV equipment specifications and EHV system standard design criteria; supporting the SCA and COLA; and completing preliminary design packages on several subprojects.

During the year, the LNP Baseload Transmission team completed system analysis and implemented work on State and Federal licensing, program and project schedules and estimates, staffing and resource plans, project designs and transmission line route selection and land acquisition and permitting activities. The analysis for LNP and its impact on the Florida bulk transmission system was performed in accordance with NRC regulations, Federal Energy Regulatory Commission Large Generation Interconnection rules, existing Reliability Standards, and PEF Interconnection Requirements. The analysis confirmed the scope requirement for the Levy Transmission program.

Key decisions for the Levy Baseload Transmission project made in 2009 included route, conductor and structure selection. Engineering completed specifications for the major EHV equipment and standard design criteria for the proposed EHV system, and preliminary design packages were completed for several projects. Route selection studies identified the best evaluated and preferred rights-of-way using siting criteria incorporating environmental, land use, safety and cost considerations. Wetland surveys were completed on substation sites and preferred transmission rights-of-way. Acquisition of some property proceeded. NPD also completed the first phase engineering work on the EHV work associated with the LNP that was scheduled to be installed in the CREC switchyard in the fall of 2009.

Q. In your opinion, was the project management for the LNP prudent in 2009?

A. Yes. Project management of the LNP was prudent in 2009. The NPD organization established the integrated LNP plant and transmission project teams and other functional organizations, owners' engineers, and contractors under the direction of the NPD Vice President. NPD documented the roles and responsibilities for LNP team members. There accordingly was appropriate project management in place.

The LNP project management team appropriately managed the licensing and permitting efforts and implemented the work necessary to address and evaluate the schedule shift. Given the circumstances of being informed by the NRC that the LWA would not be issued earlier than the COL, PEF's decision to shift the schedule of the project by a minimum of 20 months was prudent. PEF reasonably investigated the likelihood that the NRC LWA position could be modified. PEF continued discussions with the NRC through April 2009 to investigate the potential LWA scope and schedule. When it was clear that the NRC's determination that the excavation and foundation preparation work – originally scheduled to be completed at the same time that PEF was seeking the COLA - would not be authorized until the NRC issued the COL, PEF decided to withdraw the LWA and formally informed the NRC of its decision on May 1, 2009. Without the ability to accomplish the LWA scope requested, PEF reasonably determined that the potential allowed LWA scope was insufficient to maintain the EPC contract project schedule.

In my opinion, PEF implemented this LNP schedule shift prudently. The Company reduced planned 2009 work on both the nuclear plant and the Baseload Transmission project to address the schedule shift. This action reduced 2009 project expenditures while supporting the LNP permitting and licensing effort to achieve approvals of the SCA and COLA. PEF wound down work in an orderly and efficient manner so that it could be resumed without undue loss of the work already performed and performed work that supported the permitting and licensing of the project. This included deferral of procurement activities for those long lead items that could reasonably and economically be deferred, limiting planned staffing additions for the NPD, and reducing the amount of work planned on the Baseload Transmission project.

PEF LNP management took this action on April 30, in accordance with the EPC contract provisions, by issuing a notice of change to the Consortium. PEF also directed the Consortium to prepare schedule and cash flow analyses for schedule shift scenarios to allow PEF to make an informed decision on a contract change order or amendment to be negotiated by PEF and the Consortium in subsequent months. As provided in the EPC contract, PEF negotiated change orders for the requested work for the schedule analyses and long lead procurement activity deferral evaluation work. The change orders were reviewed and approved by both the EPC Consortium and NPD management. NPD monitored the work performed under the change orders in the normal contract administration process and reported this in weekly and monthly reports.

Throughout the remainder of 2009, PEF monitored the EPC Consortium's actions to continue the necessary support work for the AP1000 design certification, the SCA and the COLA; defer procurement of those long lead items that could economically be deferred; and develop schedule and cash flow analyses for various schedule shift scenarios. Other engineering activities continued including geotechnical analyses such as the Levy Site Grout Test completed in May, and the Offset Boring Program completed in the fall of 2009. Work on the blowdown piping environmental assessment, wetlands delineation, and route selection also continued in 2009. Reviews of early site infrastructure and construction engineering documents in the vicinity of the Barge Slip were conducted in May and June. Also, in July, NPD held discussions with the EPC Consortium to start addressing transitioning Levy foundation conceptual design to final design.

Work on the Baseload Transmission project was also adjusted to address the schedule shift. Engineering work no longer immediately necessary to the project was stopped and the existing design work was archived, efforts to engage a land acquisition firm ended, and staffing was reduced. PEF decided to self-manage the land acquisition program after determining that self-management resulted in potential cost-savings. Some transmission work continued to a logical, economical conclusion. The CREC Switchyard phase 1 work installing three EHV switches, that required a unit outage, was completed as planned during the fall 2009

CR3 outage. The Line Route Study was also finalized and approved in October. NPD further identified potential land acquisition needs for wetlands mitigation, State Land easements, and certain transmission ROW and other facilities. This work is expected to be complete in 2010 and some ongoing beyond.

The LNP project management was effective in managing the necessary planning, scoping, siting, and initial engineering work associated with developing the LNP and Levy Baseload Transmission project given the schedule shift that occurred on the project. LNP project management is consistent with Project Management Institute standards and industry practices for nuclear and other major construction projects.

VII. ASSESSMENT OF PROJECT CONTROLS.

Q. Did PEF have in place prudent project controls for the LNP in 2009?

A. Yes. In 2009, PEF initiated enhancements to LNP project controls to meet the challenges expected with the commencement of work by the Consortium under the EPC contract. The established LNP project control processes to report costs, work progress, and schedule performance consistent with the current status of the project and industry standards were reasonable and prudent. When the LNP schedule shift occurred, PEF took reasonable actions to ensure that the project controls systems efficiently and effectively supported the requirements of this period.

Throughout 2009, NPD management continued to make LNP project controls a key and visible element of its management and project implementation process. NPD established a structured approach to establish and enhance the necessary procedures and processes to implement the EPC contract. NPD management has made cost, schedule, and performance monitoring a key element in both its project implementation and oversight process via regular status and assessment meetings and reporting. NPD is incorporating "lessons learned," industry and professional "best practices," and other industry guidelines into its project control process. Further, PEF has in place appropriate contract management processes and procedures to administer the obligations of contractors providing services to the LNP.

Q. How did management make cost and project controls a key and visible element during 2009?

A. NPD management has emphasized quality, cost, schedule, and project management as the continuing theme of its management processes. This emphasis directly communicates and reinforces the importance of the project controls function. Management attention is observed throughout the management and project documents from the executive level down to the contract management and weekly project team meeting level. Management expectations are clearly stated and communicated.

Q. Did PEF reorganize the LNP project controls organization during 2009?

A. Yes. In May 2009, the integration of the Baseload Transmission project into NPD put the Levy Plant and the Baseload Transmission project under one executive. A series of "gear train" work sessions were held to refine the NPD organization including an evaluation of both the Transmission Baseload project controls unit and the NPD project controls unit. The result was a combined organization under the General Manager Corporate Development Business Services.

The project controls organization was staffed with personnel drawn from the prior two existing project control organizations ensuring overall continuity and management by experienced personnel. In addition, a manager of contract administration position was established with the principal responsibility for the EPC contract.

Q. What were the primary LNP project control methods in place in 2009?

A. Building upon the processes established prior to 2009, NPD continued to use several project control methods: 1.) Project plans; 2.) Financial controls (including contract earned value evaluations); 3.) Coordinated corporate budget planning with expenditures as authorized through the Integrated Project Plan process; 4.) Financial cash flow analysis; 5.) Schedules (engineering, contractor, and licensing); 6) Risk management plans; 7.) Performance indicators; and 8.) Vendor performance monitoring (cost, schedule, and performance); and other methods. These project controls are consistent with industry best practices and standards.

To report performance, the NPD prepares a monthly "Nuclear Plant Development Performance Report." This report typically covers such topics as 1.) Safety, cost, schedule issues and activities, including identifying any key issues and risks and providing a look-ahead overview; 2.) Performance data, including key performance indicators (KPIs), integrated cost performance, contract status, contractor cost and schedule performance, scope changes, high risk or critical issues, organization, and staffing; 3.) Significant project decisions; 4.) Self-evaluation results; 5.) Engineering updates; 6.) Licensing updates; 7.) COLA and AP1000 status; and 8.) Public and media interaction information. These topics are consistent with industry practices for project reports on projects of this size and scope.

During 2009, PEF incorporated elements of the Consortium's Levy EPC Monthly Status Report (MSR) into the NPD Performance Report. The EPC Agreement requires the EPC Consortium to provide the report by the 10th of each month. From the issuance of the first MSR in February 2009, PEF took an active role in ensuring this requirement was met and that the report contained timely, useful and accurate information. These efforts resulted in a more informative metric-based document.

In June 2009, NPD began issuing a NPD Weekly Program Report capturing the component "projects" including Levy Licensing (COLA and SCA), Schedule Shift / EPC Negotiations, Transmission, Environmental Mitigation, and Levy State Lands. Other topics were added as appropriate. This report brought increased visibility to the entire Levy program in a consolidated location. These reports are the types of reports I would expect to see in a project such as LNP.

NPD also performs contract management. Contractors are required by each contract to meet specific performance, staffing and reporting requirements consistent with industry standards. Contractor project status reports address, when necessary, issues requiring management attention, quality issues, health and safety issues, teamwork and accountability issues, project budget and invoicing information, scope revisions, budget and schedule performance, monthly cash flow, requests for information, the project schedule, documentation submittals, and work accomplished during the month. These are the types of issues I expect to see in contractor status reports on projects of this size and scope and are consistent with industry practice and standards.

Q. What controls were used for the Levy Baseload Transmission Project in 2009?

A. The project control responsibilities for management of the Baseload Transmission Project included: 1.) real-time schedule and critical path analysis; 2.) cashflow development / assessment with contractor provided data; 3.) key performance indicator development; 4.) change order management; 5.) estimate development and estimate reviews; 6.) contract administration; 7.) contractor schedule and cost review; and 8.) management of project contractors. During early 2009, Baseload Transmission project staff was supported by a financial and business service group with primary responsibilities for cost management and reporting, interface with project controls, financial analysis, budget development and analysis, and project set-up and analysis. Cost estimating and other support functions were provided by Budget Management & Compliance as needed.

Monthly reports were issued summarizing the schedule and financial status of the Baseload Transmission project for senior PEF management. Typical reports addressed: actual, budget and projected expenditures; actual and projected total costs by year - line, substation, and AFUDC; milestone cost history; schedule dates and key events; required third party approvals; issues, impacts, and responses; and the project risk matrix with the likelihood and consequences of identified risk items. In addition, a specific project controls report was issued which detailed month-by month graphs and tables showing individual project actual, budget, variance, and projected costs.

Throughout 2009, the Levy Baseload Transmission project conducted monthly management reviews of program status, cost and schedule updates, near-term activities, program risks and challenges. Project meetings provided information, integration, and coordination between the Project Team and involved PEF Departments. Weekly status reports were also developed by the Levy Baseload Transmission project team showing overall trends, financial information, risks, 90-day look-ahead schedules, percent complete, staffing levels and actions/ issues.

With the integration of the Levy Transmission Baseload project into NPD in mid-2009, the Transmission Baseload Project status was included in the NPD Weekly Program Report. This status report summarized overall LNP project risk, financial performance, changes, milestones, key highlights, schedule and staffing.

Q. What estimating activities occurred during 2009 on the LNP?

A. In March 2009, Burns and Roe issued its report titled, "Review and Validation of the AP-1000 Cost and Schedule." Burns and Roe is a world-wide engineering and construction firm with expertise in nuclear power plants that had been engaged by PEF to provide an independent validation of the LNP nuclear plant estimate. PEF conducted a detailed review of the findings of the report, reviewed the findings with the EPC Consortium, and developed a data base to track related mitigation strategies.

The Levy Baseload Transmission Project conceptual screening estimate was issued in March 2009. The estimate covered the scope of the transmission project (substations, lines, and CREC switches). The estimate was based on high level conceptual designs because preliminary engineering had not been completed for a majority of the subprojects.

After the schedule shift, NPD's primary focus was on reviewing the scenario analyses prepared by the EPC Consortium evaluating the cost impact of the LNP schedule shift. The NPD team began assembling information to analyze options developed by the EPC Consortium.

Q. Was the 2009 LNP cost estimation process prudent?

A. Yes. The cost estimating process for the LNP is reasonable and prudent. The LNP cost estimate was developed in 2008 for the Integrated Project Plan and validated by Burns and Roe in 2009. This integrated estimate was the result of substantial effort by the Levy Plant Project and the Levy Baseload Transmission Project.

PEF identified the scope of the project, including activities to secure permits, authorizations, and approvals; the cost of land and rights of way; the owner-managed project costs; the initial fuel loads; the staffing for startup and commissioning; fees and insurance; escalation and contingencies; and the financing cost. The cost estimates were developed with the input of engineering firms that had similar project knowledge. The estimates were independently reviewed to validate the documentation supporting the costs and to provide an independent assessment of the cost estimate. This process included the elements of a sound estimating process that is consistent with industry and professional standards.

In 2009, the Baseload Transmission project issued the conceptual screening estimate which was a reasonable estimate. The Baseload Transmission project estimate was developed in accordance with professional cost engineering association standards. The estimate utilized available engineering information and provided for management, escalation, real estate, contingency, and other costs. The estimate also incorporated a risk and opportunity analysis.

With the project schedule shift in 2009, PEF has prudently directed the EPC Consortium to develop various scenarios and the resulting cash flows to be able to update the IPP estimate and projection in 2010 when a decision is made on the schedule scenario analyses and further information provided by the EPC Consortium and developed by the Company.

Q. How was the LNP budget monitored in 2009?

A. The budget for LNP work provides a detailed breakdown of responsibility and of accountability. Widely distributed monthly reports tie scope to identified responsible managers and track budgets, actuals and variances. The costs for contractor performed work is reviewed and controlled through the contract administration process.

At the NPD Vice President level there is a monthly budget variance report prepared with input and analysis from the project team. Overall budgets are reviewed by senior management through the Monthly Business Review process. In early 2009, the LINC monitored the overall LNP budget. With the shift of the Levy Baseload Transmission project from the Generation & Transmission Construction (G&TC) into NPD, a single senior executive has sole responsibility for the entire LNP budget.

LNP budget performance is also reviewed by senior management through the management review processes I described earlier in this testimony.

Q. What was PEF's approach to scheduling the LNP in 2009?

A. In early 2009, PEF began to implement and refine the approach developed in 2008 to develop the Integrated Master Plan (IMP). The IMP process was established to ensure that project activities included the schedule activities for the EPC Consortium to support the key project goals and milestones established by PEF management.

The IMP scheduling database included all activities required from COLA development and NRC review, engineering, procurement, fabrication, construction, staffing, training, and startup activities leading to commercial operation. The IMP was developed from the detailed project schedules required for individual LNP contractors including the EPC

Consortium. The IMP also contains schedule information from other sources including supporting PEF business units.

The IMP schedule linked to data from the EPC Consortium that contained approximately ten individual schedules with over 88,000 schedule items. In addition, schedule information from other contractors was also imported. Finally, templates for the AP1000, Toshiba schedule, four procurement schedules, and three construction schedules were established. The IMP scheduling database contained nearly 90,000 individual activities.

With respect to the Baseload Transmission project, the scheduling approach was to develop an overall project schedule to serve as a baseline to assess schedule performance against project milestones. This Level 3 schedule was developed by a dedicated scheduler with extensive experience on large projects worldwide. The schedule was developed to manage and monitor the work of the owner's engineer, the real estate acquisition contractor, and, ultimately the construction program. It was also to be used to monitor and coordinate the work of the various participating PE business units and other project participants. The initial schedule was issued February 16, 2009.

Both the IMP development and the Baseload Transmission schedule used Primavera scheduling software, generally recognized as the best available project scheduling software platform.

After the LWA determination notice and resulting schedule shift, both the LNP plant and the Transmission Baseload schedule approach was adjusted to reflect the change in the level of work anticipated for the remainder of 2009. The LNP plant scheduling effort focused on the permitting and licensing items, and the transmission schedule focused on the near term work at the CREC switchyard.

Q. Was PEF's LNP schedule approach in 2009 reasonable and prudent?

A. Yes. In my opinion, PEF's approach to scheduling is reasonable and prudent. The scheduling process for the Levy nuclear plant anticipated the needs of the project with the signing of EPC contract. The IMP is a reasonable approach to permit owner oversight and monitoring of the LNP project and the EPC Consortium schedule performance.

The Baseload Transmission schedule was reasonable. It was prepared by an experienced scheduler and peer reviewed. The schedule provided a logical sequence of activities and provided the necessary critical path sequence.

The scheduling approach used by the LNP in 2009 is consistent with my experience and industry standards for project schedules of very large projects of similar size and scope. The project is using industry accepted scheduling tools and processes for the incorporation of appropriate data into the schedules.

Q. How did PEF manage LNP contractor performance in 2009?

A. PEF provided oversight of contractors in 2009 as was done in 2008, through direct involvement of LNP technical, management, and project controls staff. LNP personnel provided oversight of contractors by communicating by face-to-face, e-mail, and telephone communications, and by formal and informal meetings. The quality program and audits provided independent reviews of contractor performance. The Company required contractors to provide monthly reports on their accomplishments and their performance under the contract relative to safety, quality, scope, budget, invoicing, schedule, and future work. PEF management reviews were conducted monthly.

Contractors were typically assigned work under a task order process where an assignment was made and an estimate developed by the contractor to complete the work scope. LNP project personnel reviewed the technical scope for responsiveness and the cost for reasonableness. Once approved, the contractor was allowed to proceed. The contractor reported progress against the scope, cost and schedule requirements. Changes in work required similar review and analysis. An impact evaluation was prepared to document the change. Changes were evaluated by technical personnel providing oversight of the work and approved NPD management.

This contract management process to monitor contractor performance was reasonable and prudent.

Q. Did PEF improve oversight of contractors working on the LNP in 2009?

A. Yes. During 2009, PEF improved the oversight of contractors on the LNP by developing and implementing the EPC Implementing Procedures. On the Levy Transmission Project, PEF implemented earned value measurements through the process described in the new PMCoE Project Earned Value Management procedure. These measurements are shown in the Transmission Owner Engineer's Progress (Patrick Energy) presentations. In addition, the Baseload Transmission project improved the Contract Change Notice Process for executing a change notice and authorizing the related work.

Q. Did you find examples of the effectiveness of the Levy Plant project controls?

A. Yes. I found several instances that demonstrate the effectiveness of the LNP project controls. I have described below three significant examples of the prudence and reasonableness of LNP project controls in validating invoices, ensuring proper charging by the EPC Consortium, and internal auditing:

1. The EPC Invoice Validation & Processing procedure was initially used to review and validate 10 EPC Consortium invoices submitted in January, 2009. Two of these ~~two~~ ten invoices with a total value of more than $3M were rejected, and subsequently

withdrawn because the EPC Consortium did not sufficiently demonstrate through proper documentation that the Milestone Payments work had been completed. The EPC Consortium took prompt action to refund the portion of a long-lead equipment invoice (plus associated escalation with interest payments) in which evidence of required milestone completion could not be provided.

2. During review of some EPC Consortium invoices, NPD project controls identified that the actual escalation reported by the January 2009 index was approximately two-percent less than the July 2008 index. PEF worked with the EPC Consortium to adjust the applicable rates as provided for under provisions of the EPC contract. A reduced rate to "true-up" the EPC Consortium invoices for the next six months was agreed upon.

3. On August 3, 2009 the Audit Services Department (ASD) issued the report of the audit it conducted of the LNP EPC agreement. The objective of the audit, in part, was to review the key provisions of the EPC contract to assess the sufficiency of internal policies and procedures developed to support the administration of the EPC contract.

   The ASD rated the overall EPC contract as being "Effective" (the most positive of four ratings). The audit found:

- All invoices sampled were appropriate and had evidence of a detailed review performed by Project Controls.
- Any billing issues identified were resolved in a timely manner.
- In multiple instances Project Controls identified billing issues and appropriately communicated with the Contractor to obtain resolution.

In sum, PEF's LNP project controls in 2009 were reasonable and prudent and they were reasonably and prudently implemented.

VIII. RISK MANAGEMENT.

Q. Did PEF have a reasonable and prudent LNP risk management process in 2009?

A. Yes. Prior to 2009, PEF had in place a reasonable risk management process. In my prior review, I found the LNP risk management process to be a prudent approach to managing a project of this nature and one that is consistent with best practices in the industry and government agencies such as the Department of Energy and Department of Defense. Risks had been identified and assessed and responses were developed. During 2009, the LNP risk management process was prudently enhanced in several ways.

Q. How did PEF improve risk management for the LNP in 2009?

A. In 2009, PEF initiated several enhancements of the LNP risk management program. In January 2009, NPD began updating and re-ranking LNP risks with support provided by the LNP owner-engineer, Worley Parsons. The first enhancement was to transition the NPD risk tool from a regulatory driven focus to an overall EPC execution focus.

Over the period of January through April, an integrated team identified LNP risks and prepared a risk register to track them. Close to 60 risks were mapped "before treatment" and "after treatment" in Risk Maps. The top ten were reported and tracked in the monthly NPD Report. Treatment plans were developed to mitigate the high priority risks.

In March 2009, the PMCoE issued a new risk management standard, "Project Risk Management" PJM-SUBS-00008, which became the corporate standard and is applicable to all projects. This standard builds upon best practices in the industry.

Also, in March 2009, the EPC Consortium submitted the procedures for the Consortium AP1000 Risk and Opportunity Management Plan to NPD management. This document codified the risk assessment procedures for Consortium Risk Management. The Consortium risks consisted of some 250 items that required evaluation. These items dealt with project specific engineering, design, procurement, and construction potential risks. Throughout 2009, NPD reviewed the EPC Consortium risk management process. Meetings were held to ensure accuracy and alignment among the various levels of identified risks and their treatment.

Beginning in August 2009, NPD initiated an effort to implement a more robust risk management process to meet the PMCoE standards established by the new procedure. NPD held a series of meetings to review LNP risks and train both Levy nuclear plant and Baseload Transmission project personnel in the risk process. In September, workshops were held in Raleigh for the nuclear team and Florida for the Baseload Transmission team. A new risk management software tool was researched and purchased to serve as the platform for risk management.

With respect to the Levy Baseload Transmission project, complex work was planned in the CREC switchyard in 2009. A specific risk register was developed for this work. The matrix identified potential risks, probabilities, impact and response strategies.

Q. Was PEF's 2009 risk management process prudent?

A. Yes. PEF improved risk management in 2009. In my opinion, PEF maintained a reasonable risk management process. The LNP risk management process is a prudent approach to managing a project of this nature and one that is consistent with industry and government agency practices.

IX. POLICIES AND PROCEDURES.

Q. Did PEF have in place prudent LNP policies and procedures in 2009?

A. Yes. PEF had in place reasonable and prudent policies and procedures for each function to be accomplished either directly or in support of the LNP. Throughout 2009, overall corporate and LNP specific policies and procedures were revised to improve normal corporate business functions, project management, procurement and contract administration. In addition, NPD made the following specific procedural improvements:

1. Created and revised as needed more than 20 EPC contract oversight procedures for schedule performance oversight, subcontracting, change control, price adjustment, and approval authority for change orders, among others.
2. Developed triggering conditions for development of additional EPC contract oversight procedures.
3. Created or revised PMCoE documents, including procedures for managing scope, cost, earned value, risk, procurement, quality, claims, and lessons learned.

PEF's policies and procedures define expectations and accountability for work product, identify responsibilities, serve as training tools for staff, and provide a program for review and updates. PEF's policies and procedures are consistent with industry standards.

Q. Did NPD have in place the procedures necessary to support effective project management and control of the LNP in 2009?

A. Yes. The underlying basis for managing the Levy Plant and Baseload Transmission projects is the extensive procedural hierarchy by which the Company traditionally managed plant and transmission line projects. PEF established the overall governance policy to guide the construction of the LNP. Also, as noted in my answer above, the PMCoE developed a set of corporate project management procedures to raise the standard of project management. Finally, many Levy EPC procedures were developed to address specific conditions encountered in implementing the EPC contract.

The LNP governance policy is a comprehensive guide for project execution. It established roles and responsibilities based on using internal departmental practices and procedures. The governance procedure provides coordinated management oversight and ensures independent oversight of line organization activities. The governance policy established Cost Performance Indicators (CPIs), Schedule Performance Indicators (SPIs), and COLA performance monitoring. NPD requires vendors to report performance with respect to CPIs, SPIs and other Key Performance Indicators (KPIs). Individualized KPIs were developed for LNP and are reported monthly in the NPD Performance Report.

For transmission activities, the G&TC guideline, Execution of Large Construction Projects and Programs, was used in early 2009. It provided an appropriate set of directives for the Baseload Transmission program team. This procedure identified project management, engineering, environmental support, right-of-way acquisition, project controls and business management support. After the Baseload Transmission project was integrated into NPD, the project management procedures were maintained.

Q. Were PEF's policies and procedures in 2009 prudent?

A. Yes. In my opinion PEF had reasonable and prudent policies and procedures in 2009.

X. PROJECT ASSESSMENT.

Q. Did PEF have in place prudent project assessment mechanisms and processes in 2009?

A. Yes. In 2009, PEF performed reasonable and prudent audits, independent reviews, benchmarking initiatives, and self assessments. The key organizations that perform independent assessments are Internal Audit and Nuclear Quality Assurance (QA). In addition, the line organizations performed self assessments. NPD continued participation in several industry organizations to benchmark the LNP and obtain lessons learned.

Q. Please describe the Internal Audit Project Assessment reviews performed in 2009.

A. The Progress Energy corporate Internal Audit Services Department conducted internal audits on the LNP including: 1.) the Engineering, Procurement, and Construction contract; 2.) the Levy Baseload Transmission Program; and 3.) Florida Nuclear Plant Cost Recovery Rule (NPCRR) Compliance. The EPC contract audit report and the Levy Baseload Transmission Program audit report were provided to the NPD Vice President. The NPCRR Compliance audit was provided to the PEF Controller, the Vice President – Corporate Planning and the PEF Vice President - Finance. Each report identified the audited areas, with an overall opinion and specific observations and recommendations. In consultation with the audited department's management team, each observation and recommendation issue was assigned an action plan. Each action plan identified an owner and a completion date. The audits performed on LNP were responded to and recommendations were acted upon or are scheduled to be completed in 2010.

Q. Please describe the Quality Assurance reviews and audits performed on the LNP in 2009.

A. In 2009, Quality Assurance (QA) reviews and audits were performed for LNP activities in the field with respect to grout activities and boring; supplier audits, and operational readiness. Two grout test audits were to confirm actions had been properly taken as a result of earlier findings and to perform follow up field work. Although minor items were noted, the audits reported compliance with the project QA program.

Two surveillances were performed for the site boring tests, both of which were conducted in September. The audits reported that significant improvement was made by the contractors planning and performing the boring tests.

Comprehensive audits were performed on major suppliers, Shaw Stone and Webster and Westinghouse Electric Company, by joint utility teams. The completed audit reports identify recommendations, management responses, and actions taken as a result of these audits.

Q. Did PEF engage in LNP Self Assessments in 2009?

A. Yes. NPD performed self-assessments of its activities. 2009 LNP self assessments include: document control and records management; financial charging practices; design and license basis control; oversight of design finalization to ensure regulatory compliance; and contractor security requirements. Additionally, benchmarking was done to review activities at the lead AP1000 plant and to review licensing.

Q. What benchmarking for the LNP was performed in 2009?

A. In 2009, PEF continued to work with industry peers in several organizations: NuStart; the AP1000 Owners Group (APOG) / Builders

Group; the Institute of Nuclear Power Operations (INPO) New Plant Executive Group; and the Nuclear Energy Institute New Plant Working Group. Working with these organizations enabled NPD to ensure it had the latest information on issues associated with engineering and licensing associated with COLA development and finalization of the AP1000 design. Further, participation in these organizations led to reducing costs by sharing resources with other utilities planning to utilize the AP1000 reactor technology. The joint efforts also encouraged sharing technical and engineering information.

In addition, NPD participated with the International Atomic Energy Agency exchange visits to China to benchmark their AP1000 program and with an INPO trip to Southern Company's Vogtle AP1000 project.

XII. CONCLUSION: LNP PROJECT MANAGEMENT AND PROJECT CONTROLS EMPLOYED IN 2009 WERE REASONABLE AND PRUDENT.

Q. Are the LNP project management and project controls employed in 2009 reasonable and prudent?

A. Yes. In my opinion PEF had in place throughout 2009 prudent and reasonable processes and an organizational structure to manage the LNP. PEF used reasonable and effective management practices to meet LNP goals for scope, schedule, budget, regulatory, safety, and quality requirements.

Senior management oversight was extensive. The project governance policy further provided a comprehensive guide for the LNP with coordinated independent oversight and management. The NPD is a reasonable management organization which reasonably established stronger business policies and controls. The EPC contract was prudently managed. NPD improved the risk management process consistent with industry best practices. There are reasonable project controls in place to develop schedules and estimates and monitor contractor performance and project expenditures. There was reasonable reporting and performance monitoring, and key performance indicators put in place were reasonable. NPD had in place effective and comprehensive project management and execution policies and procedures. In 2009, these procedures were enhanced and new procedures were developed for managing the EPC. The new project management procedures issued by the PMCoE further enhanced the standards set by Company management. There is extensive use of project reviews, internal audits, benchmarking, self assessments, and QA. As a result, the 2009 LNP project management and project controls were reasonable and prudent.

Q. Does this complete your testimony?

A. Yes.

BY MR. WALLS:

Q. Do you have a summary of your prefiled testimony, Mr. Doughty?

A. Yes, I do.

Q. Will you please summarize your testimony for the Commission?

A. Yes.

Good afternoon, Commissioners. I have over 30 years of experience in the nuclear industry, starting with the United States Navy when I was a naval officer in the Nuclear Submarine Force. In my Direct Testimony, I present my expert opinion with respect to the reasonableness and prudence of Progress Energy Florida's project management, contracting, and oversight controls for the Levy Nuclear Project, and we often phrase that as LNP, in 2009.

After my review and analysis of Progress Energy Florida's project management policies, procedures, processes, and controls, it is my opinion that Progress Energy, their project management, contracting, and oversight controls for LNP in 2009 were reasonable and prudent. And I'm now available to answer questions related to my testimony.

MR. WALLS: We tender Mr. Doughty for cross.

CHAIRMAN ARGENZIANO: Mr. Rehwinkel.

MR. REHWINKEL: Yes, thank you.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q. Good afternoon, Mr. Doughty.

A. Good afternoon.

Q. I didn't mean to slight you in listing the engineers, nuclear engineers. I was talking about the company witnesses.

A. Thank you.

Q. I would ask you what is your understanding of the term reasonable and prudent as you use it in your testimony?

A. Exactly what I say when I talk about prudence with respect to Page 9, beginning about the middle of the page, where it's that standard of care which a reasonable utility manager would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made.

And then what I do is enumerate some tenets with respect to when you evaluate prudence, for instance, that hindsight is prohibited, that there is an assumption or presumption of prudence, and evidence has to be identified and clarified and found to indicate imprudence. And that you can't substitute your judgment for that of the utility manager. There could be an honest difference of opinions in terms of whether or not one course of action is prudent or another. You can have an honest difference of opinion, and there can be many alternatives that could be prudent.

Q. Let me ask you about that alternative. You would agree, would you not, that a utility manager when making a decision that might be subject to review under a reasonable and prudent standard might have a range of decisions that she could make, each of which would be reasonable and prudent, is that correct?

A. Yes.

Q. And in your testimony -- actually in the work you did to support your testimony, did you find that to be the case with respect to what you reviewed for 2009? That meaning that there were ranges of options that the utility managers that you reviewed with Progress Energy chose from?

A. Yes, in the sense that when I looked at project management and project controls, I identified certain standards which are contained in my testimony, and then followed those through with respect to that evaluation. So, frequently, for instance, in the terms of procedures, in reviewing the procedures and having knowledge of nuclear industry procedures, large project procedures, evaluated the characteristics of the procedures that are being employed on the Levy nuclear project with reference to what my team collectively had in mind in terms of procedures for a project of this complexity and magnitude.

Q. Now, it's true, is it not, that your testimony only addresses -- well, let me step back and ask it this way. The scope of work that resulted in your testimony only included Progress Energy's Levy nuclear plant?

A. That's correct.

Q. And you did not, therefore, look at the project related to the CR-3 extended power uprate, is that correct?

A. That is correct.

Q. Was there a reason for that?

A. That was -- the focus was specifically requested by Progress Energy Florida to look at the Levy Nuclear Project.

Q. Okay. In your testimony do you make any reference to customers?

A. I don't recall any specific reference to customers, no.

Q. Okay. If a utility manager has a range of options that are being evaluated for reasonableness and prudence, and one of the options is more beneficial -- let me strike that and ask it this way.

If a utility manager has a range of options in his decision-making, each of which would meet the reasonableness and prudence standard in your testimony, and one of those options is more beneficial to the customers, does that utility manager have any obligation to choose that decision over the other decisions?

A. I'm not sure I can answer your hypothetical because I don't think there is enough facts. You have to look at the entirety of the information, the totality of the information. And how does one determine what -- whether that is a greater benefit or not? I have to deal with a specific.

Q. Okay. Well, the purpose of your testimony is to validate the decision-making of Progress Energy such that its decisions qualify for cost-recovery under the reasonableness and prudence standards of the statute, isn't that correct?

A. Yes, for 2009.

Q. Okay. Now, are you -- I noticed in your body of work that you have done quite a lot of work on behalf of public service commissions around the country, is that correct?

A. Both. Actually, our team, my team, has done quite a large number of major nuclear projects when the first wave of later nuclear projects were coming on line. I was involved both on the company side and on the Commission side.

Q. Okay. So you understand the purpose of -- well, let me ask it this way. Isn't it true that the advanced cost-recovery provisions of the statute that governs this proceeding are relatively new with respect to utility ratemaking?

A. Yes. Can I clarify my response to the previous question?

Q. Sure.

A. One of the things I do understand with respect to being an expert witness is I'm not on somebody's side. I am on, in essence, the Commission's side to identify the true facts and give my expert opinion. So it's not in terms of choosing sides, but rather independence. So could you repeat your question?

Q. Well, sure. I mean, what you just told me is much like what Dr. Jacobs does for the Georgia Public Service Commission. He's an independent monitor of the construction project, isn't that fair?

A. Right, and I have served that role.

Q. Okay. So in serving that role, you do understand that the public service commissions that you would work for are charged with looking out, in part, for the interests of the customers of the utilities they regulate, isn't that true?

A. Yes, that true.

Q. Okay. So the question I asked that you said yes to, but you may -- you wanted to talk about the prior question, so I want to ask it again. Is the advanced recovery provisions of the nuclear cost-recovery rule and statute that govern this proceeding are relatively new in terms of utility ratemaking, isn't that correct?

A. Yes, to a certain extent. Certainly in the new nuclear power field, but in many instances utility commissions are reviewing decisions at the time the utility raises it as a potential capital investment. So it's more prospective or even current prudence review rather than what the first wave of nuclear plants had and coal plants, too, and hydro facilities, which was a retrospective, after the project had already been completed and was ready to be placed in service, and, therefore, in rates.

Q. And until the advanced recovery statutes were authorized in a handful of states, isn't it true that virtually every state only allowed cost-recovery for major rate base additions only after those additions contributed to the generation of electricity?

A. To the extent of my knowledge, and I'm not --

I don't know if this is a universal -- capable of being a universal response, but to the best of my knowledge that was the case, certainly as I was describing in the 1970s and '80s.

Q. Okay. So what's new about the statute that governs this proceeding is that cost-recovery is allowed in advance, many years in advance of the proposed units generating any electricity, correct?

A. As I understand the statute, and the Nuclear Cost-Recovery Clause, that is what's happening, because you have established in the state of Florida this statute by law to permit recovery of those type of expenditures that are covered by the law.

Q. And the Florida Public Service Commission is charged under the law with, among other things, making determinations about the reasonableness and prudence of the utility's decision-making as these advanced -- as these expenditures occur well in advance of the generation of any electricity, isn't that correct?

MR. WALLS: I'm going to object to this line of questioning. Mr. Doughty I'm not sure is an expert on the Florida statute and rule. He had a particular job to do and came in and testified to the project management controls and oversight controls, and it seems like he is being asked to opine about the statute and rule.

CHAIRMAN ARGENZIANO: Mr. Rehwinkel.

MR. REHWINKEL: Madam Chairman, my questions go to the nature and the quality of the reasonableness and prudence opinion that he's rendering here. And I have a line of questions that is about to get to an ultimate point, and actually I touched on it earlier, which is the Public Service Commission is charged with looking after the customers. And part of this decision-making that he is evaluating, I want to find out whether qualitatively there is any view with respect to the customers' interests. So I'm trying to test the nature of his opinions that he's offering, specifically on reasonableness and prudence.

CHAIRMAN ARGENZIANO: Can you rephrase without asking him his opinion of the statute or his knowledge of the statute?

MR. REHWINKEL: Well, I think he already acknowledged that his reasonableness and prudence opinions are given to meet the standards that are in this statute.

CHAIRMAN ARGENZIANO: Ms. Helton.

MR. REHWINKEL: I'm definitely not looking for his legal opinion about the statute.

CHAIRMAN ARGENZIANO: Okay.

MS. HELTON: As I understand the witness' testimony, and please correct me, Mr. Walls, if I'm not hearing this correctly, he is here to give an opinion with respect to prudence as prudence is contemplated in Chapter 366, is that correct?

MR. WALLS: But on project management controls and oversight.

MS. HELTON: With one specific, I guess, narrow type of expenses that could be deemed prudent under the statute, is that what your point is?

MR. WALLS: My point is that the Commission has established an issue in this proceeding each year, which is whether the company's project management controls and oversight on the project are reasonable and prudent, and that's what Mr. Doughty is coming in as an independent expert to review the project management policies and procedures and implementation of those, and say whether those are reasonable and prudent.

He is not looking at the costs that are being requested and recovered, and he's not opining on any of the costs. He is specifically looking at did the company have prudent project management policies and procedures in place, and did they follow those in 2009, and that's what he is opining on.

MS. HELTON: Madam Chairman, I'm sorry, I'm going to have to have Mr. Rehwinkel repeat the question.

CHAIRMAN ARGENZIANO: Let's do that.

MR. REHWINKEL: Why don't I do this; why don't I ask a different question?

MS. HELTON: Okay.

CHAIRMAN ARGENZIANO: We can do that, too.

BY MR. REHWINKEL:

Q. Mr. Doughty, let me ask you again about the range of reasonable decisions that you might, or the range of decisions that might be subject to an evaluation for reasonableness and prudence. And is it your testimony that the customers' interests should not be given any greater weight in evaluating which of a range of possible options that the company might have should be chosen as long as all of the options would fit the reasonableness and prudence standard that is in your testimony on Page 9?

A. But my testimony is with regard to the project management and project controls that were in place for the project. So it's a narrow focus, I agree, but it is the focus. I haven't looked at any other types of decisions other than those that apply to did the company reasonably have in place organizational processes, procedures, policies, and not only implement them, but carry through on them and have a feedback loop to check them, as an example.

Q. So is it your testimony that the customers interests have -- the customers have no interest in those project controls and management practices?

A. The customers would have an interest in the sense of if they were reasonable and prudent policies, procedures, project management decisions and activities would yield, you know, a reasonable implementation of the project.

Q. Is it fair to say that as long as a utility manager makes a reasonable or prudent decision within the range of options that he has, that whether one decision favors the customers' interests more than the other, it does not matter for purposes of the Public Service Commission's determination?

A. I don't think I understand your question, because I haven't looked at that. I looked at project management and project controls on the Levy Nuclear Project.

Q. Okay. Now, you did not evaluate the decision by the company in 2009 with respect to -- the decision-making by the company with respect to which of the options they might choose with respect to the in-service date of the project, is that correct?

A. If you are talking about the decision that they made in March/April of 2010, that's correct. I did not look at that. What I looked at was the collection of information and the actions that were taken during 2009 with respect to project management and project controls.

Q. Did any of that cover the decision-making that led up to the 2010 decision to select the option that they are proposing in this case?

A. In the sense that I looked at and reported on the fact that they had requested information from both Westinghouse Electric Corporation and Shaw, Stone and Webster with regard to providing them information for a schedule shift of greater than the 20 months that was indicated, yes, and I spoke with various personnel with respect to that effort that was going on then, which was the data collection and the beginning of the analysis.

Q. On that point --

MR. REHWINKEL: And, Madam Chairman, I have some questions based -- with some documents, but the company is reviewing those documents to try to winnow down confidentiality, or at least to identify it in the documents. And if I could work with the company on this, I don't need to ask Mr. Doughty questions about the documents, I just need to authenticate the documents with him. So what I would like to do is to try to ask him about these documents, and if we need to produce the documents we will. Otherwise, I will take them up with the other witnesses I intended them with.

CHAIRMAN ARGENZIANO: Okay.

BY MR. REHWINKEL:

Q. Mr. Doughty, you mentioned interviews, and is it correct that you interviewed John Elnitsky and Sue Hardison as part of your work?

A. Yes, it is.

CHAIRMAN ARGENZIANO: Mr. Rehwinkel, hang on one second.

MR. WALLS: We are not imposing any objections on authenticity or grounds, so.

CHAIRMAN ARGENZIANO: Okay.

MR. REHWINKEL: I understand. I just need to go through this.

BY MR. REHWINKEL:

Q. And you would have generated notes from those interviews, is that correct?

A. That is correct. They were notes as taken, essentially.

Q. Now, did you take these or did members of your team do these?

A. All of the above; that is, that there were -- all of us took notes and accumulated them into the single set of notes.

Q. Were they recorded or just these are handwritten notes that you typed up?

A. Handwritten, typed up.

Q. Okay. All right. Now, when you took these notes and generated the documents that the company provided to the staff and to the Public Counsel, were the subjects of the interviews, did they make any corrections or provide any further input to the draft that you produced?

A. Which draft? Or what draft are you talking about?

Q. I'm looking at a draft of Sue Hardison's interview on February 9, 2010?

A. No, they did not.

Q. Okay. Were they offered that opportunity?

A. No.

CHAIRMAN ARGENZIANO: Excuse me, Mr. Rehwinkel.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

To Mr. Rehwinkel, with respect to the documents in question, I think that you indicated you did not have any questions regarding the documents, but it appears that you are laying a predicate or a foundation for authenticating the documents, is that correct? Because I think I heard Progress -- and the reason I ask, I thought I heard Progress say that they are not contesting to the authenticity of the documents, so I'm wondering if it is necessary to lay that foundation.

MR. REHWINKEL: Well, it is not as to the documents itself, but if I ask a subsequent witness did you say that, I want to make sure that there is not a dispute about that.

COMMISSIONER SKOP: Very well. Thank you.

BY MR. REHWINKEL:

Q. And what about with Mr. Elnitsky, would he have been offered the opportunity to review the notes?

A. No.

Q. Okay. Is there any doubt in your mind about the accuracy of the statements that are contained in the notes for Mr. Elnitsky and Ms. Hardison?

A. As labeled on the top, they are for discussion purposes only, because they are not a recordation of the actual questions and answers. So there may be some items that were not necessarily part of the focus, but were broader in terms and we may not have gotten exactly right.

Q. On Page 24 of your testimony, could you turn to that?

A. Page 24?

Q. Yes, sir.

A. I'm there.

Q. Okay. Actually, this starts on Page 23 at the bottom. You offered testimony about the implementation of the LNP schedule shift, and you testified that the company reduced planned 2009 work on both the nuclear plant and the base load transmission project to address the schedule shift, do you see that?

A. Yes.

Q. And you continue on to the top of Page 24, all the way down to Line 6. You say, "This included deferral of procurement activities for those long lead items that could reasonably and economically be deferred, limited planned staffing additions for the NPD, and reducing the amount of work planned for the base load transmission project." Do you see that?

A. Yes.

Q. Did you review a program within the company in 2009 called operational readiness project?

A. Not that I recall.

Q. Okay. Do you recall reviewing any projects of the company that caused them to -- whereby they intended to hire and train engineers and other operating personnel for the projected Levy plant?

A. I was aware of the staffing plans that were anticipated for the Levy Nuclear Project, but I did not read anything beyond that. It was primarily in discussion with Mr. Miller when we were doing the 2008 review in early 2009.

Q. Okay. Did you review the staff audit report that was produced in this docket?

A. I've reviewed staff audit reports, I think three of them. I don't know the exact dates. One would have been for 2008. I think one came out in the middle of 2009, and the third one may have just recently come out or came out as a draft.

Q. I'm asking about the one that's attached to the testimony of the staff witnesses in this case. Did you review that document?

A. Not while I was doing this review, no.

Q. Did you review it after that?

A. If it's the one that came out in 2010 --

Q. Yes.

A. -- I have recently reviewed that.

Q. Okay. Do you recall the section in there about an operational readiness group?

A. No.

Q. Okay. So if there was -- I guess by definition, you did not review that effort by the company with respect to whether they limited planned staffing additions relative to that project, is that correct?

A. Are you reading from my testimony on a particular line?

Q. Yes. Again, Line 6 through 9 on Page 24.

A. The planned staffing additions had to do with the project team. The organization that existed prior to the signing of the engineer procured construct contract was adjusted, and there were plans to add significant numbers of staff in the early part of 2009 because of the anticipated start up of work both by the consortium -- well, by the consortium and the other work that was going on by other contractors. So that's what I'm talking about is the project management staff, the project control staff that was anticipated to be added to and then was not.

Q. Okay. You didn't find anything in your work where the company did anything wrong or that wasn't prudent, isn't that correct?

A. I did not find any imprudent or wrong activity by the company that would have led me to change my opinion of the reasonableness of the project management and project controls in place.

Q. Okay. And the project management activities that you evaluated, would the company's actions with respect to those activities have any influence or affect on the enterprise risks that would impact the Levy Nuclear Project?

A. Would you restate your question or --

Q. Yes. The project management activities that you evaluated for prudence, none of those activities would have any impact or influence upon enterprise risks that might impact the Levy Nuclear Project, isn't that correct?

A. No. In reviewing project management and project risk, a reasonably run project will reduce risk unless it's totally external. For instance, we were talking earlier with another witness with regard to carbon taxes or cap and trade legislation which is beyond the control of the company, so an externality, if you will.

Q. Well, my question was as to enterprise risks which are external, aren't they?

A. Not necessarily. But for the most part, the ones that people talk about are external.

Q. Okay. But would you agree with the definition that enterprise risks are those that are outside the control of the company?

A. Not necessarily. But for the most part, many enterprise risks are outside the ability of the company to control.

MR. REHWINKEL: Okay. Thank you, Mr. Doughty; that is all the questions I have.

Thank you.

CHAIRMAN ARGENZIANO: Thank you.

Commissioners, any questions?

COMMISSIONER SKOP: I have a few.

CHAIRMAN ARGENZIANO: Commissioner Skop.

COMMISSIONER SKOP: Do you want to take the other intervenors who have any questions before?

CHAIRMAN ARGENZIANO: Well, did you want to ask your question now?

COMMISSIONER SKOP: I can wait until the intervenors.

CHAIRMAN ARGENZIANO: Okay. Well, then let's proceed.

MR. BREW: Thanks.

CROSS EXAMINATION

BY MR. BREW:

Q. Good rod afternoon, Mr. Doughty.

A. Good afternoon.

Q. Mr. Doughty, were you asked to evaluate the enterprise risks facing the company?

A. No.

Q. Okay. Were you asked to evaluate the company's evaluation of its going forward options with respect to Levy that it announced in its April 30th testimony?

A. I'm sorry, I didn't hear the last part of your question.

Q. The going-forward options that the company described in its April 30 testimony, were you asked to evaluate those options?

A. No, sir.

MR. BREW: That's all I have. Thanks.

CHAIRMAN ARGENZIANO: Ms. Kaufman.

MS. KAUFMAN: Thank you, Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. Good afternoon, Mr. Doughty. I just really have one area that I want to talk to you about, and you addressed this with Mr. Rehwinkel.

On Page 9 of your testimony, you talk about the standard of reasonableness --

A. Just a second.

Q. I'm sorry.

A. Okay. Page 9.

Q. Okay. Toward the bottom you talked about the standard of reasonableness and prudence that you used in your assessment.

A. Yes.

Q. And one of the tenets, I guess, of your assessment is the one that appears on Line 23, that there is a presumption of management prudence?

A. Yes.

Q. Would you agree with me that in a proceeding like this where the company is asking to collect money or change rates to the ratepayers that the burden of proof always lies with the utility?

A. No, I would not agree.

Q. Okay. Have you review -- I know that you are not an attorney, but in the course of your review here and your work, have you taken a look at any Public Service Commission orders in regard to how the Commission looks at presumptions and burdens of proof?

A. Are we talking about the Florida Commission?

Q. Yes, sir, the Florida Commission.

A. No, I haven't. But in my experience in dealing with prudence since 1984, it's pretty well established within other jurisdictions that there is a presumption of prudence, and in terms of many articles that I have read. And the fundamental tenets that I identify here are a collection. The first and foremost is the National Regulatory Research Institute, which issued a significant paper back in about the 1985 to '88 time frame from Ohio State University, which identified some of these tenets, and then subsequent to that significant either public service commission decisions, or if they were elevated to the court to where those were recorded, the outcome of that court, those court decisions.

Q. You are not referring to Florida decisions, though?

A. No, ma'am.

MS. KAUFMAN: Madam Chairman, I have an exhibit. It's actually an order, but I will pass it out so everybody will have reference to it.

CHAIRMAN ARGENZIANO: It should be numbered 193.

MS. HELTON: Madam Chairman, my recommendation would be that we just take official notice of the order. I don't think it's necessary to mark it as an exhibit.

CHAIRMAN ARGENZIANO: Okay. Very good.

MS. KAUFMAN: That's fine.

For the record, it is Order Number PSC-09-0024.

CHAIRMAN ARGENZIANO: Thank you.

BY MS. KAUFMAN:

Q. Mr. Doughty, you have Order Number 09-0024 in front of you, correct?

A. Yes, I do.

Q. Okay. And I'll represent to you, and I think your counsel will agree, that this is an order from the annual fuel adjustment proceedings in which the Commission sets the fuel adjustment factor, and they set that annually.

If you take a look at Page 12, which I've got tabbed for you, and I'm going to be looking at the top paragraph there. And, again, I represent to you that in this case the Commission was looking at making a prudence determination about some activities of Florida Power and Light. Would you mind reading that highlighted sentence?

A. The highlighted sentence that's in yellow that's in about the middle of the first paragraph?

Q. Yes, sir.

A. It has been well-established both by us and the state's courts that the burden of proof lies with the utility who is seeking a rate change.

Q. So would you agree with me that this is the standard that the Commission typically applies to a utility seeking a rate change in Florida?

A. I don't know if I can agree with you. I don't have enough knowledge to be able to agree or disagree, but I do understand what I read there.

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

CHAIRMAN ARGENZIANO: Thank you.

MR. DAVIS: None from SACE. Thank you.

CHAIRMAN ARGENZIANO: Okay. Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

Just a few questions, Mr. Doughty. On Page 3 of your prefiled testimony -- or, excuse me, Page 7 of your prefiled testimony.

THE WITNESS: Page 7?

COMMISSIONER SKOP: Yes, sir.

THE WITNESS: Yes.

COMMISSIONER SKOP: On Lines 1 through 6 you identify that you've performed 16 independent reviews regarding the prudency of utility management with respect to nuclear power plants and submitted testimony regarding the reviews to nine public utility commissions. With respect to the exhibit that's marked in your prefiled testimony as GRD-3, and I'll give you a second to turn to that.

THE WITNESS: Okay.

COMMISSIONER SKOP: With respect to each of those management prudence reviews that you conducted for those commissions listed there, were there any instances where you found management to be imprudent or actions to be imprudent?

THE WITNESS: Yes, Commissioner. In items under Maryland, Item Number 1, and for Massachusetts, the Pilgrim outage, we found imprudence in management of a long outage which went longer than was reasonable, in our opinion. And I can't quantify dollars, but it was in terms of days in several instances in the Pilgrim case, and in at least two instances in the Calvert Cliffs case.

COMMISSIONER SKOP: Okay. And you have had, based on your biographical information, substantial nuclear experience working at Millstone units up in Connecticut and various other things, as well as your nuclear submarine experience, is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. In relation to the information that you were asked to review in this proceeding, it's my understanding from your testimony that it was strictly limited to the Levy 1 and 2 nuclear units and not the CR-3 EPU LAR, is that correct?

THE WITNESS: That's correct.

COMMISSIONER SKOP: Okay. On Page 11 of your prefiled testimony, you indicated that in your professional opinion that Progress had reasonable and prudent LNP, or -- yes, LNP project management -- I mean project management and project controls in place in 2009, and that was because basically they had taken appropriate steps and had appropriate controls in place to identify not only risk management, but risk mitigation on contractual issues and other things that you identified on Page 12, is that correct?

THE WITNESS: Yes, sir. And that they had in place policies and procedures to guide personnel who were participants in the project. Cost controls, contract controls on the vendors that were involved in the project.

COMMISSIONER SKOP: Okay. And then, finally, on Page 23 of your prefiled testimony, you discuss the circumstances regarding the fact that the NRC denied the LWA and indicated they would not issue it prior to the COL, is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. And in this case is it correct to understand, based on the data that you have reviewed, that Progress reasonably thought at the time that the original schedule was created that pursuant to the NRC's streamlined licensing process of a new that the LAW would be granted to allow limited work authorization prior to the issuance of COL?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And when that changed, you know, that was not reasonably foreseeable by Progress, is that correct, because Progress doesn't control what the NRC does?

THE WITNESS: That is correct. And, in fact, in December of 2008, there was an indication here in Florida by an NRC representative that there was an expectation of receiving the LWA on the schedule that they were anticipating.

COMMISSIONER SKOP: Okay. So on Page 23 of your prefiled testimony, Lines 18 through 20, you indicated without the ability to accomplish the LWA scope requested that PEF had to readjust its schedule, and that's primarily what drove that schedule shift for the LWA to the extent that they had anticipated on being able to do work in advance of the COL that the NRC subsequently told them they could not perform, is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: All right. Thank you, Madam Chair.

Thank you.

CHAIRMAN ARGENZIANO: Staff.

MR. YOUNG: Staff has no questions.

CHAIRMAN ARGENZIANO: Progress, redirect?

MR. WALLS: No redirect.

CHAIRMAN ARGENZIANO: Okay. Let's move exhibits.

MR. WALLS: Yes. We would move Exhibits GRD-1, 2, 3, and 4, which are identified in the Staff Comprehensive Exhibit as Exhibits 10, 11, 12, and 13.

CHAIRMAN ARGENZIANO: Any objections? Hearing none, so moved.

(Exhibits 10, 11, 12, and 13 admitted into the record.)

CHAIRMAN ARGENZIANO: Mr. Rehwinkel?

Any other questions, Commissioners?

You're excused. Thank you.

THE WITNESS: Thank you.

MR. REHWINKEL: Madam Chairman, before Mr. Franke takes the stand, would it be possible to take a brief break to discuss confidentiality with the company?

CHAIRMAN ARGENZIANO: Certainly. We'll take about a five-minute break.

MR. YOUNG: Madam Chairman, before we do that, I think Mr. Walls is going to ask for Mr. Doughty to be excused. He doesn't have rebuttal.

MR. WALLS: Yes. Mr. Doughty does not have rebuttal testimony, so we would ask he be excused from the hearing.

CHAIRMAN ARGENZIANO: He's excused. Let the poor guy go.

MR. WALLS: Thank you.

CHAIRMAN ARGENZIANO: Thank you. Let's take a five-minute break.

(Recess.)

CHAIRMAN ARGENZIANO: Where were we now? Did you get everything -- you got everything you needed, Mr. Rehwinkel?

MR. REHWINKEL: Yes, ma'am. The company has been very helpful in taking exhibits that I planned to use and reviewing them for confidentiality, not only for purposes of the Commissioners and parties in understanding what is confidential, but to eliminate or narrow down confidentiality within the documents. I appreciate it.

CHAIRMAN ARGENZIANO: Okay. Absolutely. Then we're square. Keino -- Mr. Young.

MR. YOUNG: Mr. Chairman, at this time I think Mr. Walls is going to make a request that Ms. Galloway's -- Dr. Galloway's Prefiled Testimony and

Exhibits be entered into the record.

CHAIRMAN ARGENZIANO: Be entered into the record?

MR. WALLS: That's correct. The parties have agreed to waive cross examination and stipulate to the testimony of Dr. Patricia Galloway's Prefiled Testimony on April 30th, 2010, into the record as though read and to the entry of her exhibits into the record. So we would move that her testimony be entered into the record.

CHAIRMAN ARGENZIANO: Hearing no objection, show that Dr. Galloway's testimony be entered into the record as though read.

MR. WALLS: And we have four exhibits, Exhibits PDG-1, 2, 3, 4, and 5, which are identified on staff's exhibit list as Numbers 14, 15, 16, 17, and 18, and we would move those into evidence at this time.

CHAIRMAN ARGENZIANO: Hearing no objection, those are moved into the record.

(Exhibits 14, 15, 16, 17, and 18 admitted into the record.)

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 100009-EI

DIRECT TESTIMONY OF PATRICIA D. GALLOWAY

I. INTRODUCTION AND QUALIFICATIONS.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Patricia D. Galloway. My business address is 1750 Emerick Road, Cle Elum, Washington 98922.

Q. WHAT IS YOUR OCCUPATION?

A. I am the CEO of Pegasus Global Holdings, Inc. ("Pegasus-Global"), a management consulting firm that provides services to the utility industry and other industries.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a doctorate in Infrastructure Systems (Civil) Engineering from Kochi University of Technology in Kochi, Japan in 2005, a Masters in Business Administration from the New York Institute of Technology in 1984, and a Bachelor of Civil Engineering degree from Purdue University in 1978. I have over 30 years of experience in the industry.

I have performed extensive work on behalf of both public and private sector clients, on a wide-range of complex, global engagements involving the construction, engineering, and procurement of large projects with long-lead times. I have an extensive background in engineering, construction, and project management, including controls and scheduling. I have been involved with pre-design, engineering, procurement, construction, and commissioning work for mega and large projects like the development of the Levy Nuclear Plant ("LNP"). This work includes significant experience in bidding and bid solicitation for such projects, procurement, constructability reviews, schedule resource loading and activity evaluation, code and permitting processes, due diligence studies, overhead calculations, quality assurance and control, startup and operations, commissioning, testing and maintenance. I have worked on engineering and construction projects in over 60 countries. My power plant experience includes over 65 power plants. My work experience is described in my curriculum vita, which I have attached as Exhibit No. ___ (PDG-1) to my testimony. My nuclear power plant experience is attached as Exhibit No. ___ (PDG-2) and my non-nuclear power plant experience is attached as Exhibit No. ___ (PDG-3).

As a senior Pegasus-Global leader or member on risk management or strategic consulting engagements, I have led management performance and prudence audits, evaluations and assessments of project-specific and corporate risk. These assignments have at times involved testimony in regulatory proceedings. They are identified in Exhibit No. ___ (PDG-4) to my testimony. Other management performance and prudence reviews have not required testimony in regulatory proceedings. These assignments are identified in Exhibit No. ___ (PDG-5) to my testimony.

I have authored over 100 papers and publications including papers in the area of prudence and utility management. I have also provided or participated in lectures on industry topics including management prudence. These papers, publications, and lectures are identified in Exhibit No. ___ (PDG-1) to my testimony.

I have presented expert witness testimony in legal proceedings around the world including numerous commission dockets regarding the prudence of multiple power plants. I have testified approximately 50 times and 16 involved power plant projects. As indicated above, my previous experience testifying in regulatory proceedings involving utility prudence issues is listed in Exhibit No. ___ (PDG-4) to my testimony.

I hold a Certificate in Director Education from the National Association for Corporate Directors and have also served on several corporate boards for both private, for-profit corporations and private, non-profit corporations. For example, I am currently a member of the boards for the American Arbitration Association and the National Science Board. My current and past service on corporate boards is included in Exhibit No. ___ (PDG-1).

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Progress Energy Florida ("PEF") asked me to perform an independent review to determine whether PEF made a reasonable and prudent decision to continue with the Levy Nuclear Plant project ("LNP").

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I have the following exhibits to my testimony:

- Exhibit No. ___ (PDG-1), which is my curriculum vitae;
- Exhibit No. ___ (PDG-2), which is my nuclear power plant experience;
- Exhibit No. ___ (PDG-3), which is my non-nuclear power plant experience;
- Exhibit No. ___ (PDG-4), which identifies my prior management prudence reviews involving my testimony in regulatory proceedings;
- Exhibit No. ___ (PDG-5), which identifies my prior management prudence reviews that did not involve testimony in a regulatory proceeding.

These exhibits are true and correct.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company decided to continue the LNP and focus primarily on obtaining the Combined Operating License ("COL") for the LNP from the Nuclear Regulatory Commission ("NRC"), and other necessary permits and licenses, deferring most other LNP work until the COL is obtained. In my opinion, PEF's management decision was reasonable and prudent based on the information known and that reasonably should have been known by management at the time the decision was made.

PEF made a rational, deliberate decision based on an established process for making management decisions within the Company. The Company used this process to collect the best available information, evaluate that information, identify viable alternatives or options including cancelling the project, and make a decision. This was no rash decision, rather, the Company prudently took steps to update information in light of evolving conditions and circumstances affecting the decision with respect to the LNP. The Company carefully considered the estimated costs and potential benefits, both in the short and long term, to the Company and its customers under each alternative or option. This deliberate process produced a reasonable and prudent management decision with respect to whether and how to proceed with the LNP in light of the conditions and circumstances facing the Company.

The Company reasonably and prudently implemented its management decision. The Company employed existing terms and conditions of the EPC Agreement that were included to address situations just like the schedule shift the Company faced on the LNP. These particular terms and conditions were reasonable and prudent under the circumstances and they were reasonably and prudently employed by the Company to preserve the contractual benefits under the EPC Agreement while implementing the Company's decision in an amendment to the agreement.

III. LNP PRUDENCE EVALUATION STANDARDS AND METHOD.

A. PRUDENCE STANDARDS.

Q. ARE THERE GENERALLY ACCEPTED PRUDENCE STANDARDS FOR MANAGEMENT DECISIONS?

A. Yes. The definition of a prudent management decision is best articulated as follows: *Decisions are prudent if made in a reasonable manner in light of conditions and circumstances which were known or reasonably should have been known when the decision was made.* This standard is set forth by the Florida Public Service

Commission ("Commission") in its Order No. PSC-09-0783-FOF-EI in the nuclear cost recovery docket last year. This definition is consistent with the prudence standard applied in other regulatory jurisdictions. This prudence definition is also consistent with the prudence standard used in numerous publications on the subject of prudent management decisions. This is the definition that I have used in the prudence reviews that I have conducted. In essence, management makes prudent decisions when management makes an informed decision under the circumstances at the time the decision is made.

Prudence, therefore, cannot be judged from a hindsight perspective. Only those circumstances that were known or that should have been known at the time the decision is made can be considered. Management decisions are not made in static conditions. Circumstances change over time and a management decision cannot be deemed imprudent based on unknown changes in the conditions or circumstances at the time the decision was made. Prudence, therefore, recognizes and relies on the concept of forseeability in two ways: First, an action or lack of action of a utility manager is not unreasonable or imprudent if it involves or is affected by events which were unforeseen and unforeseeable at the time; and second, the cost calculations for any imprudence found properly reflect only the foreseeable consequences of the imprudent decision-making processes or performance.

Prudence also involves the evaluation of facts at the time the decision was made. The issue is whether management considered factual circumstances and conditions that management should have considered in making its decision, not whether someone else would make a different decision under the same circumstances and conditions. Management decisions are seldom black and white, rather, more than one decision can prudently be made based on the same circumstances and conditions. The fact that someone else may make a different decision does not mean that management's decision was imprudent. Differences in opinion or judgment do not render a management decision imprudent. There is a zone of reasonableness in which management judgment is exercised and decisions are reasonable and prudent. Prudence is not a test of optimality. Although I found that PEF's decision generally fell within a zone of reasonableness and is therefore prudent, I have drawn no conclusion as to whether another reasonable course of conduct would have resulted in different consequences or costs. It is improper in a prudence review to substitute your judgment for that of management.

Prudence, however, is not merely the application of a test that accepts just any rational basis for acceptability of a decision. Rather, the prudence determination requires the evaluation of the concurrent context of the decision, the process for making the decision, and the performance or implementation of that decision by management. This does not mean that prudence is synonymous with efficiency. Prudence does not require that decisions be made and executed in the most efficient manner. It means that there must be some rational, deliberate process that accounted for the circumstances and conditions facing management that was employed by management to make and implement the decision.

Q. ARE THESE PRUDENCE STANDARDS CONSISTENT WITH PRIOR STANDARDS USED IN FLORIDA?

A. Yes. As I indicated above, the prudence definition that is the foundation for these standards was employed by the Commission in Order No. PSC-09-0783-FOF-EI in this docket last year. The prudence standards were also employed by the Commission in other proceedings. For example, in the 2007 Commission decision in the Compliance Investigation of IXC Registration [PUC LEXIS 561, at *124, *152], the Commission stated: "*Improper hindsight review involves applying facts as we know them today to evaluate decisions made in the past, thereby making a different course of action look preferable. In a proper prudence review, we consider the prudence of decisions made in the past by applying facts that were available to the company at the time of its management decision.*" Thus, the Commission has followed these prudence standards.

The prudence standards are also consistent with the nuclear cost recovery statute, Section 366.93, Florida Statutes, and nuclear cost recovery rule, Rule 25-6.0423, F.A.C., which provide for the recovery of all prudently incurred site selection costs, pre-construction costs and the construction carrying costs on construction cost balances on an annual basis. They are also consistent with Section 403.519(4) (e), Florida Statutes, which provides for the recovery of all prudent costs and provides that proceeding with the construction of a nuclear power plant following an order by the Commission approving the need for the nuclear power plant shall not constitute or be evidence of imprudence and that imprudence shall not include any cost increases due to events beyond the utility's control.

These prudence standards are consistent not only with Florida law but they are also consistent with the laws of most other jurisdictions. I reviewed those standards in a number of articles that I published and for presentations that I have made that are identified in Exhibit No. ___ (PDG-1) to my testimony. They are also consistent with the Government Auditing Standards issued by the U.S. General Accounting Office ("GAO") for prudence audits, especially with respect to capital projects, that I have often used as a guide in my prudence evaluations. (See Government Auditing Standards, United States General Accounting Office, GAO-03-673G, June 2007, Sections 1.25 –1.26, page 17, July 2007, the so-called "Yellow Book" standards).

B. PRUDENCE EVALUATION PROCESS.

Q. HOW DID YOU DETERMINE THAT PEF MADE A REASONABLE AND PRUDENT DECISION?

A. In conducting my evaluation, I focused on the management processes employed by the Company to make this decision and applied the generally accepted prudence standards to the Company's decision. This evaluation involved the determination that management followed a rational and deliberate process in making the decision with respect to the LNP. There must be a management structure in place to make such decisions and a process in place to ensure management makes an informed decision. Management makes an informed decision if, at the time the decision is made, management considers the factors management should have reasonably considered based on information that was known or shown have been known at the time the decision was made. An informed decision includes the identification of risks that might arise on the LNP and an appropriate consideration and evaluation of those risks in reaching that decision. Having determined that management made an informed decision I evaluated whether that decision fell within a range of reasonable business judgment. Most if not all management decisions do not involve right or wrong answers, rather, there typically are more than one decision that can be made that are equally reasonable and prudent under the circumstances facing management at the time the decision is made. As long as management's decision falls within this range of reasonable business judgment its decision is a reasonable and prudent one.

My evaluation also considered whether management reasonably and prudently implemented the decision it made with respect to the LNP. This evaluation involved (1) an assessment of the applicable terms and conditions of the Engineering, Procurement and Construction Agreement ("EPC Agreement"), executed by PEF and the "Consortium" of Westinghouse Electric Company, LLC and Shaw-Stone & Webster under the business conditions at the time the EPC Agreement was negotiated and in relation to other large capital projects with long-lead times, and current industry practices including risk allocation, and (2) an assessment of the amendment to the EPC Agreement to implement management's decision in March 2010 to continue with the LNP to determine if management reasonably and prudently implemented those terms and conditions.

Q. HOW DID YOU EVALUATE THE MANAGEMENT DECISION-MAKING PROCESS USED BY THE COMPANY?

A. My evaluation of the prudence of the decision-making process and the decision implementation included the following evaluation steps: (1) data development, (2) information flow, (3) analysis, and (4) decision. These steps are described below.

Data development addresses what information was available and determines if the management systems and procedures were organized and implemented in a way to produce available information in a reliable manner to management for analysis. It must be remembered, however, that the evaluation of the data development cannot be made with the advantage of 20-20 hindsight. Thus, we judge prudence from the position of utility management and based upon the varying sources of input that they had or reasonably could have had at the time of making a decision. Management never has the time to obtain or luxury of obtaining all information that they desire when making a decision. If management waited until management had all possible information it desired to make a decision, management would never make a decision. The very essence of management is making decisions on less than perfect information.

Information flow addresses to whom and when the available data was transmitted and communicated and in what format the information was made available to management. The evaluation of the information flow determines if management timely received the information in an understandable manner to make its decision.

The analysis step addresses how the information was evaluated, what alternatives, if any, were identified based on the available information, and what benefits and impacts are projected by management based on the information.

Finally, the decision step addresses what decision was made, when the decision was made, how the decision was made, how the decision met project, corporate, and customer needs, and whether the decision was reviewed as assumptions and circumstances changed. This requires management techniques and systems to monitor performance and use that information to continue to improve performance. Nowhere is this truer than in major capital construction projects and especially for capital construction programs, such as, PEF's LNP.

Q. HOW DID YOU APPROACH YOUR PRUDENCE REVIEW?

A. I used the same qualitative approach to the prudence review for the LNP that I have used for each prudence review that I have conducted. I requested, obtained, and reviewed project documentation sufficient to be reasonably sure that I could derive supportable conclusions from the documentation. This documentation consisted of reports, correspondence, meeting minutes, presentations and other written material and data related to project events, decisions, responses and actions. In addition, I identified and interviewed project personnel, including key PEF project team members and executives charged with direct oversight of the project. These interviews included Jeff Lyash, Executive Vice President; John Elnitsky, Vice President, Nuclear Plant Development ("NPD"); Sue Hardison, General Manager, Corporate Development and Group Business Services; Robert Kitchen, Manager, Nuclear Plant Licensing; Vann Stephenson, Manager, Nuclear Plant Engineering; and Ken Karp, General Manager, Levy Baseload Transmission Projects. The interviews were conducted to establish the basis or underlying explanation for decision making. In my opinion, these interviews are a necessary element of a comprehensive review to provide the rationale or justification for a management decision that cannot otherwise be determined solely from review of documentation. In reaching my conclusions in my prudence evaluation, I looked at the decision-making process and the decisions from the respective levels of management, taking into account each of the documents and interviews and applying the prudence standards.

Q. DOCTOR GALLOWAY, WHAT EXPERIENCE DO YOU DRAW UPON TO ADDRESS THE PRUDENCE OF MANAGEMENT DECISIONS ON LARGE CAPITAL PROJECTS LIKE THE NUCLEAR UNITS IN THIS CASE?

A. I have performed extensive work on behalf of both public and private sector clients, on a wide-range of complex, global engagements involving the construction, engineering, and procurement on large projects with long lead times. I have an extensive background in engineering, construction and project management, including controls and scheduling. I have been involved with pre-design work for mega projects like the LNP, including significant experience in bidding and bid solicitation for such projects, procurement, constructability reviews, schedule resource loading and activity evaluation, code and permitting processes, due diligence studies, overhead calculations, quality assurance and control, startup and operations, commissioning, testing and maintenance. I have worked on engineering and construction projects in over 60 countries.

I have also presented expert witness testimony on prudence type issues in legal proceedings around the world and I have been a member of prudence audit teams for large power plant projects, including nuclear power plants. I am currently assisting in prudence audits in Kansas and Missouri on the Iatan 1 and 2 coal generating units which have a combined project cost of $3 billion.

In addition, I have Board of Director experience and I have been involved in the Board decision-making process on those Boards which I serve as a director.

Finally, I am also a senior member on risk management engagements, and I have undertaken and led audits, evaluations, and assessments of project-specific and corporate risk. For instance, I am currently serving on an Independent Review Panel for the Governors of Washington and Oregon on the multi-billion dollar Columbia River Crossing project. This experience is described in more detail in my curriculum vitae attached as Exhibit No. __ (PDG-1) to my testimony.

Q. WHAT DO YOU MEAN BY THE TERM "MEGA PROJECT"?

A. "Mega projects" are defined as very large capital investment projects that attract a high level of public attention or political interest because of substantial direct and indirect impacts on the community, environment, and companies that undertake such projects. They are generally defined as major projects that cost more than $1 billion (US). I have worked across the world on mega projects costing several billion dollars (US). A recent example is the $20 billion CrossRail project in London where I am working for Her Majesty's Treasury regarding risk management. PEF's construction of the LNP is a mega project under this definition.

IV. THE COMPANY'S MANAGEMENT DECISION WITH RESPECT TO THE LEVY NUCLEAR POWER PLANT PROJECT WAS REASONABLE AND PRUDENT UNDER THE CIRCUMSTANCES.

Q. WHAT DECISION DID PEF MANAGEMENT MAKE WITH RESPECT TO THE LNP?

A. The Company decided to continue the LNP and focus primarily on obtaining the COL for the LNP from the NRC, and other necessary permits and licenses, deferring most other LNP work until the COL is obtained. This decision was made in response to the schedule shift the Company faced as a result of licensing delays beyond the Company's control and additional circumstances affecting the project risks. As a result, the Company addressed the options available to the Company. These options included (1) terminating the EPC Agreement and cancelling the project, (2) proceeding fully with the project on the shortest possible schedule, and (3) amending the EPC Agreement to suspend most work and capital investment in the project until the COL is obtained and focusing near term efforts on obtaining the COL. The Company engaged in a deliberate evaluation of each option to determine the option that was in the best interests of the Company and its customers considering the costs, short- and long-term benefits, and risks associated with each option. The Company concluded that amending the EPC Agreement to focus near-term LNP work on obtaining the COL with most work deferred until the COL was obtained was the option that was in the best interests of the Company and its customers.

Q. WAS THAT A REASONABLE AND PRUDENT MANAGEMENT DECISION?

A. Yes. PEF's decision to partially suspend the LNP until receipt of the COL for the project from the NRC was both reasonable and prudent based on the information known and that reasonably should have been known at the time the decision was made. This was a rational, deliberate decision based on an established, known process for making management decisions within the Company. The Company employed its existing management framework and decision-making processes to collect relevant information, evaluate that information, and make a decision. The Company did not make a rash decision before all facts and circumstances that might affect the decision were considered. The Company did not side step its decision-making framework and processes to make this decision. The rational, deliberate process the Company employed to make its decision with respect to the questions whether and how to proceed with the LNP produced a reasonable and prudent management decision. Further, the Company reasonably and prudently implemented that management decision under the existing terms and conditions of the EPC Agreement that were included to address situations like the schedule shift the Company faced on the LNP. These particular terms and conditions were reasonable and prudent under the circumstances and they were reasonably and prudently employed by the Company to preserve the contractual benefits the Company had in place under the EPC Agreement in an amendment to the agreement.

Q. DID YOU CONSIDER THE CIRCUMSTANCES IN WHICH THIS DECISION WAS MADE?

A. Yes. Consideration must be given to the particular point in the execution period. For example, PEF was delayed from their 2008 plans by the NRC decision to review the Limited Work Authorization ("LWA") application over the same time period as the Combined Operating License Application ("COLA"). Once the various schedule shift scenarios were received from the Consortium in August 2009, PEF found it was faced with a considerably different construction market. I point this out because circumstances and conditions seldom remain static over the extended durations of major capital construction. When judging the prudency of decision making, we place decision making in the factual context of what could reasonably be known at the time. Once the decision is made, there also must be recognition of the time to implement or respond to the decision, during which circumstances and conditions are not static. From the end of 2008 to today the shifting issues and resulting circumstances have gone through many changes. For that reason we place the decision making process into time context or continuum that existed at the time the decision was made.

Q. DID THE COMPANY HAVE A MANAGEMENT STRUCTURE IN PLACE FOR A RATIONAL AND DELIBERATE PROCESS WITH RESPECT TO THE DECISION TO PROCEED WITH LNP?

A. Yes. Progress Energy and Progress Energy Florida assure a deliberate and rational decision-making process through a management committee structure flowing from the detailed project level up to the Board of Directors. The process is outlined in the Levy Governance Policy MGT-NPDF-00001 developed for the LNP in June 2009 and updated in December 2009. Briefly, the oversight and discussion of project issues, including impact to LNP cost and schedule, are first performed by the Program Management Team ("PMT") whose role and responsibility is to serve as a means to review and manage ongoing program and project activity for development of the LNP and associated transmission. The PMT is chaired by John Elnitsky, Vice President of NPD. Its membership includes direct department leadership and key stakeholders who provide functional support to the program including licensing, engineering, project management, project controls, legal and external relations. The PMT is structured within the project management culture of NPD and aligns with other program management and project reviews established to support project activities, status and oversight. PMT meetings occur weekly as needed.

John Elnitsky also sits on the then Levy Integrated Nuclear Committee ("LINC") and now the Project Performance Review ("PPR") committee whose purpose is to provide periodic program performance and project status to the Executive Sponsor and the Senior Management Committee ("SMC"). The PPR reviews and discusses the issues as presented by the PMT relative to LNP and makes recommendations for management action and decisions to the SMC. The SMC consists of Senior and Executive Vice Presidents of Progress Energy. As with all major projects, the SMC is engaged in oversight, funding authorizations and ongoing performance reviews of the LNP. The SMC is informed of project status monthly using standard company reporting templates, thus ensuring consistency of information to be reviewed and used in the decision making process. The SMC is briefed prior to Board Meetings relative to LNP to allow for discussion of status and proposed actions to in turn provide the Board of Directors with data and information to allow the Board to make informed decisions.

Jeff Lyash is both a member of the PPR and the SMC. Jeff Lyash is then responsible for identifying those issues, actions and recommendations relative to the LNP for discussion and decisions to the Board Committee for Operations and Nuclear Oversight and the Board of Directors for PEF and Progress Energy, Inc.

The Board of Directors is the highest governing authority within the management structures and is charged with the overall responsibility for the Company. The role of the Board is to establish policy which the Company will follow, to oversee how management serves the long term interests of the shareholders and other stakeholders within the framework established by applicable legal and regulatory systems and to make major business decisions such as (1) establishing and amending bylaws, (2) issuing dividends, (3) approving major contracts or mergers, (4) making key decisions regarding assets owned or managed by the Company and (5) electing or appointing officers. The Board does not handle day to day activities of the Company and leaves that to the officers of the Company. Board members are required to act in a prudent manner on behalf of the Company's best interests. All Board activities are documented to show that the Company's business was conducted reasonably. Jeff Lyash attends each Board meeting with Bill Johnson, the Chief Executive Officer and a member of the SMC, and is responsible to the Board of Directors for the LNP information presented to and considered by the Board of Directors. Jeff Lyash and Bill Johnson make presentations to the Board Committee and the full Board of Directors regarding LNP status and information for Board consideration in its decision-making process.

The Board Committee for Operations and Nuclear Oversight is comprised of experienced individuals in the nuclear area. These individuals include Charles W. Pryor, Jr., Chairman of Urenco Investments, Inc, a global provider of value added services and technology to the nuclear generation industry. Mr. Pryor was previously with Westinghouse. They also include Alfred C. Tollison, Jr., retired Chairman and Chief Executive Officer of the Institute of Nuclear Power Operations, an industry sponsored nonprofit organization. This Committee has the experience and expertise to raise questions and deliberate on the issues presented to them with respect to nuclear generation projects like the LNP. Although the Board Operations and Nuclear Oversight Committee is not a recommending committee to the Board of Directors, Committee members are members of the full Board and attend the full Board meetings where they provide insight and information relative to specific issues involving LNP.

This management organization provided the necessary structure for a rational, deliberate process to make a decision with respect to the LNP. It was well defined and known within the organization at the outset of the project. Roles were well defined and known to ensure that available information was provided to support the recommendations for management decisions at each level of the organization. The overlap of senior management personnel throughout the management committee organization of the parent and subsidiary company also provided the structure to ensure that the decision makers at each step in the process were fully informed to make a decision. This was an appropriate management structure for a reasonable and prudent decision making process.

Q. DID THIS MANAGEMENT STRUCTURE DEVELOP AVAILABLE INFORMATION AND ENSURE THAT IT WAS PROVIDED TO MANAGEMENT TO MAKE AN INFORMED DECISION?

A. Yes. The documentation I reviewed, which was provided by and to the various committees I have just described, was complete and conveyed information that was known and should have been known at the time decisions were made both internally and externally with regards to the nuclear industry and the LNP in particular.

When PEF learned that an LWA would not be issued on the schedule that was contemplated under the EPC Agreement with the Consortium, PEF requested the Consortium to evaluate various scenarios of shifting the schedule and the impact these various schedule shift scenarios would have on the overall cost of the LNP going forward. The results of the scenario analyses were one factor that was necessary to PEF's decision concerning the schedule shift for the LNP Commercial Operation Date and a foundation for negotiating an amendment to the EPC Agreement. The LNP is a complex project with an intricate EPC Agreement between PEF and the Consortium that involves multiple sub vendor and equipment supplier arrangements between the Consortium and its suppliers. Any amendment to the EPC contract thus required input from these subcontractors to the Consortium regarding how various schedule shift considerations might affect PEF's place in the manufacturing process and/or potential cancellation costs. PEF simply could not just pick a date without consideration of the impacts from multiple scenarios unless it had the input from the Consortium (and the Consortium's subcontractor vendors) on these scenarios. In conducting the scenario analysis, PEF outlined key criteria to be evaluated including cost certainty, schedule certainty, cash flow requirements and restrictions, availability for manufacturing/capacity/storage, engineering and craft labor continuity and availability, among others. The Company considered the Consortium input in addition to other considerations addressing circumstances that affect both the Company and the customer, reducing near-term capital commitments, and preserving long-lead items. These considerations were part of the decision making process which also considered the potential for unanticipated COL delay and the suspension provisions under the EPC Agreement.

This was a rational, deliberate and thorough approach to making a reasonable and prudent decision with respect to addressing the LNP schedule shift. Once the NRC LWA determination was confirmed, PEF put the Consortium on notice of the likely schedule shift and to begin reducing expenditures for the remainder of 2009. PEF turned to the terms and conditions of the EPC Agreement relative to its options to suspend the work, its payment obligations, protection of the work, and resumption of the work. During the period from notice of partial suspension until the March 2010 decision to amend the EPC Agreement, data and information continued to be gathered, evaluated and flowed up and down the organization through the PMT, PPR, SMC and Board with options modified and refined as information became known and as conditions and circumstances changed during this time. The Company continued to monitor and evaluate its options considering customer price impacts under adverse economic conditions, the capital market deterioration, financial risk mitigation during the on-going recession, and the uncertain political and regulatory climate. The Company continued to review and preserve all options in the manner I have described while at the same time instituting the governing policies and procedures for LNP, transitioning from the LINC to the PPR, holding discussions with the Consortium regarding suppliers for major equipment and components regarding the schedule shift and reviewing external industry nuclear developments. Based on input from the Board and the SMC, the PPR continued to evaluate the information and negotiate an amendment to the EPC Agreement with the Consortium resulting in draft principles under which the amendment would be prepared.

This process resulted in a reasonable and deliberate process for developing the information necessary for management to make an informed decision relative to the schedule shift under the terms and conditions of the EPC contract with the Consortium and the evolving conditions and circumstances facing the Company with respect to this decision.

Q. DID MANAGEMENT CONSIDER THE FACTORS THAT THEY SHOULD HAVE REASONABLY CONSIDERED BASED ON INFORMATION THAT WAS KNOWN OR SHOULD HAVE BEEN KNOWN AT THE TIME OF THE DECISION?

A. Yes. PEF first considered factors that affected the project schedule and pricing, such as, material, long-lead equipment, and labor. This was based on information that was developed by the project teams and PMT after analysis of the schedule shift scenario results provided by the Consortium. The results of this analysis were included in the recommendations to SMC along with information developed from other sources, including the on-going impacts of federal and state regulatory licensing activities and the review of enterprise risks by the Company. Enterprise risks were risks that were beyond the control of the Company that had an impact on the Company and the LNP, such as the economy, capital market conditions, and state and federal regulatory and legislative policies. All of this information was appropriately developed by the project team and included with the recommendations to SMC and the Boards.

PEF further considered the benefits obtained upon EPC execution in the EPC Agreement and the long term benefits of nuclear generation to the Company and its customers during this decision-making process. The EPC Agreement benefits included: [redacted] PEF considered all these factors in its decision-making process regarding the terms and conditions of the EPC contract, including how to best structure the terms and conditions in any amendment to the EPC Agreement in order to maintain the most flexibility for the LNP.

In addition, as part of its decision-making process, the Company assured that it had information and was informed of current and best industry practice in the nuclear industry through senior executive management, such as Jeff Lyash and John Elnitsky, in nuclear industry associations including the Nuclear Plant Oversight Committee, the INPO New Plant Executive Group and the AP1000 Builders Group, to name a few; and through its Board members as I have previously discussed.

The deliberations leading up to management's March 2010 decision indicate that this information was included in management's deliberations as management considered (i) maintaining the LNP as a viable option for the long-term benefits of nuclear generation in Florida; (ii) managing the financial impact to customers and providing near-term customer price relief; (iii) shifting capital expenditures beyond the COL and reducing near-term Company capital expenditures; (iv) providing transmission flexibility; (v) allowing time for more certainty in federal and state electric industry policy; and (vi) allowing time for the settling of and improvement in the economy and financial markets.

The information developed at the project team level and flowed to management with respect to the decision PEF faced regarding how to address the shift in the schedule demonstrates that management had available information to make a decision, that this information was appropriately updated as management deliberated on what decision to make, and that management's decision included information on factors known to management at the time and that should have been known or considered at the time the decision was made.

Q. DID MANAGEMENT IDENTIFY RISKS THAT MIGHT ARISE ON THE LNP AND APPROPRIATELY CONSIDER THOSE RISKS IN ITS DECISION?

A. Yes. Risks were identified by management as part of PEF's risk management practices and policies, including risk mitigation strategies developed for the risks identified. Risks must be identified and appropriate protections established to prevent or control them. Prudent decision-making results from orderly, well-defined processes that address known risks, needs and capabilities. Adherence to written procedures, effective communication, internal and contractor oversight, and ongoing auditing and quality assurance are essential to ensure that project costs are incurred prudently.

My review of the PEF policies and procedures indicates that PEF did have in place policies and procedures that addressed how risk would be identified, monitored, and handled. PEF follows a formal Corporate Project Risk Management program adopted in March 2009 (PJM-SUBS-0008), which provides structured guidance on project risk management. PEF identified both project risk and contextual risk in its decision-making process. In addition to project risks, other enterprise risks were considered that could potentially impact the LNP, as I noted above, including impacts of the economy on the capital markets, financing, regulatory and legislative uncertainty, and other factors that have the potential to materially alter the LNP schedule and cost. PEF continued to evaluate the risks identified and which arose from the decision to shift the schedule at the time of the LWA decision and through its March 2010 decision to defer certain work until COL receipt.

The risks identified by PEF are risks inherent in a long-term base load project like LNP. While these risks cannot be eliminated, PEF has a structure which allows the identified risks to be monitored and managed with appropriate responsive risk mitigation strategies. It would be unreasonable to expect a utility to eliminate these risks or obtain certainty with respect to these risks for a nuclear power plant project.

Q. WAS MANAGEMENT'S DECISION WITHIN A RANGE OF REASONABLE BUSINESS JUDGMENT?

A. Yes, it was. In applying the prudence standards we must remember that decision making is not an absolute science. It involves using human judgment to identify and select a course of action based on a set of identified conditions. It is entirely possible for two individuals faced with the same set of conditions to make different, reasonable decisions; that is where human judgment comes into play. Therefore, the question of prudence is not whether the decision is viewed as a right or wrong decision today, but whether the decision was an informed one based on a rational, deliberate process. That means relevant information was collected, interpreted, and analyzed by management in reaching management's decision, and the decision ultimately selected reflects the analysis of that information under contextual conditions of the project at the time of the decision. If that is the case, the management decision is within the range of reasonable business judgment even if another experienced individual or company might reach the same or a different decision based on the same information and contextual conditions at that time.

Against this backdrop, my examination of the PEF decision making processes, the information and data that was actually collected, interpreted and analyzed prior to development of alternative responses, and the ultimate decisions made by PEF, reveal that PEF followed a rationale and deliberate process prior to identifying alternative responses to the events and issues which arose and existed in 2009 and 2010 concerning the LNP. My examination further determined that PEF identified and evaluated the risks which existed as a result of the current project conditions and the changes to the project risk profile which would accompany the various alternative actions under consideration. Based on my examinations, I concluded that the decision made by PEF was reasonable and prudent.

Q. PLEASE EXPLAIN THE REASONS FOR YOUR CONCLUSION.

A. To begin with, events and issues which arose after the decision to proceed with the LNP and the execution of the EPC Agreement in 2009 had a significant impact on the planned project schedule, which in turn resulted in a shift in the project's risk profile. In summary, the decision by the NRC to withhold action on the LWA prior to issuance of the COL meant that PEF would gain no construction progress against the project schedule prior to receipt of the COL from the NRC. Further, the regulatory situation relative to the certification of the AP1000 and the general uncertainty with respect to the licensing schedules being set by the NRC appeared to have the potential to further delay licensing actions by the NRC within the schedules set by the NRC and PEF. This meant that the expenditure of funds prior to the receipt of the COL would have no direct benefit or limited benefit to either PEF or its customers.

Given the change in the project risk profile, PEF was faced with three options: (1) continue the project at "full speed" as originally planned; (2) cancel the project entirely; or (3) continue the project under partial suspension, adjusting the project execution plan to reduce the near term capital investment cost impact on PEF and its customers. One of the primary considerations in all three options involved the EPC Agreement. Other considerations were the information developed by the project management team and provided to management regarding the NRC licensing schedule issues, project cost impacts of each option, and potential project and enterprise risk impacts.

Under Option 1, full speed continuation under the most aggressive, revised project schedule, the expenditure rate under the EPC Agreement would continue at a rate which simply was not acceptable to PEF, even though that work would have ultimately been required to execute the project. PEF reached this conclusion based on an evaluation of the information before management, including the near-term customer bill impacts during an on-going recession, capital market conditions, and the exposure of significant capital invested in the project prior to obtaining the COL given the project and enterprise risks.

Under Option 2, the first impact under the EPC Agreement would be a [redacted] In addition, all of the benefits and advantages gained in executing the EPC Agreement early would be lost should PEF later decide to reinstate the project and, as a result, have to renegotiate the EPC Agreement. The Company further considered the likely loss of the long-term benefits of nuclear generation in the event of project cancellation given the likely focus of industry and regulatory resources on active nuclear development projects.

Under Option 3, assuming that the EPC Agreement terms and conditions could be amended to preserve the primary benefits and advantages while at the same time extending the project schedule and reducing near term expenditures, PEF could maintain the maximum number of options in response to issues and events which might occur prior to the NRC issuance of the COL. Ultimately the decision rested on whether or not PEF could amend the EPC Agreement to (1) preserve the maximum benefits already negotiated into that contract, and (2) enable PEF to significantly reduce the near term expenditures on the project.

Q. HOW WERE THESE OPTIONS EVALUATED AND CONSIDERED BY PEF?

A. Each of those options was developed and presented to PEF Senior Management in a series of meetings held between October 15, 2009 and March 8, 2010. In a SMC meeting held on February 15, 2010, full discussions relative to the pros and cons of each of the three viable options were discussed. It was noted during that meeting that NRC issuance of the COL would occur, at the earliest, in the 4th quarter of 2012. Based on that date, PEF identified the ability to meet an in-service date of 2019 as "optimistic" at best. PEF further noted that given the schedule impacts, Option 1 had the highest near term expenditure impact on PEF customers and the highest cash flow impact on PEF, while providing the least protection against future risk impacts which may manifest while awaiting NRC COL approval. In short, doing nothing did not appear to be a reasonable option or provide substantial benefit to the Company and its customers.

During that February 2010 meeting it was reaffirmed that nuclear generation remained a vital and viable baseload generation choice which should remain part of PEF's long term planning. Given that affirmation, while Option 2, cancellation of the project, might address the near term cost impact of simply continuing the project at full speed, that option had the potential to seriously impact PEF's ability to bring nuclear power generation on line in the foreseeable future. However, if the EPC Agreement could not be amended in such a way to preserve the maximum benefit while significantly reducing near term costs, Option 2 was preferred over Option 1.

Option 3 was the preferred and recommended option put forward by PEF Management. This option, in management's judgment, was in the best interests of the Company and its customers considering the risks and impacts associated with the near term investment of significant capital in the project weighed against the benefits of the LNP to the Company and its customers. However, that option was

REDACTED

based upon PEF successfully negotiating an amendment of the EPC Agreement which extended the project schedule, reduced near term cost, and preserved the maximum benefits contained in the EPC Agreement.

The Company reasonably pursued the potential for such an amendment with the Consortium before making a final decision. The basic principles for such an amendment were discussed with the Consortium during several meetings in late 2009 and memorialized in a letter dated January 8, 2010, within which PEF laid out the conditions under which it would be willing to amend the current EPC Agreement. Chief among those principles was that [redacted]

At a meeting held on March 8, 2010, SMC was briefed on the status of negotiations with the Consortium, noting that [redacted] The advantages of the negotiated amendment were minimization of near-term costs and customer impact, reduction in the cost uncertainty at the resumption of the full project, maintenance of the benefits gained in the original EPC, including the [redacted]

SMC approved Option 3 on this basis and this recommendation was presented to the Board.

Q. WHAT WAS THE PROCESS USED BY THE BOARD IN ITS DECISION MAKING PROCESS REGARDING THESE OPTIONS?

A. The Board approved SMC's recommendation at a March 2010 Board meeting. The Board's decision to partially suspend the LNP until receipt of the COL was based on consideration of the information before the SMC that was presented to it regarding the options before the Company, the pros and cons of each option, and the recommended option and basis for the recommendation. The Board considered all these factors in conjunction with the terms and conditions of the EPC Agreement and the fundamental reasons for selecting the LNP as a part of Progress Energy's Balanced Solution long term energy strategy. These reasons were recognized by the Commission in the approval of the need for the LNP and included fuel portfolio diversity, reduction of PEF's reliance on fossil fuels for energy production, carbon free energy generation, and the provision of unparalleled base load capacity with a relatively lost cost fuel source for PEF and its customers.

Q. WAS THIS A REASONABLE AND PRUDENT PROCESS?

A. Yes. As this summary shows, PEF obtained, evaluated, and analyzed relevant information regarding the decision it had to make with respect to the schedule shift, including timing and cost information from the Consortium and its vendors, and information regarding the risks that arose during 2009, including certain enterprise risks such as the national economy, reduced load growth in Florida, continued uncertainty with respect to federal climate change policy, PEF credit ratings, DCD delays, and ASLB contentions. This process of gathering, evaluating, and analyzing the information took considerable time given the nature and complexity of this project. This is not, however, unusual for megaprojects like the LNP. The decision whether and how to proceed with the LNP is a complex one and prudence requires that the necessary time be invested in gathering and analyzing the relevant information to make such an important decision with respect to the LNP.

Further, during the course of obtaining, evaluating, and analyzing the relevant information, and based on the risks identified, the Company identified potential, alternative decisions that included cancelling the project. Management, therefore, was not predisposed to continuing the project or to any particular LNP option. Rather, management reasonably weighed the pros and cons of each option before deciding on an option, and even then, management considered whether there were any necessary conditions to proceeding with that option. Having identified such conditions, management reasonably did not proceed with this option until the Company was assured those conditions were met. This was an informed decision based on a rational, deliberate decision-making process by Company management and, therefore, in my opinion, the decision is a reasonable and prudent decision within the range of reasonable business judgment.

Q. DID MANAGEMENT REASONABLY AND PRUDENTLY IMPLEMENT ITS DECISION IN MARCH 2010 TO CONTINUE WITH THE LNP?

A. Yes. PEF management specifically took advantage of the suspension and termination clauses that were reasonably and prudently obtained when the EPC Agreement was originally executed to negotiate a favorable amendment to that EPC Agreement identified as Amendment 3 to the agreement.

Leading up to the March 2010 Board meeting and its decision to execute Amendment 3 to the EPC Agreement, PEF senior management spent months negotiating the proposed amendment to the EPC Agreement. As noted above, PEF management and the Board of Directors considered both termination and suspension of the contract including the benefits and risks associated with each decision. During the negotiations of Amendment 3, PEF was able to [redacted] of the EPC Agreement. [redacted] Amendment 3 to the EPC Agreement achieved all of these Company objectives.

Q. HOW DID AMENDMENT 3 ACHIEVE THE COMPANY'S OBJECTIVES?

A. Amendment 3 allows for the amendment of certain provisions of the EPC Agreement while the remaining provisions remain intact. There are significant elements of Amendment 3 that provide minimal cost to PEF and its customers while at the same time preserving the nuclear option and the terms and conditions of the EPC Agreement. These are:

[redacted]

REDACTED

However, this provision provides the Company sufficient time to evaluate the project and decide how to proceed after the COL is issued [redacted]

[redacted] Amendment 3 successfully mitigates project and enterprise risk prior to receipt of the LNP COL by shifting substantial capital investment in the project until after the COL is obtained. [redacted]

REDACTED

[redacted]

The terms and conditions of the EPC Agreement provide the framework under which PEF was able to execute its decision and has resulted in benefits to the Company, its shareholders, the customers, and the State of Florida. The benefits of this decision include: (1) slowing down spending on LNP until after the COL is issued; (2) preserving the long term value of the project and COLA while reducing near-term price impacts to customers; (3) providing time for lessons learned to be obtained from the completion of other AP1000 nuclear plants including China's Sanmen Unit 1 and Georgia Power's Vogtle Unit 3; (4) providing the ability to monitor any changes and uncertainties in the licensing schedule; (5) allowing additional time for the current economic recession to subside; (6) providing greater certainty surrounding carbon regulation and its costs; (7) providing more time to see how demand-side management goals affects customer price; and (8) allowing PEF the benefit of alternative technologies that may be available at the time.

As a result, I have evaluated the decision-making process and the decision to implement the partial suspension of the LNP and conclude that both the process and decision are what I would have expected to see and are reasonable and prudent under the prudence standard I have employed.

Q. WHAT WERE THE FAVORABLE TERMS AND CONDITIONS OF THE EPC AGREEMENT THAT YOU CLAIM WERE PRESERVED UNDER AMENDMENT 3 TO THE EPC AGREEMENT?

A. There are several EPC Agreement provisions that are favorable to PEF. These include [redacted].

They also include the following:

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

The terms and conditions of the EPC Agreement align the penalties and incentives and the appropriate amount of fee at risk so that all parties are driven by the same goals of cost and schedule control. PEF maintains control through various clauses including favorable termination and suspension clauses which have proven to preserve the benefit of the EPC Agreement while at the same time being able to suspend the work as the direct result of unforeseeable delay or circumstances.

REDACTED

The suspension clause in fact worked just as it was intended by providing PEF with a contractual mechanism to handle the schedule shift on the LNP when it occurred. PEF had the right to suspend all or part of the work [redacted]

In my opinion, the EPC Agreement terms and conditions that PEF preserved with Amendment 3 to the EPC Agreement are beneficial to PEF and its customers. PEF senior management and the Board worked hard to get the favorable terms and conditions of the EPC Agreement and took reasonable and prudent steps to preserve these favorable terms and conditions.

To illustrate this further, let's look at [redacted] under the EPC Agreement. These provisions require the [redacted] A major component of the risk of constructing a nuclear power plant in the U.S in the past has been the acceptance and issuance of an Operating License for the final plant. This risk is partially mitigated with the application of the COL, which combines approval of the construction license with that of the operating license. However, it is still an NRC requirement that the licensee demonstrate through ITAAC that the plant has been designed and constructed in compliance with the certified design. Westinghouse has developed the standard plant based on the AP 1000 which has been certified by the NRC. Through this involvement with the Design Certification by the NRC, the Consortium is in the best position to influence the NRC's development of the ITAAC requirements. Under the EPC Agreement, [redacted]

This area is one where the [redacted] When supplemented by using a standard design and criteria that will be defined in advance by the NRC when they issue the ITAACs, there is enhanced project definition. The lack of complete definition has historically been a prime source of claims between the Owner and EPC Consortiums. Based on my experience in the industry and best industry practices, as this one example illustrates, I believe that the terms and conditions are reasonable and prudent in relation to other large capital projects with long-lead times and they are consistent with current best practices in the industry with respect to project risk allocation, including the risk of unforeseen schedule shifts that PEF experienced on the LNP.

Q. IS IT BENEFICIAL FOR PEF TO HAVE THE LNP EPC AGREEMENT GIVEN THE ENVIRONMENT FOR NEW NUCLEAR GENERATION?

A. Yes. The EPC Agreement provides the flexibility in contracting approaches that is needed to address cost, timing and schedule uncertainties, and appropriately allocate risk with respect to megaprojects, especially nuclear generation megaprojects. Based on industry practice, and the nature of the issues that will be experienced during construction of the LNP, some form of an EPC-type contract with a firm/fixed price structure is the most preferable contracting methodology. Clearly, LNP is a "megaproject", with respect to its overall cost, equipment lead times, and construction schedule. The execution of the LNP is scheduled to extend over a number of years. The keys to obtaining a firm price on such a megaproject are a well defined scope, quality level, and execution schedule. The EPC Agreement includes all these key objectives.

The Firm/Fixed price model takes into account the risk of the projected pricing over an extended time, in other words, "escalation". In the case of a period longer than 3 or 4 years, the amount of escalation that a Consortium feels compelled to add to its pricing would include a large contingency because of the variability in the local and global markets of pricing. The amount of contingency has to be reasonably predictable and as a result the amount of contingency would be unacceptable to most owners. As a result, parties attempt to establish some means or mechanisms to keep the benefits of what can be quantified and priced in a reasonable range. [redacted]

In recent years, most mega projects have been large projects such as dams, tunnels, bridges, railroads, airports, or oil and gas upstream projects. In the latter case, there is an urgency that makes such projects schedule driven as well. In both cases, the need and desire on the part of the Owners for more fixed pricing makes these projects comparable with the LNP. With respect to these mega projects, I have seen comparable fixed and firm pricing and risk allocation for meeting project parameters for the engineer, equipment vendors, and the consortiums on these projects to the EPC Agreement between PEF and the Consortium. These are therefore typical best industry practice for allocating the responsibility to meet the Owner defined expectations (and regulators' expectations in the case of a nuclear power plant) exactly because they place the risk on the parties who are in the best position to control the risks when the project has adequate definition. With the [redacted] cost risk is shared appropriately for the escalation that neither party can control. This process has been followed by PEF in selecting an EPC Agreement for the LNP execution methodology and taking the necessary steps to obtain a Firm/Fixed pricing [redacted] the total contract price and builds upon the lessons learned from the past decade. The selection by PEF of a [redacted] firm/fixed price EPC Agreement was prudent and meets best industry practice.

Q. DID MANAGEMENT REASONABLY ASSURE ITSELF THAT THE BENEFICIAL TERMS AND CONDITIONS OF THE EPC AGREEMENT THAT ARE PRESERVED BY THE AMENDMENT ARE IN FACT BENEFICIAL TO THE COMPANY?

A. Yes. PEF considered a number of factors to assure itself that the terms and conditions of the EPC Agreement were reasonable and prudent. As redacted copies of other AP1000 EPCs became available in the public domain through other regulatory proceedings, PEF reviewed these agreements to glean information that was useful in ongoing negotiations with the Consortium. PEF also contracted with other experienced companies to gauge typical commercial terms available in the competitive nuclear market for EPC type contract delivery approaches. PEF further established a core negotiating team and that core team remained in place throughout the negotiation process and EPC contract signing. This PEF core team spent over a year negotiating the EPC Agreement. When necessary, the PEF core team relied upon the outside expertise from Burns & Roe ("B&R") to evaluate and provide observations regarding the quality of the original cost book for the LNP and preliminary schedule and PriceWaterhouseCoopers (PWC) to independently review and provide observations to PEF regarding the EPC structure and the terms and conditions. Both B&R and PWC provided international knowledge with respect to engineering and construction and terms and conditions with respect to mega projects. PEF considered all observations provided from both B&R and PWC as part of the information it relied upon for its negotiations with the Consortium.

The knowledge gained positioned PEF to better understand the market and to use this insight to better leverage its position with the Consortium. In order to preserve the ability to move the LNP forward, yet still continue negotiations with the Consortium relative to the terms and conditions of the EPC Agreement, PEF entered into a Letter of Intent ("LOI") in March 2008 with the Consortium which allowed certain long lead equipment to proceed with its procurement. The indicative price for the EPC Agreement was based on a number of factors, including market conditions, risk allocation, and contingency. The final accepted price was a negotiated price which had been adjusted from that initially offered by the Consortium based on these factors as well as [redacted]. In addition, to reduce the impact of price uncertainties and other risks to PEF, PEF obtained language in the contract to require the Consortium to provide certain [redacted] Relative to schedule uncertainties, the EPC Agreement contained provisions to address changes in the schedule.

It is my opinion that PEF conducted its negotiations with the Consortium in finalizing the EPC Agreement based on internal and external information known to it at the time and based on information that was available to PEF at the time, including seeking advice from external experts in order to obtain reasonable and prudent terms and conditions that would best serve the Company, its shareholders, customers, and the State of Florida.

Senior management was closely involved in the negotiation of the EPC Agreement. Jeff Lyash, who was a member of the core team that was involved in the negotiations, was President and CEO of PEF at the time and was involved in PEF's decision to sign the EPC Agreement. Mr. Lyash approved the signing of the EPC Agreement. He was also a member of the SMC and provided the necessary overlap to inform the SMC regarding the terms and conditions of the EPC Agreement and the benefits it preserved for its customers. As a member of the SMC, Mr. Lyash was also involved in the presentations to the Board of Directors relative to its decision to approve execution of the EPC Agreement in December 2008.

At a meeting of the full Board of Directors held on December 10, 2008, Senior PEF Management reviewed the then current status of the LNP and reviewed with the Board the conditions under which PEF should consider proceeding with the execution of that project. The primary focus of that presentation was on the EPC Agreement, credible financing plans, possible appropriate joint ownership, and regulatory and political support for the project. The financial implications for the LNP were reviewed with the full Board of Directors. Management provided a summary presentation on the anticipated project schedule for both units with construction (non-safety) starting in 2010 and completion in 2017 (Unit 2). PEF Management anticipated NRC COLA approval for the start of safety construction by 2012.

Ultimately PEF Management recommended to the Board of Directors that the LNP go forward, including the execution of the EPC Agreement, provided that the [redacted] of the EPC Agreement. As part of the discussion, Management proposed the formation of an ad hoc Nuclear Project Oversight Committee to provide governance during the execution of the Project. The Board approved by formal resolution proceeding with the LNP, including the execution of the EPC Agreement, citing the requirement that the EPC Agreement contained the [redacted] recommended by PEF Management.

PEF considered all of the contractual provisions as a whole in determining whether the EPC Agreement represented a reasonable overall deal given the market conditions at the time. In summary, it is my opinion that Company management did take reasonable steps to ensure that the terms and conditions that were agreed in the executed EPC Agreement in December 2008 were beneficial to the Company, its shareholders, customers, and the State of Florida. These beneficial terms and conditions include the provisions for an orderly framework to accommodate potential adjustments to the schedule such as the schedule shift that resulted from the NRC's decision with respect to the LWA and the schedule shift based on unforeseen conditions and circumstances that arose from the NRC decision up to the Board's decision in March 2010 to suspend the LNP until the receipt of the COL.

Q WHAT IS THE OVERALL CONCLUSION OF YOUR EVALUATION OF THE CONTINUATION OF LNP?

A. Based upon my review of the EPC Agreement, analysis of the evolution of the nuclear regulatory process since completion of Crystal River Unit 3, and its experience with the U.S. nuclear industry since the early 1970s, I have concluded that (1) it is reasonable for PEF to pursue the construction of new nuclear generation at this time, (2) the EPC Agreement terms and conditions that were preserved by the amendment to the EPC Agreement are beneficial to PEF and its customers, (3) as compared to EPC contracts for other recent mega projects, these beneficial terms and conditions are appropriate for the engineering, procurement and construction of the LNP, and (4) the decision by PEF to partially suspend LNP until receipt of the COL was an informed decision based on a rational, deliberate decision-making process and, therefore, was both reasonable and prudent based on the information known and that reasonably should have been known at the time the decision was made.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CHAIRMAN ARGENZIANO: Anything else? Okay. I guess we are ready for our next witness, Mr. Jon Franke.

THE WITNESS: Yes, ma'am.

CHAIRMAN ARGENZIANO: Hi. Welcome.

MR. WALLS: Mr. Franke, would you -- Mr. Franke was not previously sworn.

CHAIRMAN ARGENZIANO: He was not?

MR. WALLS: No, he was not.

CHAIRMAN ARGENZIANO: Okay. Would you stand, please, and raise your right hand. And you do not have to repeat after me.

I'm sorry, I started out the wrong way. I was put you -- get you onto a board. I used to do that a lot as a legislator, and I'd go around to different counties and put people on different boards, and I was going to give you a whole different thing to say. So let's not do that.

(Witness sworn.)

CHAIRMAN ARGENZIANO: Thank you. Proceed, please.

JON FRANKE

was called as a witness on behalf of Progress Energy Florida, Inc., and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WALLS:

Q. Mr. Franke, would you please introduce yourself and provide your business address?

A. Yes. My name is Jon Franke. I am the Vice President for the Crystal River Nuclear Plant. My address is 15760 West Power Line Drive, Crystal River, Florida 34428.

Q. And have you filed Prefiled Direct Testimony and Exhibits on March 1, 2010, and April 30, 2010, in this proceeding?

A. I have.

Q. Do you have copies with you?

A. Yes, I do.

Q. Do you have any changes to make to your prefiled testimony?

A. Yes, I have one correction made to a schedule. This is Schedule P-7 of my testimony. Actually, it's attached to Jeff Foster's testimony for which I sponsor. If you refer to Line 4 of that schedule, Column Gulf or G.

Mr. Rehwinkel, would you like for me to wait for you to get that? And this is a confidential number, but there should be a -- currently if you look at -- Mr. Rehwinkel, I will wait for you to find it -- it is Schedule P-7.

And, yes, we did discuss this in deposition, Column G. There is a number there that is zero in the current schedule. I have a corrected number. This was an error in the schedule. There is a total in Column Hotel which does reflect this number being in the column, so it does not change.

Now, this change is essentially an omission, but does not change any of the conclusions of the schedule. The number is later totalled in Hotel, so it does not effect any requirements or recovery or any changes in my testimony. It's just a detail that we identified during deposition. There should be a number. I have that number. It is confidential, and we can make it available to the parties afterwards.

Additionally, in my direct testimonies of March and April there are changes that have occurred subsequent. All answers at that time were accurate at the time of those deposition -- of that testimony. It's specifically two places they have changed. This has been updated in my rebuttal and in deposition. They refer to, one, the end of my current outage, which at different times, depending on when you asked me, based on our schedule at the time, we had different estimates of when the plant would return to service. It currently is expected to return to service in the fall of 2010.

And that leads to a change in our refueling outage 17, which will be fall of 2012 now. And, additionally, there were times where the license amendment request was projected to be submitted, and that has changed now. We are working with the NRC to develop the appropriate time to submit that license amendment request. And those dates I projected in earlier testimony are no longer accurate.

Q. With those changes, if I asked you the questions today would you give the same answers?

A. Yes, I would, with those changes.

MR. WALLS: We request that the prefiled testimony be moved in evidence as if it was read in the record today.

CHAIRMAN ARGENZIANO: So moved.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 100009

DIRECT TESTIMONY OF JON FRANKE

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jon Franke. My business address is Crystal River Nuclear Plant, 15760 West Power Line Street, Crystal River, Florida 34428.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") in the Nuclear Generation Group and serve as Vice President – Crystal River Nuclear Plant.

Q. What are your responsibilities as the Vice President at the Crystal River Nuclear Plant?

A. As Vice President – Crystal River Nuclear Plant, I am responsible for the safe operation of the nuclear generating station. The Plant General Manager, Engineering Manager and Training sections report to me. Additionally, I have indirect responsibilities in oversight of major project activities at the station. Through my management team I have about 420 employees that perform the daily work required to operate the station and provide engineering and training support to the station.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor's degree in Mechanical Engineering from the United States Naval Academy at Annapolis. I have a graduate degree in the same field from the University of Maryland and a Masters of Business Administration from the University of North Carolina at Wilmington.

I have over 20 years of experience in nuclear operations. I received training by the U.S. Navy as a nuclear officer and oversaw the operation and maintenance of a nuclear aircraft carrier propulsion plant during my service. Following my service in the Navy, I was hired by Carolina Power and Light and have been with the company through the formation of Progress Energy. My early assignments involved engineering and operations, including oversight of the daily operation of the Brunswick nuclear plant as a Nuclear Regulatory Commission ("NRC") licensed Senior Reactor Operator. I was the Engineering Manager of that station for three years prior to assignment to Crystal River as the Plant General Manager in 2002. Approximately two years ago I was promoted to my current position.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the Company's request for cost recovery pursuant to the nuclear cost recovery rule for certain costs incurred in 2009 for the Crystal River 3 ("CR3") Extended Power Uprate project. My testimony also supports the Company's request for a prudence determination of the costs incurred for the project in 2009.

Specifically, I will describe the construction costs incurred for which PEF is seeking recovery of the carrying costs. I will explain why those construction costs were reasonable and necessary to accomplish the uprate. My testimony further supports the prudence of those costs by describing the process by which vendors and technology were selected. I will also provide testimony regarding PEF's project management policies and procedures that are designed to manage project costs and maintain the project schedule and explain why they are reasonable and prudent.

Q. Do you have any exhibits to your testimony?

A. No, however, I am sponsoring the cost portions of Schedules T-4, T-4A, T-6, and Appendix B, and sponsoring Schedules T-6A through T-7B of the Nuclear Filing Requirements ("NFRs"), which are included as part of the exhibits to Will Garrett's testimony. Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period. Schedule T-4A reflects CCRC recoverable O&M expenditure variance explanations for the period. Schedule T-6 and Appendix B reflect the construction expenditures for the project by category. T-6A reflects descriptions of the major cost categories of the expenditures. T-6B reflects explanations for the significant variances between these expenditures and previously filed projections. Schedule T-7 is a list of the contracts executed in excess of

$1.0 million. Schedule T-7A reflects details pertaining to the contracts executed in excess of $1.0 million. Schedule T-7B reflects contracts executed in excess of $250,000, but less than $1.0 million.

All of these schedules are true and accurate.

Q. Please summarize your testimony.

A. The Crystal River Unit 3 Uprate Project ("CR3 Uprate") is expected to be completed in three phases and is expected to result in the Company generating an additional estimated 180 MWe of efficient nuclear power. The Company successfully completed the first phase of the project during the 2007 refueling outage, and it was brought online in January 2008. During 2009, PEF incurred reasonable and prudent costs to plan for and carry out the second phase of the project, which occurred during the 2009 refueling outage. PEF also incurred some costs in support of the third phase of the project, currently scheduled for the next CR3 refueling outage. This included incurring costs necessary to secure long lead-time equipment necessary for the phase 3 outage work. The work performed for the second phase of the uprate project was completed and the equipment was installed during the 2009 refueling outage. The CR3 unit is now in an extended outage but currently is expected to return to service in 2010. The extended outage at CR3 does not impact the uprate project construction costs, either for the 2009 work or the work to be completed during the next refueling outage. Progress Energy is presently reviewing the schedule for the 2011 outage and may decide to shift the outage to 2012. Such a shift would likely change the timing of some project costs.

As demonstrated in my testimony, and the NFRs filed as exhibits to Mr. Garrett's testimony, PEF took adequate steps to ensure that the costs it incurred were reasonable and prudent. When selecting vendors, PEF utilized a Request for Proposals ("RFP"), or competitive bidding, process where appropriate, and used reasonable business judgment to select sole-source vendors when an RFP was not possible. For all its contracts, PEF negotiated as favorable contract terms as it could given market conditions to provide reasonable cost certainty and appropriate risk-sharing. Accordingly, the Commission should approve PEF's uprate project costs incurred in 2009 as reasonable and prudent pursuant to the nuclear cost recovery rule.

III. DESCRIPTION AND STATUS OF CR3 UPRATE PROJECT

Q. Please explain when and how the CR3 Uprate project will be accomplished.

A. The CR3 power uprate project is planned for completion in three scheduled refueling outages for CR3. As I noted above, given the current CR3 outage, PEF may shift its scheduled 2011 refueling outage to 2012. If this occurs, PEF anticipates completing the third phase of the uprate during this outage. By completing this work during the times when CR3 will already be offline, customers receive the benefits of the CR3 Uprate project without incurring replacement energy costs.

Phase 1, the MUR, was installed during the 2007 refueling outage and went on-line on January 31, 2008. The MUR is a series of engineering analyses to measure the "secondary heat balance" with improved accuracy through modifications to plant instrumentation and associated calculations. The improved accuracy in measuring the secondary heat balance allows the rated thermal power to be increased by 41 thermal megawatts ("MWt") and plant electrical generation to increase by approximately 12 megawatts electric ("MWe").

Phase 2 of this project is a series of improvements to the efficiency of the secondary plant also known as the Balance of Plant ("BOP"). The current BOP phase 2 work was completed during the 2009 CR3 refueling outage. This work included fuels analysis, safety analysis and system and program reviews for the license application; project management activities, including project plans, governance and oversight to ensure reasonable costs; permitting activities to obtain environmental permits for facilities and other construction activities; labor costs associated with mobilizing and maintaining temporary facilities to house the extra personnel needed; and outage work including, among other things, installation of four moisture separator reheaters, two secondary cooling heat exchangers; two turbine bypass valves and mufflers; modification of the turbine generator electrical output bus duct cooling system; replacement of the turbine generator exciter; rescaled integrated control system; and installation of a fiber optic "backbone" to interface with the new turbine monitoring equipment.

The third and final phase of the uprate is to be completed during CR3's next scheduled refueling outage. At that time, PEF anticipates completing the remaining work necessary to provide the remaining 140 MWe power uprate, called the Extended Power Uprate ("EPU"). The BOP phase improvements were sized to support the EPU. The EPU maximizes the output of the reactor and the BOP to their ultimate estimated capacity.

The current Phase 3 scope of work also includes installing new, larger Low Pressure Turbines for the unit. Based on blade disc slippage during the manufacturer's bunker spin testing in April 2009, the Company decided to defer installation of the Low Pressure Turbine replacements at CR3. PEF is currently negotiating with the turbine manufacturer regarding the Low Pressure Turbines and evaluating its options for finalizing this part of the Phase 3 work.

The remaining phase of the CR3 Uprate project is currently on schedule to be performed during the next scheduled CR3 refueling outage.

Q. Have the improvements made with the BOP phase been completed?

A. Yes, the improvements were completed. The CR3 unit will return to service after the extended, unplanned outage because a delamination of the concrete in the containment building wall was discovered while work was being done for the Steam Generator Replacement ("SGR") project.

Q. Did the CR3 Uprate project work have something to do with the extended outage?

A. No. The delay is unrelated to the CR3 Uprate project.

Q. How did PEF choose the vendors with which it contracted during the 2009 timeframe?

A. PEF employed a competitive bidding process to choose the vendors with which it contracted in 2009 for the various projects associated with the CR3 Uprate project. PEF issued an RFP, evaluated the RFP responses based on a variety of factors (including price, dependability of the vendor, technical considerations, and the like), and chose the vendor that provided the best value for the price.

A detailed description of the contracts executed in excess of $250,000, including the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract, is contained in Schedules T-7 through T-7B, included in the exhibit to Mr. Garrett's testimony.

IV. COSTS INCURRED IN 2009 FOR CR3 UPRATE PROJECT

Q. Has the Company incurred costs for the CR3 Uprate project in 2009?

A. Yes, PEF incurred costs related to the last two phases of the CR3 Uprate project. The total capital expenditures for 2009, gross of joint owner billing and exclusive of carrying cost, were $118,140,493. These costs cover (i) license application costs, (ii) project management costs, (iii) permitting costs, (iv) on-site construction facility costs, (v) power block engineering, procurement and related construction costs, and (vi) non-power block engineering, procurement, and related construction costs. Schedule T-6A further details these costs.

Q. Please describe the total License Application costs incurred and explain why the Company incurred them.

A. The License Application costs reflected on the T schedules were $20,016,839. These licensing application activities are necessary to gain regulatory commission approval of the license change. These activities include fuels analysis, safety analysis and system and program reviews.

Q. Please describe the total Project Management costs incurred and explain why the Company incurred them.

A. The Company incurred Project Management costs of $21,154,156. The Company's Project Management costs include the following Project Management activities:

(1) project administration, including project instructions, staffing, roles and responsibilities, and interface with accounting, finance, and senior management;

(2) contract administration, including status and review of project requisitions, purchase orders, and invoices, contract compliance, and contract expense reviews;

(3) project controls, including schedule maintenance and milestones, cost estimation, tracking and reporting, risk management, and work scope control;

(4) project management, including project plans, project governance and oversight, task plans, task monitoring plans, lessons learned, and task item completions;

(5) project training, including the uprate project training program, training of personnel in accordance with the training program, and maintaining training records; and

(6) management of CR3 Uprate licensing work.

Each activity was conducted under the Company's project management and cost control policies and procedures that I describe in my testimony below. Such costs are necessary to ensure that the scope of work is adequate to achieve the uprate project objectives, that the engineering and construction labor, material, and equipment, provided by PEF or outside vendors for the project, is available when needed at a reasonable cost, and that the project schedule can be maintained.

The CR3 Uprate project was planned to be completed during the 2009 and 2011 CR3 refueling outages. Through the Project Management activities that I have identified, the Company successfully completed the 2009 work on-schedule. These necessary CR3 Uprate project costs are reasonable and prudent.

Q. Please describe the total Permitting costs incurred and explain why the Company incurred them.

A. Permitting costs incurred were $882,003 for permitting needs for 2009. These costs were necessary for the permitting activities to support the construction work in 2009. PEF incurred costs to develop the environmental report associated with the LAR. PEF also incurred Permitting costs to obtain the environmental permits for facilities and other construction activities. These Permitting costs were prudently incurred.

Q. Please describe the total On-Site Construction Facilities costs incurred and explain why the Company incurred them.

A. On-Site Construction Facilities costs incurred were $1,203,995. This represents the labor costs associated with mobilizing and maintaining temporary facilities to house the extra personnel needed to implement Phase 2 of the EPU. These On-Site Construction Facilities costs were prudently incurred.

Q. Please describe the total costs incurred for the Power Block Engineering, Procurement and related construction cost items and explain why the Company incurred them.

A. The Company incurred $71,243,000 for Power Block Engineering, Procurement, and related construction cost items. Most of the costs incurred in this category in 2009 were associated with the outage scope of work which included:

- Installation of 4 Moisture Separator Reheaters
- Installation of 2 Secondary Cooling Heat Exchangers
- Installation of 2 Moisture Separator Reheater Shell Side Drain Heat Exchangers
- Installation of 4 Turbine Bypass Valves and Mufflers
- Modification of the Turbine Generator Electrical Output Bus Duct Cooling System
- Installation of 2 Condensate Heaters
- Replacement of the Turbine Generator Exciter
- Turbine Generator Electrical Stator Rewind
- Rescaled Integrated Control System
- Installation of a fiber optic "backbone" to interface with new turbine monitoring equipment
- Installation of 2 Secondary Cooling Pumps and Motors
- Installation of a Turbine Lube Oil Cooler
- Installation of Heater Drain Valves
- Plant computer updates
- Facilities

PEF's 2009 Power Block Engineering and Procurement costs were necessary for the timely completion of the CR3 Uprate work during the 2009 refueling outage and the next planned refueling outage. These costs were prudently incurred.

Q. Please describe the total costs incurred for the Non-Power Block Engineering, Procurement and related construction cost items and explain why the Company incurred them.

A. These costs total $3,640,540. They are associated with the studies the Company completed on the effects of the increased heat at the Point of Discharge. These costs are necessary for the project because PEF will not be able to complete the full uprate without analyzing and accommodating the higher water temperature in the discharge canal. These costs were prudently incurred.

Q. How did actual capital expenditures for January 2009 through December 2009 compare to PEF's estimated/actual projection for 2009?

A. PEF's actual capital expenditures in 2009 were over PEF's estimated/actual projection by $602,941. This variance is primarily driven by additional Licensing Amendment Request preparation costs and Permitting activities partially off-set by Non-Power Block Engineering work. The variances are explained below.

At the time of the Estimated/Actual filing, the assigning of costs into the filing categories was based on general assumptions that were determined to be the most appropriate guidelines to assign costs to the categories at that time. As the project has matured and a more detailed task structure has been implemented, the Company established a new and more accurate method for assigning costs to the various categories. This change did not affect the total project cost or the total capital expenditure variance, but did affect variances within individual categories, particularly in Project Management, Power Block Engineering, and On-Site Construction Facilities.

License Application:

The 2009 License Application capital expenditures on the T-6 schedule were $20,016,839 with a total estimate of $16,277,263, resulting in a variance of $3,739,576. The actual cost of the License Amendment Request increased due to additional, more detailed information included in the LAR. During 2009, the Company convened a previously planned expert panel to review the LAR preparation. This panel was part of the project plan to ensure quality control of products and as a part of industry best practices. Further analysis and engineering work was conducted to increase the level of detail provided in the content of the Request and in the supporting documentation. The expert panel review determined that such changes in format and content would provide greater assurance of NRC acceptance and reduced review complexity, resulting in fewer Requests for Additional Information ("RAIs") and responses.

Project Management:

Project Management capital expenditures were $21,154,156. The original estimate was $39,666,137, resulting in a variance of $18,511,981. This variance is primarily driven by the new method for assigning costs to categories as discussed above.

Permitting:

Permitting capital expenditures were $882,003. The original estimate was $151,463, resulting in a variance of $730,540. The variance was primarily due to the need for environmental permits to support the project and temporary facilities that were not originally anticipated in the projected facilities plan.

On-Site Construction Facilities:

On-Site Construction Facilities capital expenditures were $1,203,955. The original estimate was $4,223,713, resulting in a variance of $3,019,758. This variance is primarily driven by actuals only capturing the labor to manage facilities work due to the change in method for assigning costs to the categories as described above. All costs to mobilize, rent, and maintain the temporary facilities needed to house the additional personnel for the EPU Phase 2 implementation that were estimated for this category are being appropriately captured in the Power Block Engineering category.

Power Block Engineering:

Power Block Engineering capital expenditures were $71,243,000. The original estimate was $52,560,048, resulting in a variance of $18,682,952. This variance is primarily driven by the new method for assigning costs to categories explained above.

Non-Power Block Engineering:

Power Block Engineering capital expenditures were $3,640,540. The original estimate was $4,658,928, resulting in a variance of $1,018,388. This variance is primarily driven by scope and schedule changes associated with Point of Discharge/Cooling Tower work. As the engineering evaluation of the New Forced Draft Cooling Tower progressed, the location of the tower was changed. The new location relieved the project of relocating a warehouse, thus reducing the project cost for 2009. Also in 2009, the recirculation line work that was scheduled to start was put on hold for further evaluation and rescheduled for 2010.

V. ALL COSTS INCLUDED FOR THE CR3 UPRATE ARE "SEPARATE AND APART FROM" THOSE COSTS NECESSARY TO RELIABLY OPERATE CR3 DURING ITS REMAINING LIFE

Q. Are the CR3 Uprate project costs included in the NCRC docket for recovery separate and apart from those that the Company would have incurred to operate CR3 during the extended life of the plant?

A. Yes, PEF has only included for recovery in this proceeding those costs that were incurred solely for the CR3 Uprate. In other words, the Company only included uprate costs that would not have been incurred but for the CR3 Uprate project. As stated in testimony provided in the last proceeding, PEF completed several scoping or feasibility studies to determine the exact nature of the changes necessary to implement the CR3 Uprate project. There are no costs included in the CR3 Uprate project that would be needed to continue the operation of the plant for an additional twenty years.

VI. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT

Q. Has the Company implemented project management and cost control oversight mechanisms for the CR3 Uprate project?

A. Yes. The Company is utilizing several policies and procedures to ensure that the costs for the CR3 Uprate project are reasonably and prudently incurred and that the project remains on schedule. The CR3 Uprate project is being undertaken by the Company consistent with its Project Management Manual, which has been in place at the Company and used to manage capital projects since early in this decade.

Additionally, because the CR3 Uprate project is a major capital project for the Company, the project must comply with the Company's policies and procedures in its Major Capital Projects – Integrated Project Plan that was issued in 2009. The CR3 Uprate project was also approved in accordance with the Company's Project Evaluation and Authorization Process. This evaluation and project authorization process has been in place at the Company for many years. Finally, the CR3 Uprate project is subject to the Progress Energy Project Governance Policy, which also has been in place for many years.

Q. Can you describe some of the project management and cost control policies or procedures in the Company's project management documents that are being used to manage the CR3 Uprate project and control project costs?

A. Yes. PEF has several control mechanisms in place to manage the CR3 Uprate project and the costs incurred on the project. By utilizing these policies, PEF is able to effectively keep the CR3 Uprate project on schedule and ensure that costs incurred are reasonable and prudent. Additionally, we developed new policies where appropriate to manage the project.

For example, the CR3 Uprate project management team conducts a wide variety of regular, internal meetings. These regular meetings allow the project management team to monitor the progress of the project, its costs, and to incorporate the collective knowledge and experience of the team in addressing the scope of the work, the cost of the work, engineering and construction implementation of the work items, and schedule performance. During these meetings PEF's project management team reviews team member roles and responsibilities, tasks are identified, and the necessary steps to implement the tasks, including incorporating lessons learned, are planned. Any staffing issues are discussed and addressed. Procurement under contracts, through the status of requisitions, purchase orders, and invoices for necessary engineering and material, is addressed as well as the status of administration of the contracts with outside vendors. Project training updates are provided. The status of work on the uprate licensing is regularly discussed. Risk management is discussed and addressed. Finally, project management expectations are communicated and implemented by the CR3 Uprate project management team.

PEF's CR3 Uprate project managers also meet regularly with outside contract vendors working on the project to review the contract scope of work, engineering and construction implementation of that work scope, and the schedule for the work under the vendor contracts. Project requisitions, purchase orders, and invoices are discussed. Project management expectations are communicated to the outside vendors. By maintaining supervision over the project, the project schedule, and the work performed by outside vendors, PEF is able to anticipate and manage scope changes, if any, and project expenditures.

There are other regular project reviews too. CR3 Uprate project managers prepare Project Cost Reports that include all contract, labor, equipment, material and other project cost transactions recorded to the CR3 Uprate project. Monthly Department Cost Reports reflecting department capital expenditures for the CR3 Uprate project are also prepared by the department managers and/or financial analysts. These reports are regularly reviewed by the CR3 Uprate project management team.

PEF also has monthly PEF Finance Committee meetings, in which management reviews the CR3 Uprate project costs. Prior to these meetings, responsible project managers and Finance Management for the organization review various monthly cost and variance analysis reports for the capital budget. Variances from total budget or projections are reviewed, discrepancies are identified, and corrections made as needed. The specific reports used are the Cost Management Reports produced by

PEF Accounting. All cost reporting for the CR3 Uprate project is tied back to the Cost Management Reports which are tied back to the Legal Entity Financial Statements. In addition to the monthly Finance Committee meetings, senior management will periodically review the CR3 Uprate project to monitor its cost and ensure that it is on schedule.

Q. Does the Company have any policies or procedures in place to assess and mitigate project risks?

A. Yes. PEF has a robust risk identification and mitigation process. The Company routinely assesses various project risks and assigns each risk with a probability of occurrence and level of importance in terms of effect on project schedule and cost. PEF then develops multiple mitigation strategies to eliminate or minimize the risk. The Company keeps detailed logs of these risk analyses, which are updated on a periodic basis. By utilizing this risk management process, the Company can effectively identify and prevent risk factors from affecting the project schedule and cost.

Q. Are employees involved in the CR3 Uprate Project trained in the Company's project management and cost control policies and procedures?

A. Yes, they are. PEF's project management team for the CR3 Uprate project has been trained in these Company policies. There are formal Project Manager qualification requirements for projects of various sizes as well as for other roles within the Project Team (Designated Representative, Field

Lead, etc.). Members of the CR3 Uprate project management team have experience implementing these project management and cost control policies and procedures successfully on other Progress Energy projects. Members of the Project Team also have been hired from other organizations bringing a rich mixture of experience to meet the project's demands.

Q. How has this experience helped the Company's employees with the project management of the CR3 Uprate project?

A. PEF incorporated lessons learned from its experience with the uprates at other Progress Energy nuclear plants. Having been through those uprates, the Company has valuable experience that the Company can rely on in the course of this uprate project. The Company's prior experience adds value to all aspects of this uprate project, including staffing, vendor relationships, scheduling, and cost management.

Q. You mentioned outside vendors on the CR3 Uprate project. How does the Company ensure that its selection and management of outside vendors is reasonable and prudent?

A. First, a requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist in Corporate Services, or field personnel on the CR3 Uprate project, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition.

The contract requisition then goes through the bidding or finalization process. Once the contract is ready to be executed, it is approved online by the appropriate levels of the approval matrix pursuant to the Approval Level Policy and a contract is created. Contract invoices are received by the CR3 Uprate project managers. The invoices are validated by the project managers and Payment Authorizations approving payment of the contract invoices are entered and approved in the Contracts module of the Passport system.

When selecting vendors for the CR3 Uprate project, as I indicated, PEF utilizes bidding procedures through an RFP process when possible for the particular services or materials needed to ensure that the chosen vendors provide the best value for PEF's customers. When an RFP cannot be used, PEF ensures that the contracts with the sole source vendors contain reasonable and prudent contract terms with adequate pricing provisions (including fixed price and/or firm price, escalated according to indexes, where possible). When deciding to use a sole source vendor, PEF provides sole source justifications for not doing an RFP for the particular work.

In some instances where a sole source vendor must be used, for example, the vendor selected has particular experience with the plant or the work required, thus making it advantageous for that vendor to accomplish the work. In other instances where a sole source vendor is selected, the vendor has a fleet contract (which was secured through an RFP prior to the CR3 project) in which it provides service for other Progress Energy nuclear plants. Because of this working relationship, and the vendor's ongoing knowledge of and experience with Progress Energy's nuclear plants, it is reasonable for PEF to continue working with these vendors.

The Company has a sole source contract with the vendor AREVA. Based on its association with Babcock Wilcox, the designer of the CR3 plant, AREVA has particular familiarity and experience with operations of the plant that makes contracting with them advantageous. Two amendments to the contract were issued in November and December 2009 respectively related to design and licensing engineering labor for uprate equipment and the LAR.

Q. Does the Company verify that the Company's project management and cost control policies and procedures are followed?

A. Yes, it does. PEF uses internal audits to verify that its program management and oversight controls are being implemented and are effective in practice. During the first quarter of 2009, an audit was conducted to review financial controls related to the Nuclear Plant Cost Recovery Rule for the CR3 Uprate project. These processes were found effective. On July 2, 2009, an audit was completed regarding the effectiveness of project management and cost management for the CR3 Uprate project. Areas needing improvement were risk management, earned value analysis and KPI reporting. The Financial Controls Internal Auditing Program, financial status reporting, and information and process management were found effective. As a result of the audit, observations and recommendations were provided for improvement. The Company implemented the recommended action plans, and action items with target dates prior to January 2010 have been completed. Additionally, the Company's project management policies themselves, included in the Company project management documents that I have described above, contain their own mechanisms to ensure that they are followed and effectively implemented.

Q. Are the Company's project management and cost control policies and procedures on the CR3 Uprate project reasonable and prudent?

A. Yes, they are. These project management policies and procedures reflect the collective experience and knowledge of the Company. As a result, Company employees have, in preparing the policies and procedures reflected in the Company's major capital project management documents that I have identified above, incorporated their experience and knowledge of project management policies and procedures that work within the Company and within the industry. These policies and procedures have also been tested by the Company on other capital projects. Any lessons learned from those projects have been incorporated in the current policies and procedures. We revised several of our project management policies in 2009 to incorporate lessons learned. We believe, therefore, that our project management policies and procedures are consistent with best practices for capital project management in the industry and are reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 100009-EI

DIRECT TESTIMONY OF JON FRANKE

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jon Franke. My business address is 15760 W. Powerline St., Crystal River, FL 34442.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") in the Nuclear Generation Group and serve as Vice President – Crystal River Nuclear Plant.

Q. What are your job responsibilities?

A. As Vice President I am responsible for the safe operation of the nuclear generating station. The Plant General Manager, Site Support Services and Training sections report to me. Additionally, I have indirect responsibilities in oversight of major project and engineering activities at the station. Through my management team I have about 420 employees that perform the daily work required to operate and maintain the station.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor's degree in Mechanical Engineering from the United States Naval Academy at Annapolis. I have a graduate degree in the same field from the University of Maryland and a Masters of Business Administration from the University of North Carolina at Wilmington.

I have over 20 years of experience in nuclear operations. I received training by the U.S. Navy as a nuclear officer and oversaw the operation and maintenance of a nuclear aircraft carrier propulsion plant during my service. Following my service in the Navy I was hired by Carolina Power and Light and have been with the Company through the formation of Progress Energy. My early assignments involved engineering and operations, including oversight of the daily operation of the Brunswick nuclear plant as a U.S. Nuclear Regulatory Commission ("NRC") licensed Senior Reactor Operator. I was the Engineering Manager of that station for three years prior to assignment to Crystal River as the Plant General Manager in 2002. Approximately one year ago I was promoted to my current position.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the Company's request for cost recovery pursuant to the Nuclear Cost Recovery Rule for replacement and modification of equipment at CR3 to support an increase in electrical generation power from the nuclear plant. My testimony supports the Company's actual/estimated and projected costs for 2010 and 2011, and explains why these costs are reasonable. Finally, my testimony explains why the Crystal River 3 ("CR3") Extended Power Uprate project ("CR3 Uprate") is feasible, pursuant to Rule 25-6.0423(5)(c)5, F.A.C.

Q. Have you previously filed testimony in this docket?

A. Yes, I filed testimony on March 1, 2010 in support of the actual costs incurred in 2009 for the CR3 Uprate project.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. __ (JF-1), a Table summarizing the Company's updated cumulative present value revenue requirements ("CPVRR") analysis of the fuel savings benefits of the CR3 Uprate; and
- Exhibit No. ____(JF-2), a list of the low pressure turbine alternative installation options evaluated by the Company.

Also, I am co-sponsoring portions of Schedules AE-4, AE-4A, AE-6.3 and sponsoring Schedules AE-6A.3 through AE-7B and Appendix B of the Nuclear Filing Requirements ("NFRs"), included as part of Exhibit No. __ (TGF-4) to Thomas G. Foster's testimony. I will also be co-sponsoring portions of Schedules P-4 and P-6.3; sponsoring Schedules P-6A.3 through P-7B and Appendix D & E of Exhibit No. ___ (TGF-5) to Mr. Foster's testimony; and co-sponsoring

Schedules TOR-6 and sponsoring TOR-6A TOR-7 of Exhibit No. _____(TGF-6) to Mr. Foster's testimony. A description of these Schedules follows:

- Schedule AE-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule AE-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule AE-6 reflects actual/estimated monthly expenditures for site selection, preconstruction and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.
- Schedule AE-6B reflects annual variance explanations.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.
- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Appendix B reflects the reconciliation of the beginning construction work in progress ("CWIP") balance for those assets placed into rate base that are not yet in service as detailed on AE-2.3.
- Schedule P-4 reflects CCRC recoverable O&M expenditures for the period.
- Schedule P-6 reflects projected monthly expenditures for preconstruction and construction costs for the period.
- Schedule P-6A reflects descriptions of the major tasks.

- Schedule P-7 reflects contracts executed in excess of $1.0 million.
- Schedule P-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule P-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Appendix D reflects the revenue requirements calculated for the period 2006-2011.
- Appendix E reflects the capital spend recorded for the period 2006-2011.
- Schedule TOR-6 reflects actual to date and projected monthly expenditures for preconstruction and construction costs for the duration of the project.
- Schedule TOR-6A reflects descriptions of the major tasks.
- Schedule TOR-7 reflects initial project milestones in terms of costs, budget levels, initiation dates, and completion dates.

These exhibits, schedules, and appendices are true and accurate.

Q. Please summarize your testimony.

A. In 2010, PEF incurred reasonable and prudent costs to complete work for the second phase of the CR3 Uprate project during the 2009 refueling outage called the R16 outage. PEF also reasonably and prudently incurred and will continue to incur costs in 2010 to move forward with work for the third and final phase of the project and to finalize the Company's License Amendment Request ("LAR") for the project and support that request before the NRC. Work on the final phase of the CR3 Uprate project and to obtain NRC approval of the LAR for the full uprate will continue in 2011 as PEF prepares for the next CR3 refueling outage and the completion of the CR3 Uprate project.

As demonstrated in my testimony and the NFRs filed as exhibits to Mr. Foster's testimony, PEF took adequate steps to ensure that the costs it incurred were reasonable and prudent. PEF has also provided reasonable projections for costs to be incurred during the remainder of 2010 and all of 2011 for the final phase of the CR3 Uprate project. These projected costs were developed using the best available information to the Company at this time and the Commission should approve PEF's projections as reasonable.

III. 2010 ACTUAL/ESTIMATED AND 2011 PROJECTED PERIODS

Q. Does the Company plan to incur costs for the CR3 Uprate project during 2010 and 2011?

A. Yes. PEF must incur costs in 2010 and 2011 to prepare for the last phase of the CR3 Uprate project, the Extended Power Uprate ("EPU") phase, which is scheduled for completion during the next plant refueling outage called R17. PEF recently decided that the R17 outage will take place in the spring of 2012. In 2010, PEF incurred costs to complete significant uprate work during the R16 outage. In 2010 and 2011, PEF will incur costs to: (1) continue the engineering design work for the third phase of the uprate to be completed during the next refueling outage; (2) provide detailed field implementation planning of the engineering design work; (3) complete and submit the EPU LAR to the NRC and work through the licensing review process with the NRC; (4) develop CR3 Uprate vendor oversight plans and schedules for the R17 outage manufacturing cycle; and (5) work on vendor selection and procure long lead equipment for the EPU work during the R17 outage. In 2011, PEF expects to complete the planning, long-lead equipment procurement, and preparation work for the installation of EPU equipment and other EPU work in time for the 2012 R17 outage.

Q. What is left to do in the third and last phase of the CR3 Uprate project to accomplish the power uprate?

A. We will complete the supporting engineering and design calculation work and install and test major components. Several new components will need to be installed. These components include two condensate pumps and associated motors, two booster feed pumps and associated motors, two feedwater pumps, two feedwater heaters, a high pressure turbine ("HPT") and the low pressure turbines ("LPTs"). Engineering design work is necessary to develop the specifications for this equipment and material. During this last phase new cooling towers will also be installed. Additional safety related equipment will be installed including a fast cool down system. At this time, the EPU work during the next refueling outage is estimated to take 45 days. This estimate will be refined as the 2012 outage date approaches.

Q. Why was the next CR3 refueling outage moved to the spring of 2012?

A. The CR3 unit is currently in an extended outage. Refueling outages at CR3 typically occur on an eighteen to twenty-four month cycle. The exact term of the refueling cycle depends on such factors as the most efficient use of nuclear fuel, the timing of required inspections and tests, the cost of replacement generation and Company resources. As a result of the current extended refueling outage at CR3, and taking into account these factors, the Company determined the most reasonable time for the next CR3 refueling outage is the spring of 2012. As we complete the current outage, this decision will continue to be evaluated.

Q. Was the current refueling outage extended as a result of the CR3 Uprate project?

A. No, it was not. The current extended outage occurred because of a delamination of concrete in an area of the containment building wall which was discovered while work was being done for the Steam Generator Replacement project during the R16 refueling outage. This event had nothing to do with the CR3 Uprate project work during the same refueling outage.

Q. Has the extended outage associated with the Steam Generator Replacement increased the costs of the EPU project?

A. The impact on overall project costs is minimal. The EPU project cost is expected to be impacted somewhat by escalations, maintenance of staffing levels, and storage of materials and equipment that were previously procured for the project. However, PEF does not expect any such impacts to be material given the relatively short delay of the R17 outage and no change in work scope.

A. **<u>Low Pressure Turbine Installation Deferral</u>**

Q. The Company originally planned to install new low pressure turbines during the R16 refueling outage. Did the Company do so, and if not, why?

A. No, the Company did not install new LPTs as initially planned during the R16 refueling outage. As I explained in my May 2009 testimony, the DC Cook plant in Michigan experienced problems with similar LPTs in September 2008 resulting in a forced outage and turbine repairs. Since the event at DC Cook, PEF has evaluated the technical issues surrounding the DC Cook problems, including a review of the root cause analysis undertaken by AEP, the owner and operator of DC Cook, and Siemens, the manufacturer of the LPTs in question. Based on that evaluation, it appeared to the Company that issues at DC Cook were sufficiently unique to that facility and its turbine operating characteristics that they were not a deterrent to installation of the planned LPTs at CR3. Accordingly, PEF planned to follow its initial plan of installing the new LPTs during the R16 refueling outage. However, two additional issues have arisen that have caused PEF to defer the installations until the R17 refueling outage. The first issue deals with the results of a performance test of the LPTs which occurred on April 29, 2009. The second issue is related to insurance coverage for the new LPTs.

Q. Please describe the issue related to the performance test of the LPTs.

A. During the manufacturer's bunker spin test of the last row of rotor blades for the LPTs designed for CR3, a blade row disk slipped. This test result was determined to be a manufacturing problem and not a design issue. Nevertheless, PEF determined that it would be prudent to exercise its rights under the equipment contract to require assurances from the manufacturer regarding the performance and reliability of the LPTs. On May 11, 2009, PEF sent a letter to the manufacturer requesting such assurances. In response the manufacturer has undertaken additional testing and has designed additional monitoring protocols. Information received to date appears to confirm PEF's initial assessment that the design of the LPTs is sound and that the failure of the bunker spin test was a manufacturing issue that can be corrected.

Q. Please describe the insurance coverage issue related to the new LPTs.

A. In the aftermath of the incident at DC Cook, Nuclear Electric Insurance Limited ("NEIL"), PEF's primary insurance carrier for its nuclear property, expressed concerns regarding the provision of coverage for LPTs similar to the ones that had been installed at DC Cook. PEF worked with NEIL to assess the issue and NEIL's current position is that it would only provide partial coverage for the new LPTs after 18 months of operation and full coverage after 36 months of operation. Specifically, NEIL has indicated it would not insure the last row (L0) blades. NEIL's position is based on the fact that, at this time, a definitive root cause for the DC Cook event has not been established. NEIL has not identified to PEF any design flaw or technical reason for limiting the coverage for the LPTs.

In light of NEIL's position on this matter, PEF has begun discussions with other insurance providers to assess the availability of alternative coverage for the new LPTs. The Company will also continue to discuss this matter with NEIL as circumstances develop that may alter NEIL's current stance.

Q. How did the issues related to the testing of the LPTs and insurance coverage for the LPTs effect PEF's plans regarding this equipment?

A. The Company concluded that it would be prudent, in light of these issues, and Siemens' inability to deliver the LPTs to support the original schedule for R16 per the original specifications, to defer the installation of the new LPTs until the next refueling outage. This decision will provide the Company with additional time to analyze the LPT issues further and to work with the turbine manufacturer to resolve any issues.

Q. What LPT options has the Company evaluated?

A. The Company's current plan is to install the new LPTs with the last row of blades in the next refueling outage. The Company has considered and evaluated alternative options for the LPTs as part of the CR3 Uprate project. As shown in Exhibit No. ___(JF-2), one option would be to continue to operate the existing LPTs. Option 2 is the original plan to install the full new LPTs with the last row of blades at the next refueling outage. Option 3 would be to install the new LPTs for the CR3 Uprate without the last row of turbine blades during the next refueling outage. Because the problem at DC Cook was limited to the last row of blades PEF believes that NEIL would provide full coverage for the new LPTs if they are installed without the last row of blades, but that configuration, would reduce the MW uprate for CR3. If the Company elects to install the LPTs initially without the last row of blades, the Company would still have the option of installing those blades during a subsequent refueling outage. Finally, the Company also considered installation of an alternative LPT design at a refueling outage following the next planned outage.

Q. What option did the Company choose and why?

A. The Company plans to install the 18 M^2 with the last row of blades as originally contemplated for the CR3 Uprate project. The installation will take place in the R17 refueling outage with the remaining EPU work. This will result in the full increase of approximately 180MWe for the CR3 plant when the EPU phase is completed and the plant is brought back on-line. As explained in the feasibility discussion below, PEF's customers would benefit from additional fuel savings over the remaining operational life of the nuclear unit regardless of what option PEF chose regarding the LPTs, but this option provides the most benefit.

Q. What types of costs does PEF project to incur for the CR3 Uprate project during 2010 and 2011?

A. As reflected in Schedule AE-6.3 of Mr. Foster's Exhibit No. __ (TGF-4), the total 2010 actual/estimated construction costs are broken down into six categories: License Application cost of $1.6 million; Permitting costs of $0.1 million; Project Management costs of $9.7 million; On-Site Construction Facilities costs of $0.7 million; Power Block Engineering, Procurement, and related construction costs of

$43.0 million; and Non-Power Block Engineering, Procurement and related construction costs of $11.3 million.

As reflected in Schedule P-6.3 of Mr. Foster's Exhibit No. __ (TGF-5), the 2011 projected construction costs are broken down into six categories: License Application cost of $0.5 million; Permitting costs of $0.1 million; Project Management costs of $4.7 million; On-Site Construction Facilities costs of $0.2 million; Power Block Engineering, Procurement, and related construction costs of $45.4 million; and Non-Power Block Engineering, Procurement and related construction costs of $16.9 million.

B. <u>Planned License Application Work</u>

Q. What Licensing Application work must be performed in 2010 and 2011?

A. For 2010, these costs include work to prepare and submit the Company's LAR to the NRC in support of the EPU for the CR3 Uprate. The LAR is necessary to complete the CR3 Uprate because PEF cannot operate CR3 at the increased megawatt level for the EPU without NRC approval. As previously discussed in my March 1, 2010 testimony, PEF contracted with AREVA to assist in preparing the LAR. Specifically, this work involved conducting engineering analyses and providing engineering support necessary for the preparation of the LAR content along with oversight and assistance in the actual preparation of the LAR document. PEF anticipates filing the LAR with the NRC by June 1, 2010. The NRC LAR review is expected to take 12 to 14 months with NRC approval well before the planned EPU work during the R17 refueling outage. For the remainder of 2010 and into 2011, PEF will work closely with the NRC throughout the review process, providing additional information and assistance as required. The License Application costs for 2010 and 2011 includes the work necessary to obtain NRC approval of the LAR.

PEF developed the License Application cost estimates using a reasonable licensing and engineering basis, with the best available information, consistent with utility industry standard cost estimation practices. PEF incorporated "lessons learned" on other LARs in its estimates of the cost to prepare the LAR and obtain NRC approval. PEF also used its engineering judgment and experience to determine the costs needed to ensure timely submittal and approval of the LAR. The 2010 and 2011 licensing application cost projections are, therefore, reasonable.

Q. Does PEF expect the NRC to approve the LAR for the CR3 Uprate in 2011?

A. Yes, it does. The Company expects its updated LAR to be approved in 2011 by the NRC following a typical set of requests for additional information ("RAIs"). PEF's LAR contains more detail and additional analysis than LARs previously submitted by other companies and approved by the NRC. PEF incorporated the "lessons learned" from these prior LARs in its LAR for the CR3 Uprate. The Company has also worked closely with the NRC and various outside experts to assure that the LAR contains sufficient detail based on present NRC standards to obtain NRC approval.

Q. What Permitting work was and will be done in 2010 and 2011 and why does the Company need to incur the cost of that work?

A. PEF expects work on a revision to CR3's Initial Site Certification, which represents an integrated environmental approval by federal, state, regional and local agencies. This revision to the Certification is needed to implement recirculation to intake if this option is pursued. To mitigate the additional heat generated at uprated conditions in the site cooling water discharge canal, an additional cooling tower will be constructed as part of the EPU project. The purpose is to maintain the cooling water temperature below the permitted maximum temperature at the point of return to the Gulf of Mexico. One feature of the new cooling tower is the return of a portion of the cooled water back to the plant intake canal to be reused in the plant's cooling systems. This feature will reduce the volume of water drawn from the Gulf of Mexico each day needed to support plant operation but must be certified via the revision to the Initial Site Certification. Additional permits or permit changes are also necessary to support operation of the currently planned new cooling tower at the Crystal River Energy Complex. As I explained last year, the Florida Department of Environmental Protection ("FDEP") approved the Company's application to construct this cooling tower. The additional permit work that is necessary in 2010 and 2011 to support the operation of the new cooling tower includes the canal interfaces reviewed by the Army Corps of Engineers, Environmental Resource Permits for percolation pond over-flow by DEP, and any National Pollutant Discharge Elimination System ("NPDES") changes that are addressed with DEP and the

U.S. Environmental Protection Agency ("EPA"). These permitting activities for the CR3 Uprate project are well underway and on-schedule to be completed before project completion.

PEF's estimates for the permitting work necessary for the CR3 Uprate project in 2010 and 2011 are based on PEF's experience with similar permitting work on this and other projects. PEF reasonably incorporated industry knowledge and experience in its estimates. As a result, PEF's cost estimates reasonably reflect the cost of performing the permitting work necessary for the CR3 Uprate project.

Q. What Project Management work was and will be done in 2010 and 2011 and why does the Company need to incur the cost of that work?

A. After successfully managing the completion of the CR3 Uprate project work in the first two phases during the 2007 and 2009 CR3 refueling outages, PEF will continue to manage the CR3 Uprate project through the successful completion of the EPU and final phase of the project in the next planned refueling outage. Project management costs are on-going as we wrap up the uprate project phase two work in 2010 and prepare for the uprate phase three work in 2012. Our project management costs include the activities conducted pursuant to PEF's project management and cost control oversight policies and procedures necessary to support, supervise and manage the final phase of the CR3 Uprate project. These project management and cost control policies and procedures were described in my March 1, 2010 testimony.

The Company's project management work consists of : (1) project administration, including project instructions, staffing, roles and responsibilities, and interface with accounting, finance, and senior management; (2) contract administration, including status and review of project requisitions, purchase orders, and invoices, contract compliance, and contract expense reviews; (3) project controls, including schedule maintenance and milestones, cost estimation, tracking and reporting, risk management, and work scope control; (4) project management, including project plans, project governance and oversight, task plans, task monitoring plans, lessons learned, and task item completions; (5) project training, including the uprate project training program, training of personnel in accordance with the training program, and maintaining training records; and (6) management of the CR3 Uprate licensing work. These activities are necessary to ensure that the CR3 Uprate project work scope, schedule, and cost to implement the work scope achieve the CR3 Uprate project objectives.

The CR3 Uprate project management cost estimates were developed using the best available information to the Company on the scope of the project management activities, our experience and "lessons learned" from managing the uprate and other projects, knowledge gained from industry and PEF best management practices. As a result, PEF project management costs for 2010 and 2011 are reasonable.

Q. What On-Site Construction Facilities work was and will be done in 2010 and 2011 and why does the Company need to incur the cost of that work?

A. The 2010 costs are related to demobilizing the facilities used during the fall 2009 refueling outage by EPU project staff. The 2011 costs are related to installing temporary equipment storage and personnel staging facilities in preparation for the 2012 outage.

PEF developed these on-site construction facilities cost estimates on a reasonable engineering basis, using the best available information, consistent with utility industry and PEF practice. Based on PEF's experience with other construction projects, which involve similar types of activities that are necessary before construction can commence, PEF developed reasonable estimates for the on-site construction facilities costs for the CR3 Uprate project. In addition, PEF has successfully completed phases one and two of the CR3 Uprate project and has added to its knowledge base regarding estimating personnel, building and other facilities necessary to accomplish the required scope of work. These costs are therefore reasonable.

Q. Please describe the total costs PEF will incur for the Power Block Engineering, Procurement and related construction cost items and explain why the Company needs to incur them in 2010 and 2011.

A. These costs include engineering, design specification of material, and equipment procurement costs associated with the CR3 refueling outage, R17 outage work scope, scheduled for spring of 2012. The work scope includes the HPT and LPTs.

This work also includes the specifications for and procurement of long lead materials including: feed water booster pump motors, condensate pumps motors, atmospheric dump valves, and safety related motor operated valves and low pressure injection system components, among other material and equipment, to be installed during the EPU phase.

This work scope is necessary to achieve the power uprate objectives of the CR3 Uprate project and therefore the costs of this work scope are reasonable and prudent. PEF projected its 2010 and 2011 power block engineering, procurement, and related construction item costs using actual contract figures and project schedule milestones. From existing contracts, PEF estimated the procurement and construction costs for the equipment not yet under contract. PEF expects to have the additional contracts in place by the third quarter of 2010. The procurement of material is scheduled with end dates selected to support pre-outage milestones established by outage and project management. For example, for the planned outage in 2012, PEF must order and make payments on certain equipment during a particular timeframe. These payment amounts and the times for payment will be set forth in various contracts, and these payment terms are used for the projections. The 2010 and 2011 power block engineering, procurement, and related construction item cost projections are, therefore, reasonable.

Q. What process does PEF employ to ensure that its vendor costs are reasonable and prudent?

A. First, a requisition is created in the Passport Contracts module for the purchase of services. The requisition is reviewed by the appropriate Contract Specialist in Corporate Services or field personnel on the CR3 Uprate project, to ensure sufficient data has been provided to process the contract requisition. The Contract Specialist prepares the appropriate contract document from pre-approved contract templates in accordance with the requirements stated on the contract requisition. The contract requisition then goes through the bidding or finalization process discussed below. Once the contract is ready to be executed, it is approved online in accordance with the Approval Level Policy and a contract is created. Contract invoices are received by the CR3 Uprate project managers. The invoices are validated by the project managers and payment authorizations approving payment of the contract invoices are entered and approved in the contracts module of the Passport system.

PEF is employing a competitive bidding process to choose the vendors with which it will contract in 2010 and 2011 for the EPU. PEF issues Request For Proposals ("RFPs"), evaluates the RFP responses based on a variety of factors including price, dependability of the vendor, technical considerations and the like, and then chooses the vendor that will provide the best value for the price. A list of contracts executed in excess of $1 million is included in Schedule AE-7 and a detailed description is provided on Schedule AE-7A.

Procurement under contracts, purchase orders, and invoices are all addressed on a regular basis by project management. The administration of contracts with outside vendors is constantly monitored. Project managers meet regularly with outside vendors to monitor work scope, implementation, schedule, and costs.

Q. Does PEF anticipate having any new sole or single source vendor contracts in 2010 and 2011?

A. At this time, PEF does not anticipate entering into any new single or sole source vendor contracts to complete the CR3 Uprate project.

Q. Are there any other costs included in the Company's projections for 2010 and 2011 for the CR3 Uprate project?

A. Yes, PEF projects that it will incur approximately $12.0 million in 2010 and $17.3 million in 2011, gross of joint owner billing and exclusive of carrying costs, to address the Point of Discharge ("POD") issue. As I explained above, a new cooling tower will be constructed at the Crystal River Energy Complex to eliminate the additional heat from the uprate project in the discharge canal. PEF currently expects to place the cooling tower in service before completion of the EPU work on the CR3 Uprate project during the next refueling outage in 2012. These POD costs are part of the Non-Power Block Engineering, Procurement, and related construction cost categories on Schedules AE-6 and P-6 of Exhibits Nos. ____ (TGF-4) and (TGF-5), respectively. These costs are necessary to achieving the objectives of the final uprate. The cost estimates are based on the Company's experience with similar projects and similar industry projects. The costs are therefore reasonable.

Q. Please describe the projected costs being placed in-service for the CR3 Uprate project in 2011.

A. Approximately $80.5 million on a system basis or $73.3 million of assets on a retail basis will be placed into service as reflected on Line 3 of Schedule P-2.3 of Exhibit No. __(TGF-5). This is net of joint owners and does not include AFUDC. These costs are primarily associated with the LAR which will allow the plant to operate the increased megawatt output from the EPU, and the POD Recirculation Line and Forced Draft Cooling Tower which will handle the additional heat output.

Q. Are the costs projected for the CR3 Uprate project in 2010 and 2011 separate and apart from those that the Company would have incurred to operate CR3 during the extended life of the plant.

A. Yes, they are. PEF has only included for recovery in this proceeding those costs that were incurred solely for the CR3 Uprate that would not have been incurred but for the CR3 Uprate project. There are no costs included in the CR3 Uprate project that would be needed to continue the operation of the plant for an additional twenty (20) years.

IV. TRUE UP TO ORIGINAL COST FILING FOR 2010

Q. Has the Company filed schedules to provide information truing up the original estimates to the actual costs incurred?

A. Yes, these schedules are provided in Exhibit No. _ (TGF-6) to Mr. Foster's testimony, Schedules TOR-1 through TOR-7.

Q. What is the current total project estimate, compared to the original estimate?

A. As reflected on Schedule TOR-7, the total current project estimate, exclusive of AFUDC and including fully loaded costs, is $418.6 million. The original estimate provided in the need determination proceeding was $381 million, which did not reflect the full "Financial View" or fully loaded costs but instead reflected the estimated direct costs. The original estimate inclusive of the indirect costs is $439.3 million as presented in Schedule TOR-7. As I explained above, we now have many contracts in place for the CR3 Uprate project work, and our current cost estimates are based on these contract costs and estimates of supporting project management and other work by PEF. Another change in the estimate is the elimination of the transmission costs that were included in the original estimate. The current total project estimate is, therefore, based on the best available information at the time of this filing.

V. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the CR3 Uprate project since the testimony you filed on March 1, 2010?

A. The Company has not implemented any additional project management or cost control oversight policies or procedures for the CR3 Uprate since the discussion of these procedures in my March 1, 2010 testimony.

As discussed in my March 1, 2010 testimony, the Company utilizes several policies and procedures to ensure that costs for the CR3 Uprate project are reasonably and prudently incurred. First, the CR3 Uprate is managed in accordance with the Company's Project Management Manual, which is used to manage all capital projects, together with the Company's policies and procedures for Major Capital Projects – Integrated Project Plan (scheduled to be updated on May 27, 2010). The IPP is being updated to account for changes in the work plan since the last update including the shift in the R17 outage schedule and the deferral of the LPTs.

The CR3 Uprate project is also managed in accordance with the Project Evaluation and Authorization process and subject to PEF's Project Governance Policy. In addition, the Company has many control mechanisms in place to manage project costs. PEF's project management team for the CR3 Uprate conducts regular internal meetings to monitor the progress of the project and its costs and to incorporate collective knowledge and experience of the team in addressing work scope, costs, the implementation of the work, and schedule performance. Project management team members continually review the project, including roles and responsibilities, and create and implement lessons learned on a continuing basis.

Procurement under contracts, purchase orders, and invoices are all addressed on a regular basis by project management. The administration of contracts with outside vendors is constantly monitored. Project managers meet regularly with outside vendors to monitor work scope, implementation, schedule, and costs. Project training is also provided on a regular basis.

In addition, there are other regular project cost reviews. Cost reports for contract labor, equipment, material, and other project cost transactions recorded to the CR3 Uprate project are regularly produced, updated, and monitored. Project management also regularly reviews the project Cost Management Reports produced by PEF Accounting. PEF also implements internal and external audits to ensure that its program management and cost oversight controls are being implemented and are effective. For 2010, two internal audits are presently scheduled on Florida Plant Cost Recovery and Crystal River 3 Extended Power Uprate.

In addition to the yearly audits on CR3 Uprate cost and activities, there are several Nuclear Oversight Committees that review the EPU on a continuing basis, including the Plant Nuclear Safety Committee ("PNSC"), the CR3 Nuclear Safety Review Committee ("NSRC"), and the Nuclear Safety Oversight Committee ("NSOC"). There is also the Nuclear Oversight Department that independently assesses CR3 performance including uprate activities.

We believe that our project management and cost oversight policies and procedures and are consistent with best practices for capital project management in the industry and are reasonable and prudent. PEF has employed these project management policies and procedures to successfully implement two phases of the CR3 Uprate project, during two separate plant outages, and completed the work scope necessary for the first two phases of the CR3 Uprate project.

VI. RULE 25-6.0423(5)(c)5: LONG-TERM FEASIBILITY OF COMPLETING CR3 UPRATE

Q. Did the Company prepare an updated feasibility analysis for the CR3 Uprate?

A. Yes it did. The CR3 Uprate project consists of three phases of modification and efficiency enhancements that will increase the power output of CR3 from about 900 MWe by 180 MWe to 1,080 MWe. The Company analyzed qualitative and quantitative factors to determine if the CR3 Uprate project remains feasible going into phase three. First, the Company performed a qualitative analysis of the technical and regulatory capability of completing the EPU. The second step was an updated, quantitative CPVRR economic analysis that included an update of the fuel cost savings to customers and an examination of the impact based on which LPT option is ultimately installed. This analysis was completed assuming a 2011 outage date. A shift in the outage date to 2012 will not materially impact these numbers.

Q. Is completion of the CR3 Uprate technically feasible?

A. Yes it is. The first two phases of the CR3 Uprate project have been successfully completed and all equipment has been installed with the exception of the installation of the new LPTs. Even pending completion of the third phase, PEF's customers will receive the benefit of an additional 16 MWe upon the restart of CR3.

Phase one, the MUR, was installed during the 2007 refueling outage and went on-line on January 31, 2008. The MUR is a series of engineering analyses to measure the "secondary heat balance" with improved accuracy through modifications to plant instrumentation and associated calculations. The improved accuracy in measuring the secondary heat balance allows the rated thermal power to be increased by 41 thermal megawatts ("MWt") and plant electrical generation to increase by approximately 12 MWe.

Phase two of this project was a series of improvements to the efficiency of the secondary plant also known as the Balance of Plant ("BOP"). The BOP Phase two work was completed during the 2009 CR3 refueling outage and included the installation of thirteen equipment items. This phase will provide an additional 4 MWe when the CR3 unit returns to service this summer.

The third and final phase is the EPU, which will include the installation of six major components, as well as significant engineering work, and the installation of cooling towers. The Company is confident these components and related material can be successfully installed and operate to achieve the full uprate. The Company completed several technical feasibility studies during 2009 related to the EPU components and the EPU work. These technical feasibility studies confirmed that the EPU components and work can be installed and the EPU achieved. Additionally, we have successfully completed two full phases of the CR3 Uprate project and, with the exception of the LPTs which were deferred, have successfully installed all necessary equipment on schedule with no material issues.

Q. Is the CR3 Uprate project feasible from a regulatory and legal perspective?

A. Yes. PEF believes that all legal and regulatory licenses and permits for the CR3 Uprate project can be obtained. The EPU requires a number of permits and license changes to support operation at the higher power level including environmental permitting and a LAR from the NRC. The Company's LAR is complete and ready to submit to the NRC. PEF plans to submit it to the NRC by June 1, 2010. Even though the LAR was completed in time for a March 31, 2010 submittal, because of the shift in the R17 outage schedule PEF decided to hold off on the submittal of its LAR. PEF utilized this additional time to review and monitor the progress of other LAR applications pending before the NRC and questions from the NRC on such submittals, and also conducted an additional expert review of its LAR. A June submittal still provides PEF 21 months before the planned R17 outage to obtain NRC approval of the LAR. The NRC commitment is to review and approve LARs in 14 months (12 months from LAR acceptance). Thus, ample review time is built into the schedule for LAR approval. Additional time is also provided in the event LAR revisions are necessary to address emerging issues. For example, Point Beach, also a Pressurized Water Reactor, is going through EPU review now. CR3 can take advantage of any RAIs and the responses thereto as lessons learned as it proceeds through its own LAR review with the NRC.

PEF is currently on schedule to obtain all necessary licenses and permits for the EPU. There is no reason to believe that the necessary licenses and permits will not be obtained and that the EPU cannot be achieved.

Q. What was the result of the Company's updated economic analysis of the CR3 Uprate project?

A. The updated economic analysis also demonstrates that the CR3 Uprate project is feasible. The CR3 power uprate will provide customers substantial fuel savings for the extended life of the CR3 plant and enhanced fuel diversity on PEF's system. In addition, PEF's customers receive additional, reliable base load capacity from the lowest cost fuel generation resource available to PEF. We expect that all of these benefits will be achieved and the full 180 MWe will be realized when the project is completed after the next CR3 refueling outage.

Q. Did the Company update its project costs for the economic analysis?

A. Yes, it did. The Company included its current estimated cost to complete the CR3 Uprate project in its analysis. As can be seen in Exhibit (TGF-6) Line 12 PEF's current estimate of total project costs excluding carrying costs and gross of joint owners is $418.6 million. When you pull out the joint owner portion shown on Line 15, this decreases to $387 million. Through February of 2010, PEF has incurred $215 million net of joint owners in costs. This leaves approximately $172 million of additional investment expected associated with completing the CR3 Uprate project. As explained more fully below, it clearly makes financial sense to move forward with the project.

The results of these analyses are included in Exhibit No. ___ (JF-1) to my testimony and the LPT alternatives under evaluation are identified in Exhibit No. ___ (JF-2) to my testimony. As demonstrated, the net present value of the fuel savings range from $474 million to over $801 million. The estimate to complete the CR3 Uprate Project is $172 million. As described more fully above, PEF's plan is to install the 18 M^2 LPTs identified as Option 2 in Exhibit No. _____(JF-1). Taking into consideration the additional spend needed of approximately $47 million for the 18 M^2 turbine option this option shows estimated NPV fuel savings of just less than $800 million and when compared to the remaining investment it is clearly beneficial to customers to move forward. The Company also analyzed the different LPT alternatives that the Company evaluated that I have previously described in the updated CPVRR of fuel savings analysis. The result of these analyses confirmed that PEF's customers will benefit from additional fuel savings over the remaining operational life of the nuclear unit regardless of what option PEF chose regarding the LPTs. Directionally, the fuel savings versus cost to complete the project utilizing these alternative options also shows favorability. All viable options for installing new LPTs of the same or another design will achieve fuel savings.

Q. Did the Company consider the environmental emission benefits from additional nuclear generation in its quantitative analysis of the feasibility of the Uprate project?

A. No. The Company performed its updated CPVRR analysis in the same manner that it performed the initial CPVRR analysis for the CR3 Uprate project during the determination of need proceeding for the project. This analysis compared the costs of the project to the fuel savings benefits only. Because the fuel savings benefits of the project exceeded the project costs on a net present value basis there was no need to consider the further benefits of additional nuclear generation from the project. Similarly, when we updated the CPVRR analysis the fuel savings benefits still exceed the costs to complete the project on a net present value basis so there was no need to quantify further the benefits of the project.

This does not mean those additional benefits do not exist. The CR3 Uprate project will provide additional carbon-free, clean nuclear generation from the lowest cost fuel source available to the Company. This additional nuclear generation will add to the Company's fuel diversity and reduce its reliance on fossil fuels. As a result, implementation of the CR3 Uprate project is an important element of Progress Energy's Balanced Solution.

Q. Is continuing the CR3 Uprate project through completion of the EPU phase in the best interest of the Company and its customers?

A. Yes, it is. The CR3 Uprate remains feasible and will benefit the Company and its customers as I have discussed. As a result, the Company remains committed to completion of the CR3 Uprate project.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. WALLS:

Q. Do you have a summary, Mr. Franke?

A. Yes, I do. There was one other change we made in deposition, but it is worth mentioning here, as well. I apologize. In my March 1 testimony on Page 2, I indicated on Line 16 that I had been promoted to my current position two years ago. And as Mr. Rehwinkel pointed out, it was actually only one year ago. So that two on Line 16, Page 2, should be a one. And I do have a summary I prepared.

Q. Will you provide the summary, please.

A. My name is Jon Franke, the Vice President for the Crystal River Nuclear Plant. My March 1, 2010, Direct Testimony explains the prudence of costs incurred in 2009 for the Crystal River 3 extended power uprate project. My April 30th, 2010, direct testimony explains the reasonableness of the company's actual and estimated 2010 costs and projected 2011 costs for the project. I also provide testimony regarding Progress Energy Florida's project management, contracting, and oversight controls for the uprate project in 2009, and explain why they are reasonable and prudent.

The Crystal River 3 uprate project divides up the work necessary to generate an additional estimated 180 net megawatts of electricity of nuclear power in three separate planned outages when the unit is already off line in conjunction with refueling operations. The company successfully completed the first phase during the 2007 refueling outage, and the second phrase of work during the 2009 refueling outage. That equipment installed in 2009 will be tested upon return to service of the plant following the current outage.

Progress Energy Florida incurred reasonable and prudent costs in 2009 to plan for and carry out the second phase of project work. Progress Energy Florida also incurred costs in support of the third and final phase of the project in 2009, and will continue to incur costs for this work in 2010 and 2011. This work is scheduled for the next Crystal River 3 refueling outage after the current extended outage ends.

There are no increased costs in this proceeding due to the extended outage of the unit at this time. The uprate project costs in 2010 and '11 are necessary to complete the final phase of work and, therefore, are reasonable. I'm available to answer questions related to my testimony.

CHAIRMAN ARGENZIANO: Thank you.

MR. WALLS: We tender Mr. Franke for cross.

CHAIRMAN ARGENZIANO: Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Madam Chairman.

CROSS EXAMINATION

BY MR. REHWINKEL:

Q. Good afternoon, Mr. Franke.

A. Good afternoon, Mr. Rehwinkel.

Q. I'm going to ask you some questions directed to your direct testimony. Some of these questions may delve into areas that morph into your rebuttal testimony, and I'm indifferent as to whether you want to answer them in this round or in rebuttal, but I would prefer that as long as there is continuity of the questioning that we can ask questions now, but I leave that to you.

A. And I will be receptive. I have a copy of my rebuttal, as well. It is our intention for me to come back later again for rebuttal testimony.

Q. Okay. I don't intend to refer to your rebuttal, but if we get into a subject matter there, we'll just see where it goes. Thank you.

A. Yes, sir.

Q. Turning to your March 1, 2010, Direct Testimony on Page 14.

A. Yes.

Q. You testify there that for 2009, the license application capital expenditures were $20,016,839, is that correct?

A. That is correct.

Q. And you also testify on Line 17 that your project management capital expenditures were $21,154,156, is that correct?

A. That is correct. And realize that those are large general titles of scope of work. So, for example, the licensing application expenditures include other engineering work which overlaps with that licensed application. They're broad categories.

Q. Now, would you agree -- wouldn't you agree that these two dollar amounts that we have addressed for 2009 are the most relevant to the issue of the LAR and the engineering work related to the CR-3 uprate project?

A. Yes, they speak to those two areas primarily. Although, there is some power block engineering listed on Page 15, Line 16, that relate to engineering work associated with the power uprate, as well.

Q. Okay. Isn't it true that the CR-3 uprate was a project that was initiated in late 2006 by the company?

A. Excuse me. I'm sorry, I did not understand your question.

Q. Isn't it true that the CR-3 -- well, let's step back. The uprate that we are talking about is planned for three phases, correct?

A. Yes, sir.

Q. The measurement uncertainty recapture, which has already occurred and went into -- I guess, you had power ascension for that project in early 2009?

A. That is not correct. The equipment was installed in the fall of 2007. The license amendment was achieved after that outage, and we actually increased the power, I believe it was late January or early February of 2008.

Q. I see.

A. So we actually achieved the power in 2008.

Q. I meant 2008.

A. Yes, sir.

Q. Okay. And then Phase II was the balance of plant phase that was originally intended to achieve -- was it 28 megawatts?

A. The original scope -- and there's a little misnomer. The subsequent two outages included work which would be characterized as balance of plant. The work in 2009 was exclusive to the balance of plant. There is some balance of plant work in my next outage. However, there were original designs early in the project to achieve a four megawatt increase due to thermal efficiencies associated with -- it's a technical piece of equipment. It's a moisture separator reheater, drain reheaters. That was installed in 2009. Additionally, we were at -- much prior to our last outage, we had planned to install low pressure turbines which were projected to get about another 24 megawatts of thermal efficiencies out of the steam plant.

Q. Okay. So, essentially, the intent was for Phase I and Phase II to yield an additional 40 megawatts with Phase III to yield 140 megawatts for a total of 180, is that correct?

A. That was the original plan, yes, sir.

Q. Okay. And that entire plan was approved by management in late 2006, is that correct?

A. Yes, that sounds about right. I don't remember the exact date, but I'm confident it was 2006, and I believe the need was approved around that same time frame.

Q. Okay. Now, isn't it true that the original budget for the entire plan was on a direct view basis $427 million?

A. Let me refer to --

Q. Okay.

A. The best place in the testimony to look at that would probably be TOR-7.

Q. Okay.

A. Yes, I believe the -- hold on. Yes, I believe the correct number originally, once burdened, you know, there was direct, and then there is direct plus overhead costs, essentially, was 439.3. That would be apples-for-apples for comparison of the needs case. I believe the actual number in the needs case was 15 percent below that because of the burdens, as we have explained in subsequent years of true-up was not included in that original estimate.

Q. Okay. So looking at Schedule TOR-7.

A. Yes, sir.

Q. We see the $439.3 million number that you referenced, and part of that, $102.4 million of that says transmission facilities, is that correct?

A. Yes, sir. Absolutely; yes, sir.

Q. Now, isn't it true that not long after that $439 million number was developed and the project authorized that you realized that you didn't need the transmission facilities after all, correct?

A. I would say that this project has had a number, a large number of increases and decreases in scope. This particular schedule does detail the transmission decreases that did occur. There are also a large number of, as we moved through a more clearer and finalized understanding of what would be required, there were additional components that were taken out of scope, additional components that were added to scope, systems added to scope that were not part of this original feasibility.

So, yes, it did include the transmission costs. It also included other components that are now out of scope, and a large number of components and system changes required once we worked through the engineering that are not on this original estimate.

Q. Okay. But the direct answer to my question -- and you are a very responsive witness. I know you understand the yes or no, and then the explanation.

A. Yes, sir.

Q. Is that very soon after this estimate was developed that you realized that you did not need the transmission facilities, correct?

A. That is correct. One of the first changes in the project was a better understanding of the transmission needs, and these transmission changes were not required.

Q. Okay. And isn't it also true that the transmission system is -- I hope this word is accurate -- agnostic to how the kilowatts are generated?

A. No, I can't say that, unfortunately. There is a lot of special needs to the transmission system for a nuclear plant, and I'll give you a couple of examples.

The safety features of Crystal River 3 requires a certain voltage support and a certain ability to withstand a trip of the unit so that it doesn't cause a subsequent loss to the grid in the vicinity of the nuclear plant. So there are very specific needs from a nuclear safety standpoint.

Additionally, and it will become important in this, it is important to this particular project, we also have rules associated with the transmission's ability to withstand the loss of the unit, so that the loss of a single unit does not cascade to a larger loss of other units and large sections of the grid.

As we complete this uprate, I believe Crystal River 3 will be the largest generator on the grid, and that subsequently changes transmission need. So, no, there are very clear ties between transmission needs and the nuclear plant in both directions. The transmission's ability to support the plant and the transmission system's ability to withstand the loss of the plant to the grid.

Q. But there was nothing about the engineering of the plant or the rescoping of the uprate project that made the transmission needs go away, was there?

A. It was a better understanding of those interplays I just discussed. Early on there was a belief -- this is one of those conditions where when you're studying the feasibility of a project this large, you make assumptions based on a feasibility level of understanding of the engineering work required to complete the activity.

In this case, the feasibility study pointed to a weakness in the transmission system that would have to be upgraded. Once the need was approved and the budget was approved to go forward with those engineering studies -- obviously, you can't spend a lot of money until the money is budgeted and approved. We discovered that there were ways to work around not having to expend those resources, and we constantly do that. We look for ways to provide the needs of the uprate in conjunction with the needs of the plant at a lower cost. And in this case we were able to find a way to install the uprate without these transmission costs. And we are going to continue to do that.

Q. Okay. But I guess my question is isn't it true that the way you engineered the uprate did not affect the need for the transmission facilities, isn't that correct?

A. Well, I'm not sure how to draw the line, Charles. I mean, I guess, we clearly had to do engineering analysis, sir, to understand relative to this uprate what its impact on the transmission. So in some cases engineering work identifies a need to install new equipment or change existing equipment. In other cases that engineering work provides the basis for not doing those upgrades or those changes.

In this case, that engineering work had a conclusion that this work was not required. So it was part of the project, but it did not require significant changes to the plant once that engineering work was completed.

Q. Let me ask it this way. Maybe this will get to the heart of the question that I have. A significant aspect of the engineering work that is related to this uprate project is designed to allow you to increase the thermal output of the reactor and the plant, correct?

A. That is correct. There is a portion that is improving the efficiency of the existing reactor output. In other words, get more electricity for the same reactor power. And then there is a second piece that is an actual increase in the reactor power, and then you have to install additional equipment or larger, more higher capable equipment to be able to accommodate that higher reactor power and turn that into electricity.

Q. And you have to do all of that within the rules and regulations that the NRC oversees and get their approval, correct?

A. For that second piece, yes. The thermal efficiencies typically can be -- they're still under the NRC rules, but they do not require, and I think your question is they do not require prior approval by the NRC. There are still rules that apply to the installation of modifications, however, those rules allow the installation without prior NRC approval.

Q. Okay. So the vast majority of the engineering costs that have been incurred and you expect to incur in this project will be related to the increase in the thermal capabilities of the reactor as well as the efficiencies of the plant based on those increased thermal capabilities, correct?

A. That's correct, those two pieces.

Q. So those aspects of the engineering, the increase in the thermal output of the reactor and the increase in the efficiency of the plant based on that increased thermal capability had no bearing on the need for the transmission facilities, correct?

A. That's not true. The transmission needs are reflective of how much output the plant achieves, so it is independent of the reactor power. So let me see if I can explain this. If you follow the original plan as you stated earlier, the original plan was to increase the reactor output about 40 megawatts prior to receiving the change in our license which allows us to increase the thermal output of the reactor. So those 40 extra megawatts electric would have to be reviewed against those transmission needs, and the needs of the plant with regard to the transmission system at the site. So even just those first 40 megawatts electrically are important to the plant from a safety standpoint. We would have to perform engineering to verify that they were okay for the plant to be able to generate.

Q. Okay. But you did not perform any material engineering tasks related to increasing the thermal efficient output of the plant or the efficiency of the plant once you increased that thermal output that caused the need for the transmission facilities to go away, did you?

A. We made no physical modification to the plant which accommodated the relief from any need to perform transmission work. That was engineering analysis alone. So, essentially, we sat down with pencils and calculators, updated the electrical grid model that we used, and we were able to find a way to not have to make significant modifications to the transmission system.

Those studies aren't cheap. They take a little bit of time and some money. So we worked through those and determined that it was not required.

Q. Okay. Now, on this same Schedule TOR-7, which is Page 9 of 9 of Mr. Foster's TGF-6.

A. Yes, sir.

Q. In the middle of the page under initial milestones there is an item that says point of discharge, $49.5 million. Do you see that?

A. Yes, sir.

Q. And that is a cooling tower project to allow you to increase the thermal output of the plant and stay within environmental regulations, is that correct?

A. That's correct. Various changes that we are making in a minor way the thermal efficiencies, but in a major way the increase in reactor power will drive more heat into our circulating water system which heats up our discharge canal. And as such, we have to still accommodate our environmental permit with the state which limits the temperature on the outfall of the plant, and this is a cooling tower to accommodate that.

Currently we have cooling towers which cool this discharge canal, and so this is a modification to increase the capacity of that cooling capability on the discharge canal to accommodate the higher level of heat primarily for summer months.

Q. Okay. Now, have there been any changes in the company's plans with respect to the need to install point of discharge facilities?

A. Right now it is in our plan and in our schedule to install this design. We have, over the last year, and I think I talk about it in our testimony and it is reflected in the schedules, we have deferred some of the costs associated with that due to the extended nature of the current outage.

Since my current extended outage has carried me through the summer of 2010, I will not expect to achieve the higher power level until I return to service in the fall of 2012. That means that this cooling tower need, once again it's for an environmental permit, would not need to be in service and cooling the canal until, you know, prior to the heat of the summer months in 2013. So we have changed the schedule, but our current plan is to still install this cooling tower.

Q. Okay. So you don't anticipate the need for the cooling tower to go away, is that correct?

A. As I explained with the transmission earlier, we will continue to monitor for places where we could decrease the costs of this project. We are continuing to monitor the environmental regulations that may impact this, any changes to our position with regard to meeting those, and if there is a way to reduce this scope we can, but for right now our plan is to install these cooling towers.

Q. Okay. When we discussed this issue in your deposition, my impression was that the entire need for the POD, or the point of discharge facilities might go away. Was that a mistaken impression on my part?

A. No, just the complete answer is we are going to continue to monitor the need for this part of the project, and it may change. But as of right now the current decision is that this is part of the project and will continue forward.

Q. Okay. So, now, if the costs related to the POD facilities are deferred until 2013 --

A. Yes, sir.

Q. -- that would be outside of the currently planned refueling outage, R-17, which you testified would be the fall of 2012, correct?

A. That's correct.

Q. Would these costs still be submitted for cost-recovery?

A. If they are required to achieve the uprate, yes, they would.

Q. Okay. Now, are any costs associated with point of discharge in any estimate for the years 2010 or 2011?

A. I believe they are included as we deferred them. The deferred costs are still in those 2010 and '11 estimates, yes.

Q. Okay. By the way, when you mention the fall of 2010 for returning to service for your unit --

A. From the current outage, yes, sir.

Q. Yes. My thinking of fall is that it goes through, I guess, the middle of December. Winter starts in the middle of December around --

A. In Florida it's probably a little wider than most states, but I think the most accurate description is we expect to return in the fourth quarter of 2010.

Q. Okay. And when you say your LAR, did you say that you thought you had filed that with the NRC in the fall of this year, as well?

A. Yes, and we talked about this in deposition. I think the best answer is we are working through an issue we discussed in deposition with the NRC. They continue to, you know, change their regulatory position with regard to a number of items. We monitor that very closely as we always have. The same testimony I provided last year. We are going to sit back, and we want to submit the license application at the right time. There is no correct time. In sitting back and taking advantage of this delay in need for the license application during this year, we have identified a new element of the license application based on very recent licensing action the NRC has taken, and we are currently in the process of making a decision for how to change our license application. We have identified a need to change it.

And once we are through our project control process where that change goes through management for approval, and actually in conjunction with that, we will continue to work with the NRC as to when the appropriate time to submit that license extension is. It could be as early as this fall. It might be as late as next spring.

I need to work through that process to finalize when that date is. It would be imprudent for me right now to submit it under the current new regulatory environment. We are going to submit it at the right time so that it will be accepted by the NRC.

Q. Okay. So today is the first time you have testified that it could be sometime in 2011?

A. That's correct.

Q. Okay. You're aware, I take it, that Florida Power and Light recently withdrew, very recently withdrew their license amendment request from the NRC?

A. I'm aware of that; yes, sir.

Q. Do you have any opinion about the impact of that on this project?

A. Actually, we have been monitoring the St. Lucie application, as well as the other on-going applications with the NRC, and we have applied the lessons of those submittals to our application as we have gone. And my staff informs me that any lessons learned have already been applied to the current status of my license application that would be learned from the St. Lucie application.

Q. So it's your testimony today that you believe the withdrawal by Florida Power and Light will have no impact on the way you present your, or you prepare and present your LAR to the NRC?

A. I would say it already had some impact, but that I don't foresee any future impacts due to the St. Lucie withdrawal. And we have looked at this.

Q. Okay. And since your deposition there is no change in your assessment of the digital instrumentation issue with respect to your license amendment preparation?

A. Yes. I believe it's still the same status as the deposition. That was only a week and a half ago.

Q. Yes.

A. We are continuing to define the correct solution. We know there are solutions to dealing with the digital modification and its acceptance in licensing space, so now we are currently in the process of choosing what that solution will be, making a recommendation to management, developing any schedule and cost impacts that might have on the total project.

I am very confident that the potential changes in both schedule and cost would still bound that this is a feasible project. It's just a matter of which solution do we choose and how it affects cost and schedule.

Q. Have your staff prepared any estimates of what cost might be for any engineering change that are associated with this?

A. I have seen no cost estimates yet.

Q. Okay. Do you have any rough idea of what they might be?

A. I know that I am confident -- the best answer to that is I am confident that there is no way they can get to the point where they would affect the feasibility of this project based on how cost-effective this project is to our customers in net present value. It's impossible for it to get that high to where it would ever become a material question.

Q. Okay. You did not have a direct role in the preparation or the decision-making in 2006 with respect to this license amendment -- I mean, this EPU for CR-3, did you?

A. I would say no direct role. I was the plant manager at the time working with the team. I was part of the management team which was presented the project, but at that time the project reported through a different chain.

Q. Okay. So you didn't have any direct decision-making role with respect to how to proceed with this project, is that correct?

A. No, sir, but I am here to represent the company's decisions with regard to the project all the way back to those dates.

Q. Okay. And it's true that the original plan was to have the full 180 megawatts from the extended power uprate implemented and power ascension by the end of 2011, correct?

A. Yes, sir.

Q. Can you -- I'm asking it to you in an open-ended way. Can you state for the record, if it's not confidential, what the current budget for the overall project is?

A. I don't think the overall number is necessarily confidential. And you have to be careful because the schedules that we provide relate to NCRC costs. There are portions of this project which are being covered under the environmental cost-recovery clause, so sometimes we get wrapped around what that total number is, but I believe the -- and as we discussed earlier, it gets complicated when you talk gross joint owner or independent joint owner, but the total project, I believe, is 481.5 million.

Q. Is that net of joint owners?

A. That is net of joint owners, and it looks like --

Q. But it includes AFUDC, correct?

A. Yes, I believe it does. It's hard to get that.

Q. Okay.

A. The financial view total net of joint owners before AFUDC looks like it's 479.4.

Q. Okay. And isn't it true that the budget for -- the approved cost estimate for the EPU project increased $52.8 million in the third quarter of 2009?

A. Yes. We went through a budget process where prior to this the costs had come down because of scope changes like the transmission project, and then as we were finalizing the engineering work required for the next phases, we recognized additional work which would be required to be performed, and that added costs back into the project to the tune of 52.5 million.

Q. Okay. Now, the original -- if I look on Page 9 of 9 of this TOR-7, without transmission facilities, I see $287.5 million, is that correct, in the initial milestones column?

A. Yes, that's correct.

Q. Okay. Now, if you ignore transmission facilities, that number is directly comparable to the $481 million number you just mentioned, isn't it?

A. No.

Q. Why not?

A. Well, if you are going to take transmission costs out, you have got to add up the other things that we learned since the time the transmission was removed. I mean, to pick a particular portion of the project and cut it out and say, well, you know, I'm going to take advantage of saying your costs should be reduced because that one had to be done once you learned more is not an apples-for-apples comparison if you are going to, you know, blind your eyes to the case where that same engineering work or other engineering work in support of the project identified additional cost requirements of the project.

So, you know, if you want to choose a single project that ended up with a cost decrease and not reflected by that engineering work, I don't think it's a fair comparison to then compare that number to other engineering work which identified additional scope requirements.

Q. But in this TOR-7 schedule, it's true, is it not, that below the line of total, there is a separate and distinct line that says transmission facilities, correct?

A. It does. And I could have rewritten this TOR-7 to have sliced and diced this project into the 40 or 50 different subprojects required at the time, and you would see a large number of projects that were on one line and not on the other. In some cases those line items might be in the future number. In other cases they might be in that previous number. So I guess what I'm saying is to the detail that this schedule defines what is in that, the number you referred to, which is the 287.5, I believe you could -- you know, I could take that 287.5 and add another four or five sublines to it, and so it's just the matter of detail provided in the schedule, Mr. Rehwinkel.

Q. But you agree that the transmission costs, the $102.4 million that are here were not part of the integral engineering solutions related to the increase of either thermal output of the reactor or electrical efficiencies of the plant itself?

A. I apologize, I must not have been clear when you asked that question before, Mr. Rehwinkel. No, it was. You can't increase the reactor power without addressing the transmission needs. So it was part of the project to increase reactor power, absolutely required scope to understand the transmission needs of the higher power level of the plant. And some money was spent with regard to that. It was only engineering money; it was not physical changes.

And just as we had to evaluate those transmission needs, we had to evaluate the feed water heater needs, for example. A year ago we thought we had to replace two feedwater heaters. Now we believe we have to replace four. We thought that there was a need to change our SERC water intake pumps. We decided that was not required.

I have got a list of probably 20 or 30 decisions like that where scope was brought in or taken out. Our original scope, for example, was 287.5 million, and did not include a safety-related cross tie in our low pressure injection system. We now know that is required, and the cost associated with that item, had I broken it out before, is about $16.2 million currently. So there would have been no money for that in the 287.5, but there would be in this current 360.1.

Q. But you would agree, would you not, that there were no R-16 or R-17 scope changes that even came close to $102.4 million in any discrete engineering solution?

A. No one solution, but you add up all those changes, additions and minuses, yes, it didn't quite come to the 102.4, because you'll notice that the 439.3 is still above the original number, apples-for-apples, between the need and the current budget when you go apples-for-apples is still -- what is that, not quite $21 million below that original needs.

So we have taken 102 out. We have added a number of projects. The total numbers float around, but when you get to the end of the day we are still in the same ballpark, which is pretty good for a project this size.

Q. Isn't it true that within the company there is an emphasis on meeting the budget that's established in the IPP?

A. You know, the purpose of the IPP is to create a budget, and then changes as the project goes forward are reviewed through our management chain and through our project controls process so that those changes are appropriate and adequately managed. It is never the expectation of a project manager on a project like this to assume that a feasibility budget is what he should be held accountable to four years later.

It's difficult to hold any project manager accountable or project that the scope is not finalized on. And at the point of a feasibility study you know what you know. Your intention is to spend the appropriate amount of time to get a strong sense of what the total cost will be. You always know there will be scope increases and decreases, and we hold them accountable, and you should be happy I hold them accountable to what the best lowest cost and successful conclusion to meet the project goals.

So in this case, if you look at TOR-7, if I merely was holding accountable to that original budget, he would have an extra $20-something million in his pocket to spend, and we're going to be holding him accountable to the 418.6. If that scope changes, we will hold him accountable based on what we think is the prudent cost for that new scope.

Q. And that would be true if the transmission facility item of $102.4 million was truly a need for the uprate project, correct?

A. Yes. But if I'm going to take the 102 away, I've got to give him the money back for the other increases in scope, just as I took money away for decreases in scope.

Q. The company has an internal audit function called the audit services division, is that correct?

A. Yes, sir.

Q. ASD. And ASD conducts periodic audits of projects like the uprate project, correct?

A. That's correct.

Q. And one of the functions they look at is cost management and adherence to the budget, correct?

A. Yes. I would not characterize it necessarily as adherence to the budget. I would call it adherence to the project management guidelines. Should they see that a budget is being exceeded or running under budget, they would refer back to our project controls procedures and ensure that the adequate approvals for those budget changes were occurring. So I would say they are more holding them accountable to the project controls function than necessarily to budget numbers.

Q. Okay. And on Page 23 of your Direct Testimony, if I could direct you to Line 16 on down, you do cite for the Commission's consideration the prudence of the costs that you are seeking the customers to pay for that you have an internal audit program that facilitates your management and oversight controls, isn't that correct?

A. Yes, sir.

Q. And the costs of those projects are rolled up, to some degree, in the costs that you seek recovery for here, correct?

A. I'm not sure -- I kind of lost your question there.

Q. I'll withdraw the question.

But you do offer this function for the Commission to support your cost-recovery here?

A. Yes. Part of our project controls function is inclusion of our audit program as part of the oversight of the project, yes, sir.

MR. REHWINKEL: Madam Chairman, at this time I would like to offer an exhibit for cross-examination purposes. And if you will give me one second.

CHAIRMAN ARGENZIANO: Sure.

MR. REHWINKEL: Madam Chairman, this is a document with a short title that says CR-3 EPU LAR Events Outline.

CHAIRMAN ARGENZIANO: Very short. Can we shorten it? And you need a number on this exhibit. Were we at 193?

MR. REHWINKEL: 193.

CHAIRMAN ARGENZIANO: 193. Thank you.

(Exhibit 193 marked for identification.)

CHAIRMAN ARGENZIANO: And, again, this is confidential where highlighted.

MR. REHWINKEL: Yes. This is a document that the company has taken the effort to highlight, and I think the only confidential information is shown on Pages 2, 3, and 4. Actually, 2, 3, 4, and --

CHAIRMAN ARGENZIANO: Uh-huh. That's all I have.

MR. REHWINKEL: Yeah. It says confidential at the top of Page 5, but there is no highlightings there. So you will see dollar amounts, only dollar amounts and one percentage amount that are confidential.

CHAIRMAN ARGENZIANO: Okay.

BY MR. REHWINKEL:

Q. Mr. Franke, are you familiar with this document?

A. No, I'm not, but I'm trying to get familiar as I sit here.

Q. Okay.

A. I'm familiar with most of the items listed in it.

Q. Okay. Well, this is a document, as you can see from the bottom -- you recognize this numbering 10PMA-DR4 CR-3. This is Data Request Number 4 related to CR-3 that was submitted in this docket by the staff auditors. Do you see that?

A. (Indicating affirmatively.)

Q. I'm looking at the numbering at the bottom.

A. Yes.

Q. Okay. All right. Now, there is -- it says, G-I-N-N-A, that is Ginna, right?

A. That's correct. That's a correct pronunciation.

Q. Okay. Ginna is a reactor, a plant that you modeled your initial LAR development efforts after at the suggestion of the NRC, correct?

A. That is correct.

Q. Okay. And this shows that the Ginna LAR was approved in July of 2006, correct?

A. Yes, that is correct.

Q. And shortly thereafter, Progress -- it says Progress Energy CEO in December 11, 2006, authorized the CR-3 EPU project, is that correct?

A. That's correct.

Q. Was that Mr. Lyash in late 2006?

A. No, that was not. I believe actually this would have -- I'm not sure exactly when our CEOs changed. It was probably -- it was either Bill Johnson or his predecessor.

Q. Okay.

A. This is Progress Energy CEO, not Progress Energy Florida.

Q. Oh, I'm sorry. This is not -- okay.

A. Well, I believe Mr. Lyash's name was on that form, as well.

Q. Okay. Now, Ginna, what type of reactor was at Ginna?

A. Ginna is a Westinghouse, an early Westinghouse design reactor.

Q. Okay. It's not the same kind as Crystal River?

A. No. It's a pressurized water reactor. We got into this last year. There is no such thing as an exact replica reactor to CR-3 or any reactor in the United States. Ginna is a pressurized water reactor, so -- in general, there are two types of light water reactors in the United States, pressurized water reactors and boiling water reactors. Ginna was one of the early pressurized water reactors to seek an extended power uprate.

Q. Okay. Now, at the time you conceived the EPU project, your anticipated filing of the LAR with the NRC would have been in June of 2009, correct?

A. I can't remember if it was June or August, but in the summer of 2009.

Q. Okay. And at some point after that, you changed that date to September of 2009, correct?

A. Yes.

Q. Okay. And then after September of 2009, the LAR submittal date became February of 2010, correct?

A. Yes. The date of the LAR continued to move as we monitored the success and failure of other licensees with regard to our submittals and looked for feedback from the NRC on those license submittals so that we could incorporate the latest lessons.

Remembering that there is not a specific date that you want to submit the LAR. Early is not good. You want to submit your license application at the point where, one, you would, in a best case, receive approval prior to the equipment being installed that you could take advantage of it; and, two, late enough so that you can incorporate the most amount of lessons learned so that the application has the best chance of being received and accepted for review by the NRC.

Q. Well, what you don't want to do is to spend all the money to engineer the solution to operate the plant and then not be able to send power because you don't have a LAR, correct?

A. Well, it's impossible to do what you just described. The premise of what you just said is impossible. You have to expend a tremendous amount of engineering, the vast majority of the engineering to support the LAR application. If you look carefully at those units which have had their license amendment applications rejected for review, including the peer utilities, the reason was that there was insufficient engineering review performed prior to that submittal.

So, you can't have both. You have got to do the engineering to submit the LAR, and the LAR can't exist without the engineering. So in a perfect world I wouldn't have to spend any money. I could just submit the LAR and they would approve it. But you have got to spend the money to get the LAR.

Q. I think -- I didn't mean to ask the question that you answered, I apologize. My question was you would not, as far as the timing of your LAR --

A. Yes, sir.

Q. I mean your -- or your license amendment, actually, is what you are looking for. The LAR is the request, and the amendment is what you get from the NRC if you are successful, correct?

A. Yes. The LAR is -- the long word for LAR is license amendment request. So this is an amendment to your license from the NRC. It's like a driver's license. It's a little more exhaustive to pass the test, but it is a license to operate the reactor. This is an amendment to that license.

Q. Okay. So what I meant was you wouldn't want to spend all the money to engineer the solutions to make your plant capable of increasing thermal and electrical output, but not have the license amendment in hand so you could ascend the power to where you wanted it, correct?

A. The nature of your question -- you are asking an impossible wish. You know, it's like telling me I would like to eat my steak and not pay for it. Okay. I can't get my license without spending that money to do that engineering work. What you are asking me is wouldn't it be nice if you didn't have to do the engineering work to get your license. But the answer -- the only fair answer is I can't get my license without doing that engineering work, so I have to pay for it.

Q. Okay. My question is you would want to have an amendment in hand at the time you've completed all the engineering and your last outage so that you can get the additional megawatts out of the plant, right?

A. Well, maybe I'm -- we are getting crossed in words. The objective would be when you -- when you are ready to increase power, you would like to increase power as early as you can. Now, there are two trails you would have to walk down to get to that increase in power on an uprate like we are talking about here. One trail is a licensing trail, which says I've got to walk through the engineering work and the licensing work to submit the license application from the NRC, work through their review process and get approval of the LAR.

The other trail you have to walk is all the modifications and installation activities so that the plant, once that license application is received, is capable of generating that electrical power. Many plants have gotten to the end point of both of those walking paths at different times. I know of examples where plants have installed the equipment and not yet received the LAR, and then they got the LAR and they increased power subsequent to the receipt of the paperwork, but that engineering and that installation of equipment had already occurred. That happened to me at Brunswick when I was at the Brunswick Nuclear Plant. It's happened at a number of other utilities. Or you receive the license application prior to that last outage which installs those last components, maybe a month ahead of time, maybe six months ahead of time. But in any case you have got to walk both of those paths, both requirements have to be met to achieve the power increase.

Q. I noticed that you pulled out a copy of the CR-3 IPP to look at a budget number earlier?

A. Yes, I did.

Q. And you would agree with me that in each of the last three IPPs you have a chart that has milestones on it, correct?

A. Yes.

Q. And every single one of those milestones shows the company receiving the license amendment prior to the completion of all the uprate work, correct?

A. That is correct.

Q. And that's what you want to happen; that's the most efficient way to do it, correct?

A. It's really not a matter of efficiency. Okay. Let me make sure I'm clear here. You don't want to delay the power increase. So our position all along has been conduct the modifications, because most of the cost of the modification work is required to submit the license application anyway, and it provides a higher level of assurance that the license application will be received. Continue with your licensing activities, so at the end you've completed both.

Now, the timing is driven in two ways, I would say. Primarily, it's driven by refueling outages, when your outages will be. So, for example, we knew that it would take two outages to install all the equipment associated with Phases II and III of the uprate. You would like to complete at the end of that second outage the actual power increase to the new power level, so it would be nice to have that license application ahead of time.

However, there's a whole second set of standards that have to be achieved on that licensing side. And the timing of approval of that licensing depends on everything from ongoing regulatory environment, how much information you know when with regard to the engineering and design work associated with those modifications. So it's really both timelines you have to look at. You would like to be able to do it as soon as possible for both cases.

Q. Okay. And originally when you conceived this plan in December of 2006, the target date for receiving your license amendment would have been June, correct -- for submitting, it would have been June 2009, correct?

A. Yes, sir.

Q. And your expectation would have been 12 to 14 months for the NRC to act on your amendment request?

A. Yes. The Commission is unofficially committed to a 12-month review, and they can take traditionally about two months for a good application to review it for acceptance review. That can be extended to four in cases where the license application has a lot of questions, so you are talking about 14 months, in general, from sending it to the NRC. For a good application, they should be able to accept it within two months. If they've accepted it within two months, their general rule is that they will have it approved in a year.

Q. Okay. And that would have put you in -- sometime in late 2010, is that correct?

A. That's correct.

Q. And that was the plan?

A. That was the original schedule.

Q. Okay. Now, the scenario is that due to a certain set of circumstances, some of which are outlined in this document that we are discussing, you could possibly submit your LAR as late as the spring of 2011, correct?

A. That's correct.

Q. And perform your remaining work in Phase III, including what was left from Phase II, in the fall of 2012?

A. That's correct.

Q. And you could conceivably be without a license amendment at the time that work was complete for Phase III, correct?

A. Well, I want to be totally transparent with regard to this issue. Okay. It is a little more complicated than you've described.

If I submit it in the spring of 2011, I would expect that license prior to the start of my 2012 outage. Fourteen months from the spring of 2011 is the summer of 2012. So it still would be prior to that 2012 outage.

Now, in complete transparency, this digital modification piece has changed the game somewhat. The NRC, as reflected in a license that was approved earlier this year, has taken a position with regard to Interim Staff Guidance 6, which is guidance documents on how to review and approve digital instruments. Okay. This interim staff guidance has an allowance for review for digital equipment of any nature in an NRC application to take not 12 months, but longer than that. So in this case we are kind of in a new box. And even with regard to Interim Staff Guidance 6, we'll be applying for a license under a program the NRC has called a topical.

In this case there is a topical report on the equipment we may choose. We have not finalized that decision. So we have got to work through what that actual schedule with the NRC may be. This is a little new ground for the NRC. They have got the guidance out there. They have applied it to one licensee. There is another licensee that they are in the works with right now, but each of these cases will be special.

I think looking at the specifics of our application and the needs of the digital licensing, I think we probably have the simplest application and the least complex due to what we are trying to license and how it applies to the plant. I would rather not go into a lot of detail there, but I do believe ours is one of the least complex ones they will have to review. But an actual schedule is going to have to be something we work through with the NRC and understand what that schedule is.

Q. Okay. Thank you. We have already -- I think you've already indicated that the license amendment related to the measurement uncertainty recapture was not received prior to your ability to ascend power, is that correct?

A. Prior to the physical plant being modified to accommodate the change, yes. We had completed the physical plant modifications, and I believe it was a couple of weeks later we received the license application, the license amendment itself.

Q. Isn't it true that at the time -- that in December of 2006, that the Progress Energy CEO formally authorized this CR-3 EPU, that the company knew that this would be the first extended power uprate for Progress Energy Florida?

A. There is only one nuclear plant in Progress Energy Florida. This is the first extended power uprate for Progress Energy Florida, certainly not the first for Progress Energy, Incorporated.

Q. Okay. And isn't it also true that at that time, in December of 2006, that you knew that your only possible contractor for this job, AREVA, had never done an extended power uprate for this type of reactor?

A. Yes. To be specific, AREVA owns the proprietary knowledge required for submittal of a power uprate to the NRC for a large portion of the extended power uprate work. And so, yes, this was the first time AREVA had preformed an uprate on their B&W units.

Q. Okay. And management was aware of that?

A. Yes, sir.

Q. Okay. And at that time, December of 2006, you were also aware that this would be the largest extended power uprate at a B&W reactor, a Babcock and Wilcox reactor, correct?

A. We were aware of that, yes. It takes us about 7 percent above the largest output for a similarly designed plant.

Q. You were also aware that this would be the largest percentage uprate of any pressurized water reactor, correct?

A. I can't say I was aware of that. I don't know that that's true.

Q. Was management aware that this would be the first Babcock and Wilcox reactor taken above 3,000 megawatts?

A. That sounds right. Davis Bessey is a very similar plant to us. They operate about 7 percent below, and were originally licensed at that level, I believe, about 7 percent below where we are shooting for with this license application. I don't have their thermal megawatt number memorized.

Q. The NRC made note of that after your April 2008 meeting, correct?

A. I'll have to take your word for it.

Q. Okay.

CHAIRMAN ARGENZIANO: Mr. Rehwinkel, I hate to do this, but I have a request for just a short break.

MR. REHWINKEL: Sure.

CHAIRMAN ARGENZIANO: Is that okay? We will take a five-minute.

(Recess.)

CHAIRMAN ARGENZIANO: Okay. Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Madam Chairman.

BY MR. REHWINKEL:

Q. Mr. Franke, I would like to take a quick run through this document, which is 193, Exhibit 193. Do you still have that in front of you?

A. The 193?

Q. Yes.

A. I know you were working on that with Mr. Foster.

Q. I'm sorry. This is the LAR Events Outline, the one that we are --

A. Okay. The same one that we were looking at before?

Q. Yes.

A. Yes, sir.

Q. And mindful when we get to the Pages 2 through 5 that there is confidential information highlighted.

A. Yes.

Q. This document shows a projection, in the May 2009 item, a projection of a spend for EPU project costs, is that correct, related to LAR activities?

A. Yes, it does.

Q. Okay. And on the next item down there, June 29, 2009, you reference a Point Beach LAR submittal and some relation to an FPL supplement. Do you see that?

A. What was the date?

Q. I'm sorry. It's just below that of June -- I'm still on Page 2, June 29, 2009?

A. Yes, I do understand that.

Q. Okay. Now, the FPL supplement, is this an issue that was related to FPL's withdrawal of their LAR?

A. Recognize that this -- this is talking about Point Beach.

Q. Yes.

A. I believe the withdrawal you were referring to earlier was St. Lucie.

Q. Okay. There was just a reference to FPL in this paragraph here, and I didn't know if there was -- if Point Beach was referencing a supplement that FPL filed? If you don't know, it's fine, I don't --

A. I'm not certain. I believe Point Beach is an FPL plant, also. It's just not under the purview of this Commission.

Q. Okay.

A. And as such, this is referring to Point Beach's FPL application.

Q. Okay. Thank you.

A. There are similarities between this and St. Lucie.

Q. Okay. On the next page, on Page 3, there is a reference to the EPU project management team, and that is Crystal River EPU project management team, correct?

A. Yes, sir.

Q. It says, "Assembled an expert panel to review the current status of the LAR presentation activities, and to provide feedback to EPU management on the increasing industry standards associated with the NRC licensing activities." Is that correct?

A. Yes, sir. The timeline with regard to that, that's when the team assembled. The plan to do that expert panel was well ahead of that date.

Q. Okay. Is there a document that you have been able to identify or locate that demonstrates that this expert panel was something that was always planned?

A. I haven't looked, to be honest. We can go look for that if you'd like. I do know that we had discussions about the need for an expert panel and the need to self-assess and review our application. Remember, this expert panel was an internal assessment planned by Progress Energy because of a lot of the issues you described earlier concerning the fact that this was the first AREVA extended power uprate, and one of the early PWR extended power uprates, and that it was -- this is not a simple license application you're doing. So for anything this large, you are going to want to set up a self-assessment program that makes sure that you take advantage of company internal resources and industry experts. That's just the way we do business.

Q. Well, if your expert panel was something that was long planned --

A. Yes, sir.

Q. -- why would you long plan for them to provide feedback on increasing industry standards associated with NRC licensing activities? You wouldn't have known that when you planned it, would you?

A. That's not the sole purpose of that expert panel. I mean, they certainly were given the task in July to make sure that our license application in light of what our own licensing team was beginning to see was taking advantage of those earlier applications of the other utilities. So that particular scope I don't think was identified months ahead of time. But, you know, this is the way we do business. We are constantly looking for ways to improve, where we can improve our performance, and a function of that is to step back and say, okay, when are you doing something special, new;

incorporate into that plan the need to self-assess and bring to bear experts that you have and maybe in the industry to make sure you are doing it in the best manner possible. That is what our expert panel was.

It was designed to be as we were receiving the inputs from AREVA and our own staff, to go back and sit down. This is a case where you are taking inputs from a large number of people, and you want a core team of experts to sit down and go through it and provide feedback as to how you're doing. That is just the way we do business. This self-assessment kind of program is something that is engrained in everything we do.

Q. Well, isn't it true that you had already in your timelines for the EPU project already had planned a site review that was different from the expert panel review?

A. Absolutely. And the reason for that is the licensed application itself is not from AREVA. It is from Progress Energy. We are the ones who acting as Florida Power Corp under the license own the license to operate Crystal River 3. As such, any work performed by AREVA would have to be reviewed by my own staff prior to my signature for submittal to the NRC. So that's part of the engineering process. What I'm talking about with regard to the expert panel is part of our assessment process, our oversight of that engineering process.

Q. Isn't it true that the document that the expert panel produced in a management debrief dated July 14, 2009, did not mention AREVA's work product relative to increasing industry standards associated with NRC licensing activities?

A. I would have to refer to that. I was present at that debrief. I don't remember what was mentioned in every slide. I know it is part of the docket. It has been added as part of this docket.

Q. Okay. But isn't it true that an internal review was conducted as a result of the results of the expert panel presentation?

A. Let me talk through this event. We had an expert panel review. Its design was to go into the license application and review it for its acceptance to NRC standards. I would have expected, and we did ask for that team to look at does this license application meet the standards for acceptance by the NRC, and are we on track for submitting a high quality license amendment request. That expert panel found some real problems, real issues with this license application that needed resolution.

Fundamentally what it found was that we had not been putting enough company resources and enough outside resources on the project to ensure success. We hadn't been spending enough money on it. And, quite frankly, we should have been ahead of some of these issues and identified them a little built earlier. And that is what that expert panel review concluded.

As such, we followed our corrective action program, which is when we find a problem, we generate a nuclear condition report. And then that requires an investigation to determine what lessons to learn from that expert panel review.

So first we identified some real issues. That is what that self-assessment program is designed to do, issues that we should have been able to prevent. We went into our corrective action program to understand and learn every lesson we could from that so that going forward we could correct the mistakes and get the license application in the right format prior to submittal.

MR. REHWINKEL: Thank you.

Madam Chairman, I'd like to offer an exhibit for cross-examination purposes, and it's the June 17, 2008, CR-3 EPU Management Presentation. I believe I need a number for that.

CHAIRMAN ARGENZIANO: 194.

(Exhibit 194 marked for identification.)

MR. REHWINKEL: This document does contain confidential information.

CHAIRMAN ARGENZIANO: Thank you.

BY MR. REHWINKEL:

Q. Mr. Franke, while it is being passed out, are you familiar with this document?

A. I looked at it last night, but prior to that I had not seen it.

Q. Okay. Well, I hope I can ask you questions about it that you will be able to answer.

This document would -- it looks like it is a presentation to Progress Energy management related to the EPU project made by Danny Roderick (phonetic).

A. Yes. The management review meeting program at this point in time would have been a presentation by Danny Roderick's organization to his boss. It is possible that my boss at the time, Dale Young, who was the Vice President at the time may have been present, and usually other senior managers from the nuclear group would have been present for this review.

Q. Okay. On Page 34.

A. Yes, sir.

Q. This document shows the budget for the project in 2008, is that correct, at $461 million?

A. I'm looking at Page 34, and I don't see that.

IPP update March 2008, yes, 461 million. I'm not sure what EAC means.

Q. Okay. And it shows initial authorization November, 2006, 493 million up at the top of that page. Do you see that?

A. Yes, sir.

Q. Okay. So in 2008, 461 million would have been kind of the controlling budget amount for this project, right?

A. Yes. The only thing that's not detailed here -- I think what this shows is the trend, you know. I think I mentioned earlier that the costs were decreased at first from the original authorizations where the need was based at a higher number and then came down initially, and then as we learned more we added money back in. That is what this is showing.

What I would be careful in characterizing these numbers is there's a lot of factors here. First of all, this point of discharge mitigation that is listed on the slide is that portion of the total budget which is not covered by the nuclear cost-recovery. So these numbers don't necessarily reflect directly to this hearing, because there's a good portion -- in fact, I believe two-thirds of that particular modification is recovered under a different clause. It is recovered under the environmental clause.

And what I don't know is are these numbers inclusive or exclusive of joint-owner costs and whether or not they are -- well, financial view means it's burdened, so it is not direct costs. So I know that at least the number in 2006 is burdened, and I don't know how AFUDC is treated in these numbers. So, you know, I can say that this is showing a trend. I can't say that 461 relates to any specific number in this hearing.

Q. Okay. But you would agree, would you not, and your testimony to the Commission would be such that you don't manage a project with any greater or less scrutiny or oversight based on which clause or which cost-recovery mechanism you bring to the Commission for approval with, do you?

A. No. You were just asking me about the number, and I'm trying to make sure that I carefully quantify what that number means to me.

Q. Okay. On Page 36 of this presentation, this is at the time would have been the planned schedule for this project, correct, or a graphic representation of that schedule?

A. It's a Level I schedule, which means that it is a very high level overview.

Q. Okay. But midway down the page there is -- on the left-hand side it says, EPU R-17, correct?

A. Yes, sir.

Q. And that is the third phase of the EPU, correct?

A. Yes, although there are -- I'm just trying to make sure. It is the third, the third phase -- R-17 was the third outage of the implementation and the third phase.

Q. At this time?

A. Yes.

Q. Okay. And there is a line here that's -- I apologize, it's kind of difficult to read, but the line that's right under EPU R-17 says engineering review of NSS. That's the nuclear safety --

A. Nuclear steam supply system. It's the reactor side of the plant.

Q. Okay. Chapter 14, Analysis and LAR Preparation. Do you see that?

A. Yes.

Q. Now, I have a better copy of this, but it looks -- but I represent to you that the break in the line says site review of LAR and submit to NRC. And it shows a beginning point of March 31, 2009, and an ending point of June 30th, 2009. Will you accept that?

A. Yes, I can.

Q. Okay. And the site review that's referenced here is an engineering review by Progress personnel, isn't that correct?

A. Primarily. It would also include other personnel that are affected, but principally an engineering review. There would be other groups that did reviews.

Q. Okay. But this does not reference or refer to an expert panel, does it?

A. This is a Level I schedule. It's not going to have that detail in it.

Q. Okay. And in the next page, 37, there are some confidential numbers on this page.

A. I just might note, just to that point, this project has probably had easily a dozen different assessments performed by outside experts, inside experts, audit services, including the audit service department issue you mentioned earlier. None of those are on this schedule. You wouldn't have those kind of assessments on the schedule.

Q. Okay. Well, on that point, this schedule does -- it contemplates a three-month review of the draft that you would receive from AREVA, and then submittal to the NRC, correct?

A. Yes, it did.

Q. I mean, there is no contemplation here that there would be any kind of extended review of AREVA's work product, right, beyond the three-month review internally?

A. Yes. This schedule shows a three-month review. Recognize it was written before we had the lessons learned of Point Beach and the other submittals that were on-going with the NRC.

Q. Okay. And I could ask you to do this and look at each page of this document, but there was no presentation to management here that references the expert panel, is there?

A. There is no -- I can go through it. Give me just a few seconds.

A couple of things I note when reviewing this. First of all, yes, on Page 48 it talks about extensively using industry experience. That may have referred to the use of outside industry experts with regard to their view of the LAR. Additionally, if you look at Page 68 under EPU concerns, it talks about EC quality improvement actions and oversight of nonstationed personnel strategy and implementation. It is possible when those bullets were discussed, they discussed oversight plans for AREVA work which may or may not have included the expert panel. That's two points.

And the third point is I'm very aware at this point of the project that the oversight and assessment activities for the extended power uprate, which this was a much -- this presentation was not just for the LAR; it was for the entire project, that in the plans for the project were a large number of different assessments. It may be audits of accounting, it might be looking at project controls, it might be implementation steps. None of those assessments are mentioned in this presentation. It doesn't mean they weren't planned for. This presentation just didn't cover the self-assessment activities when they discussed it with management. But I am aware, and it's an easy record to find, any number of different assessments that are very similar in nature to the expert panel.

Q. And speaking of Page 48 here, this references the May 19th, 2008, meeting with NRC.

A. Yes.

Q. And that's a meeting that we have had extensive conversations --

A. Yes, and a meeting I was at.

Q. And you were there. And the slide that has the schedule on it, that was shown, that was part of the presentation to the NRC, wasn't it?

A. Which one?

Q. Well, the one that we talked about earlier that --

A. It may very well have been. They may have re-used that slide on --

Q. And you did not tell the NRC that you were going to have an expert panel review?

A. I don't believe we did.

Q. Okay. This presentation also shows management the licensing strategy that you intended to -- at some point prior to this time frame, you intended to pursue with respect to your LAR, does it not?

A. It does talk through a number of the issues we discussed last year and some specific licensing activities. And let me see if I can remind you of what we're talking about here. For example, in Pages 51 and 52, I see that it's talking about some very specific choke points with regards to the plant's ability to mitigate transients after the increase in power has been achieved.

These issues have to be addressed in the licensing application, and what the company was doing back in May was looking for any opportunities where we might need to submit licensing actions that would have to be -- the specific purpose of that meeting was to search out with the NRC to explore the options we were considering to determine if there were any, what you would call a link submittal, which is some portion of the license that might accept a method of doing an analysis or a specific action scenario. It would have to be approved prior to the NRC accepting the EPU submittal itself.

In other words, they want to approve this one piece of the license that you're going to use as a basis for your extended power uprate license. The NRC has gotten a new policy -- it was a relatively new policy at this time that those approvals would have to be achieved before the actual extended power uprate license would be accepted for review. And so these are cases where we were exploring what the right strategy to deal with these issues were with regard to this particular aspect of the way the NRC was licensing.

Q. But in this presentation there were several issues that you thought that you would be submitting, for lack of a better term, smaller LARs?

A. I would say that there were three or four items that we had identified that might require it, depending on which choice or method we chose to pursue. And we used this meeting to flesh out what the right option would be, how receptive they were to those link submittals, or if they needed to be link submittals, or if we thought we could use a different process.

And I have slept a couple of times since we had this meeting, but if my memory serves me correct, in some cases we took a different approach. One example would be boron precipitation. It's a phenomenon that has to be addressed post accident, and rather than applying for the use of a manual action going forward under extended power uprate that we already had a license for, we chose to modify the plant so that that manual action was no longer required.

In other cases we identified where those licensing activities would not be required because they could be performed under another process like the 50.59 process. And we discussed those with the NRC, and we came to agreement.

Q. Okay. At the time you -- at the time you met with the NRC, and apparently even in June of 2008, your strategy was still to pursue license amendment requests for several of the solutions, and only analyze one of the solutions under CFR 50.59, isn't that true?

A. Actually, I believe we only identified a single submittal that would be required in addition to the EPU submittal. At that point that was the rod ejection, and we did apply for and have received that license application. So it wasn't several; it was only one.

Q. Okay. But in this deck or these slides you reference, basically, a contingent LAR that you would submit, correct?

A. Yes. And in this case the discussion would have been around, for this presentation, would have been around, you know, should we come to the conclusion, working with the NRC, that that link submittal would be required and that would be when it would be submitted. So we were still in the process of making those evaluations and determinations.

Q. Okay. Fair enough.

A. But you are asking me what happened, and what happened is we only had to submit one.

Q. Right. But at the time your strategy was to submit several?

A. I'm lost in the timeline. We started with -- we started with not knowing how many we would have to submit going to the NRC and finding out. Working through and identifying which strategies would require a license amendment request in addition to the extended power uprate one and which ones did not, and then as we distilled down, we went from three to one. I don't know when we went from three to one. And we ended up with only one. So I'm not sure of the time line on top of each other with regard to when this presentation was made.

MR. REHWINKEL: Madam Chairman, I would like to ask for another exhibit to be identified for cross-examination. It would be 195.

CHAIRMAN ARGENZIANO: That's correct.

MR. REHWINKEL: And this is license request -- it actually should say License Amendment Request, Appendix E.

CHAIRMAN ARGENZIANO: Did you say Appendix B?

MR. REHWINKEL: E, as in Edward. And this entire document is confidential.

CHAIRMAN ARGENZIANO: Okay.

(Exhibit 195 marked for identification.)

THE WITNESS: It's probably worth noting that this document we were just looking at was only a month after we met with the NRC. So we were in the process of determining how we were going to deal with that feedback.

BY MR. REHWINKEL:

Q. That's fair enough. I understand that.

The purpose of my question was to identify essentially that you were -- your strategy was somewhat in flux in the sense that it was evolving based on your discussions with the NRC, is that fair?

A. That is very fair.

Q. Okay. Now, what I have passed out is a document I believe you are familiar with, is that correct? This is a draft of a summary of the LAR, at least as you had contemplated it before June 7th, 2010?

A. Yes. And I'm not sure of the exact date of this draft, because this is a draft document, and we need to understand that it is a draft document. In fact, I believe it has comments, word processing comments in the margins where a reviewer has added comments sometime after March and prior to, I'd say, July of this year, based on the information that is in it. So it's a draft document that was in existence or a status of a section of the LAR in that time frame.

Q. But it's fair to say that this document, absent the digital instrumentation -- is that a good terminology to use?

A. That's a good terminology. The application of the new regulation with regard to our digital instrument requirements.

Q. Okay. Aside from that, this document fairly represents the licensing strategy that Progress would pursue absent the digital instrumentation issue that has recently arisen, is that fair?

A. That's fair.

Q. Okay. And with the addition -- and what this document shows is that putting aside the rod ejection analysis, which you had already submitted a LAR for, and you have now received your license amendment related to that analysis?

A. That's correct.

Q. This document shows that you would pursue your LAR based on doing internally, within Progress, 50.59 analyses for all of the engineering solutions that would allow you to get to the thermal output that would support your amended license output, is that fair?

A. Well, let me -- I think I know your question, let me see if I can answer it correctly. Our strategy, and it is indicated in this summary in a number of places, is to be able to install the equipment under 50.59. Now, that what means is -- it's 50.59, or 10 CFR 50.59. That section of the regulation describes how a licensee may modify the plant without prior approval of the NRC. It provides the guardrails, so to speak. So long as we are inside those guardrails, we're allowed to make changes to the plant.

It's the process if we have got a new valve because they don't make the old valve, it's how we analyze installing that new valve is okay without prior NRC approval. So, in this case, a lot of the modifications required can be installed without prior NRC approval. That's our strategy. It's not the strategy everyone takes, but most have taken that strategy. And so, in effect, if I want to install a pump that has a higher capacity than the old pump, the NRC doesn't have a problem with that, and doesn't expect me to ask their permission ahead of time.

If later I want to take advantage of that new higher capacity to increase reactor power, then the NRC says, well, wait a minute, you're going to increase reactor power now. In order to do that, you need a license amendment. So our strategy has been to install the equipment required to support the basis for the NRC's approval without -- so that equipment can be installed without their approval. But it provides the function which gives the NRC the basis for approval of our increased reactor power.

Q. And, basically, the NRC expects that your 50.59 analysis would support that you can operate at the increased level safely?

A. No, and that's the fine point. The NRC would expect that my 50.59 analysis would say I could operate at the existing power level with that equipment installed. Okay. So the example I gave you is a good one. Well, we can actually use an example from the document.

In one case it says we intend to install a cross-tie system on our low pressure injection system. It's how we will mitigate a need for power uprate. The NRC is more than happy for me to install that system now at existing power levels, because it only supports the current licensed condition. Okay. So there's no problem with me installing it now, but I can't increase reactor power yet. That additional equipment adds additional margin that the NRC had not perceived as a need at the existing power level. So I can install it and operate the plant at existing power level without their prior approval.

Prior to increasing power, however, I would have to get their permission to take advantage of that equipment and analysis space. They would be required to review that analysis in order for them to say, okay, now that you have installed it, I can increase reactor power. In fact, it speaks to a great deal to your questions earlier about how much engineering work is required to submit the license application. This is a great example. They are going to want to see that you have designed and you are on the track to install equipment that has that true capability. They will review that capability, and once they see you have it, they will say, okay, now you can increase reactor power. That is just one element, but that is kind of a slice of how this works.

Q. And your license amendment request will explain to their satisfaction, if they approve it, that you can operate that reactor at the higher level with the engineering solutions that you have installed?

A. That's correct. The best way to describe it -- I'll give you an example. It is very complicated, because it is more than change in the plant required. But let's say that there was only one change. This one LPI cross-tie was the only change required in order for the NRC to say, okay, now you have changed the plant so that it can operate at a higher power level.

What we would do, and our strategy has been all along, to design that modification in a manner and license it in a manner such that it could be installed under the existing license without amendment. And once it is -- and as it is being installed, go to the NRC and say we are going to install a system which meets, in this case, a LPI cross-tie. It has a very specific specification, ability to respond to a transient, and as such, once that is installed, I should be able to increase reactor power, and I'm going to ask you permission, NEC, to increase reactor power.

So that's what is going on. Now, it's not just that one system; it's a number of different changes that were required, but that would be one example.

Q. So if I was looking at this document, which is -- what did we call this, 195, the third page of this is E-3. And since this entire document is confidential, I'm not going to read this, but I would leave it to you to read it if you feel like you can publicly state it. At the very top of that page there is a sentence. The first -- actually, the first two sentences. This in a nutshell is your strategy --

A. Yes.

Q. -- for supporting the license amendment request, ignoring for the sake of argument the digital instrumentation issue, is that correct?

A. Yes. I believe the sentence you're referring to starts, "CR-3 intends"?

Q. Well, actually, the one before that.

A. Yes. "These modifications improve plant margins at existing power levels." This particular sentence I would not characterize as confidential.

Q. But the next one.

A. "CR-3 intends to implement these modifications under 10 CFR 50.59, thus the installation of these modifications does not require prior NRC approval via this license amendment request."

Q. Okay. Now I think you said earlier in response to a question a couple of questions ago that some have pursued this particular approach to supporting a license amendment request, but some have not, is that correct?

A. I'm only aware of one plant that has not. I would say that that one plant's initial submission of a license amendment request was rejected by the NRC.

Q. And who was that?

A. I would rather not say.

Q. Okay.

A. I do know who it was. It's Point Beach.

Q. Okay. And is it your testimony that this approach is the -- would not find any -- let me ask it this way.

Is it your testimony that the approach that is embodied on this Appendix E3 would not cause any concern by the NRC with respect to your LAR under the circumstances of the type of uprate that you are planning at Crystal River 3?

A. No. And my basis for that is that by looking at virtually every power uprate that has been installed in the United States, virtually every one was -- the components were installed at least, or some of the components were installed under 50.59, and then the power increase was achieved after the license was in place.

Q. So you would agree, would you not, that the relative power increase that you propose under the LAR that you intend to submit is significant relative to other extended power uprate submissions that the NRC has received, would you not?

A. I'm sorry, I didn't really understand your question. I got turned around there.

Q. Would you agree that the CR-3 extended power uprate is a relatively large percentage increase?

A. It's a good uprate. It's not unusual. Just looking at the list of other uprates, there have been a large number between 15 and 20 percent, maybe 10 or 12 that have been approved.

Q. Now, what was Ginna, were they about 17 percent?

A. Ginna was 16.8 percent.

Q. But Ginna had also undergone in the '80s an uprate in the 18 percent range, had they not?

A. Give me one moment. I am only aware of one Ginna. There may have been two. I'm only aware of one.

Q. Would you agree -- I think Dr. Jacobs -- do you have Dr. Jacobs' testimony with you?

A. No, but I'll be happy to refer to it.

Q. Well, he has an exhibit that lists the uprates. Would you agree with that?

A. Yes, he does, and I'm familiar with the exhibit. To be honest, I'm surprised I don't see Ginna on one of my lists here.

Q. Okay. Well, if I could ask you to look at Page 4 of 4 of Dr. Jacobs' Exhibit 3.

A. Certainly.

Q. There is a footnote under the schedule.

A. Yes. This is why I do not list it in my list. Give me just a second. I feel better now.

What this is a note to, this is a -- this exhibit from Dr. Jacobs' testimony is actually a printout of a page from the NRC, and it lists all the increases in power of nuclear facilities in the United States. What it's referring to is capacity recapture power uprates are not included in this table, and then it lists Ginna of an uprate of 17 percent in '84, which I believe is the 16.8. Let me look at the date here. No, this is -- they did an additional 16.8 percent in 2006. So what happened in '84 at Ginna makes -- this makes a lot of sense to me.

Capacity recapture power uprates are a little different. I believe what this is referring to and why it's not in the table is that this -- I would like to verify, but I believe what we are seeing here is this was an increase in power that did not require a license amendment because the original license accommodated the higher power level, yet for some other reason Ginna chose not to operate at that higher power level.

And it may have been when they originally built the plant they got a power level to operate at a higher power level than they were able to achieve with the equipment they had installed. But as far as the NRC was concerned they could operate at the higher power level, and that is typically what this is referring to.

Q. Okay.

COMMISSIONER SKOP: Mr. Rehwinkel?

MR. REHWINKEL: Yes.

COMMISSIONER SKOP: Just for planning purposes, do you know how long you have on your cross remaining?

MR. REHWINKEL: I have probably another hour at least.

COMMISSIONER SKOP: Okay. Please feel free to continue.

MR. REHWINKEL: Okay. Is it the Commission's intention to go to a certain point tonight?

COMMISSIONER SKOP: I believe the Chairman indicated her preference was to adjourn at 5:30 this evening.

MR. REHWINKEL: Okay.

COMMISSIONER SKOP: So that's -- feel free to continue. What I'm most impressed with, though, is your ability to get opposing counsel to mark up your documents for you.

MR. REHWINKEL: Well, I do appreciate the fact that they have done this, because it accommodates the Commission, as well. I appreciate it.

COMMISSIONER SKOP: Just wait until you get the bill for billable hours. (Laughter.)

BY MR. REHWINKEL:

Q. Mr. Franke, we talked a little bit about the expert panel debrief.

A. Yes, sir.

Q. But before we get to that, isn't it true that in 2006 when Progress Energy set out to implement the extended power uprate that you thought that the process would be cheaper and less complex than it has turned out to be?

A. The licensing application process?

Q. Yes.

A. I believe that's true, yes. I believe when we started in 2006, we believed that the Ginna model would be sufficient and that the depth of information required by the NRC would be a lot less rigorous than subsequent NRC licensing activities proved to be. And as a result, we had to add time, we had to add cost, and I would also say that we changed our philosophy with regard to when the appropriate time to submit the license application was. We wanted to make sure that we took advantage of the lessons learned of previous license applications in ours, so that when we submitted we had the highest chance of receipt successfully by the NRC.

Q. You would agree that you thought the overall project would be easier in a relative sense, correct?

A. I think we believed that the license application would require less rigor. Easy is not a term I would apply or try to compare, you know, whether something was easier or not easier. It's just a matter of work. It's all work. It's good work to be in.

Q. But you thought that it would be cheaper, correct?

A. We thought that the licensing application piece would be cheaper. We thought the overall project, as we talked earlier when we referred to TOR-7, that the entire project would be more expensive. So the project has gotten a little bit cheaper overall, and the licensing piece of it has gotten a little more complicated.

Q. Absent the transmission piece of it, you thought it would be much cheaper, correct?

A. Well, if I want to take that one point out, yes, you are correct. We thought that the plant piece would be cheaper, we thought the transmission piece would be more expensive, and we were a little wrong on both accounts. But when you sum it all up at the end, it's about the same price.

Q. Okay. And over the time of the project the NRC's expectations have evolved, isn't that correct?

A. Absolutely.

Q. With respect to what they want to see in a license amendment request?

A. Yes. They continue to revise their process. A great example is this digital licensing. You know, the NRC -- ironically, we had just licensed the digital instrument we were intending to use, relicensed it for a related -- an unrelated application back in 2003. And now when we looked back in 2009 at the standards that have evolved there, those standards have moved, and we no longer could use that same basis that they had approved in 2003 for 2009.

Q. In your testimony, you attached a copy of a contract with AREVA, and that is attached as Exhibit

JF-7, is that correct?

A. This is rebuttal. Yes, sir. I do have that.

Q. And that contract represents your expectation that AREVA would deliver to you, at the time, at the milestone that was assumed in the contract a draft LAR of sufficient quality to be accepted by the NRC, isn't that true?

A. In this case, what this was a contract to perform was to generate a license application as defined at the time that the contract was written. It did not accommodate any changes in scope that might be required to meet a moving standard.

Q. Okay. But your expectation from AREVA was that they deliver a draft; at the time they delivered it that would meet your expectations of acceptance by the NRC, correct?

A. No. I would say that our contract with AREVA was to deliver a draft in accordance with the scope and format that we had communicated to them that it was expected.

Q. Okay. Well, you didn't enter into this contract with the dollar amounts that are assumed in the contract with the expectation that they would give you a product that you would not be able to submit to the NRC, were you? Did you?

A. The intention of this contract -- I would love to able to get a vendor to sign a contract that says I want you to meet whatever future standard might be placed on the requirements of this work. That is not the way it works.

This was a contract written with AREVA to a specific scope and expectation. That's how these contracts are written. I can't get a contract from AREVA that says I want you to meet the requirements the NRC may have in three years.

Q. And you expected AREVA to provide this work product on the time frame that you expected or you contracted for it, correct?

A. That's correct.

Q. And that time frame was in the spring of 2009, correct?

A. I'd have to review the contract, but I know our intention was to have this original scope and format license amendment request draft provided to us by the summer of 2009.

Q. And you also expected AREVA to have the requisite expertise to produce the work product that you contracted for, correct?

A. That's a difficult question to answer, Mr. Rehwinkel. AREVA didn't have a staff full of engineers that had ever produced an extended power uprate license before. However, they were the only staff that had the proprietary knowledge required to generate that information. So I would say that I would expect them to use their engineering staff they had to produce a document that met a format and a scope that we had defined.

It would have been unreasonable for me to expect and impossible for me -- or for AREVA to produce a staff that was experienced at delivering an extended power uprate license because they don't exist on the planet. They didn't at that time, anyway.

Q. Okay. December 11, 2006, when management approved or formally authorized the CR-3 EPU, is it your testimony then that you were aware that AREVA had some lack of expertise or experience with respect to producing an acceptable draft LAR?

A. I would say that we knew that the engineers that would be producing this document may not have had extensive EPU experience. Here is the issue. There are two kinds of experiences that are required to produce this document and one set of proprietary information. So when you go to contract with whomever you are going to contract, first you have to get the people that are technically qualified on the equipment and the basic design of the reactor plant. Okay. Then it would be nice to have some people that not only had that knowledge, also had done this kind of licensing design reviews previously. The analysis itself isn't that much -- isn't that special, it is similar to analysis that had originally been performed when the plants were originally licensed, as well as in subsequent engineering work that AREVA had performed for other similar licensing activities.

But, you know, in a perfect world there would be that group of folks that have that all wrapped up into one. It just doesn't exist. It will -- when we are finally done with this project, AREVA will have a staff that has done it.

It is probably worthwhile to note in this contract, if you look at Page -- the page numbers using the docketed page numbers, 6 of 91, the contract accounts for time and material billing as part of the scope, part of the rules under which this contract would be enforced.

Q. But you would agree that on December 11, 2006, there was some awareness on Progress' part that AREVA might need some extra supervision and contract management by Progress, correct?

A. That's correct. In fact, that was one of the reasons we chose to, and subsequently as we worked through this process, we laid out a plan to have that expert panel review as a self-assessment process.

Q. You didn't communicate that to AREVA, though, did you?

A. I have no idea if we did or not. I know that they knew we would be using a self-evaluation process. Whether they knew it would be these particular people looking at it, I don't know.

Q. And isn't it true that Progress had what you consider the requisite engineering skills to oversee AREVA and their performance of what you contracted for?

A. I think Progress in conjunction with some outside expertise, we had the ability to go back and look at whether they were producing a quality product or not.

Q. Now, isn't it true that when you got the work product from AREVA and you saw the results, you, Progress' management, saw the results that the expert panel identified, that you were disappointed in the work product that you received from AREVA?

A. Yes, we were very disappointed. Absolutely. The expert panel review, as we were receiving the first big cache of the sections of the license amendment, demonstrated that AREVA had done a very poor job, and that some of the submittals from AREVA -- and, in fact, some from my own inexperienced staff had not provided the details required, nor met the original scope of the original contract. As such, we went back with AREVA. We sat down. You know, we were very disappointed in our oversight to date. Very happy we had the expert panel. We used that expert panel to define where those deficiencies were, do a good job of understanding it, use our nuclear condition report system to do an investigation of what caused the problems, and put in place corrective action so it would not happen again. And I can assure you I didn't pay AREVA an extra dime to meet that extra scope.

MR. REHWINKEL: Madam Chairman, I would like to ask for two exhibits to be identified for the record for cross-examination.

THE WITNESS: And I just misspoke. I didn't pay an extra dime for the original scope.

CHAIRMAN ARGENZIANO: They will be 196 and 197, and if you can give a brief description.

MR. REHWINKEL: Okay. 196 would be CR-3, EPU Expert Panel.

CHAIRMAN ARGENZIANO: At the mike so that our court reporter can hear you, can properly hear you.

MR. REHWINKEL: 196, that would be Expert

Panel would be a good short title.

CHAIRMAN ARGENZIANO: Okay.

MR. REHWINKEL: And 197 would be Adverse Condition Investigation.

CHAIRMAN ARGENZIANO: Thank you.

(Exhibits 196 and 197 marked for identification.)

MR. REHWINKEL: And I should say that 196 is a document entitled CR-3 EPU Expert Panel Management Debrief, July 14, 2009. While 197 has a cover sheet with an action request, and then an Attachment 3, which is the adverse condition investigation form. There are some documents in between that are just -- I can provide them, but I think they are mostly kind of recordkeeping, housekeeping documents.

THE WITNESS: They are.

BY MR. REHWINKEL:

Q. You are familiar with both of these documents, are you not?

A. Yes, sir, I am.

Q. Okay.

MR. REHWINKEL: And, Madam Chairman, I did not have a chance to provide these to the company for confidentiality determinations. I don't know if we could huddle for just a couple of minutes with the company to talk about them.

CHAIRMAN ARGENZIANO: Okay. Let's do that and take a few minutes.

(Off the record.)

CHAIRMAN ARGENZIANO: While we have a few minutes, if everybody listens up, just when you have confidential information, you might want to have them highlighted so that we don't have to do this. And not -- no real big problem, just for the future reference so that we can keep moving smoothly in case there is other information. We plan to close today at -- you know, recess today at 5:30. Tomorrow we'll probably stay later.

(Off the record.)

MR. BURNETT: Madam Chairman, may I be recognized?

CHAIRMAN ARGENZIANO: Where are you? Yes. Please, go right ahead.

MR. BURNETT: Good evening. Madam Chairman, I'm not quite sure how these documents got classified as confidential, no yellow highlighting, and they seem to have them on top, but these can be spoken about freely in the public. Neither one of these documents are confidential.

CHAIRMAN ARGENZIANO: So both are not confidential?

MR. BURNETT: Yes, ma'am. Any content can spoken of freely.

CHAIRMAN ARGENZIANO: Okay. Thank you.

MR. BURNETT: Thank you for the time to review.

CHAIRMAN ARGENZIANO: Appreciate that. Thank you.

MR. BURNETT: Thank you.

MR. REHWINKEL: Thank you.

BY MR. REHWINKEL:

Q. Mr. Franke, are you familiar with Exhibits 196 and 197? I may have already asked you that.

A. Yes, I am.

Q. Now, 196 is a slide presentation that I assume was given by the expert panel to management on July 14th, 2009, is that correct?

A. That's correct.

Q. Okay. And the first page after the title page, Page 2 just lists the team members of the panel, correct?

A. That's correct.

Q. And the first two, Bryan Miller and Mark Turkal, T-U-R-K-A-L, they are Progress employees, correct?

A. They are Progress employees, yes, sir.

Q. Okay. And they were employees that had the requisite experience to be able to evaluate critically the submittal by AREVA, correct?

A. Yes, in conjunction with the team. They have some experience with extended power uprates. They work for Progress Energy Carolinas. But, yes, they work for Progress Energy.

Q. Okay. Now, the third page of this document gives -- tells the scope of the review, and isn't it true that what the panel looked at was a single draft copy of the AREVA work product?

A. Yes, as well as some of the work that was performed by my own people. It's probably worth noting, by the way, as you talk about the team members experience, Bryan Miller and Mark Turkal were experienced with previous EPUs. So their experience was more historical in nature.

Greg Ellis, however, is a gentleman that's very active in ongoing licensing activities, and as such was probably the one member that brought forward the more recent experiences with extended power uprates. Bryan and Mark had not worked on power uprates for many years. If you look at the dates of the Waterford and Brunswick extended power uprates, they were years before.

Q. Okay. Now, the third page. Okay. It shows the scope, and then the purpose was to assess the LAR, that's the draft licensing report, correct?

A. That's correct.

Q. To see whether it would meet NRC acceptance review and provide sufficient detail for the NRC to independently conclude acceptability of the project for purposes of a license amendment, is that right?

A. That is correct.

Q. And the document also lists the review standards, the RS-001, compare it to the Ginna EPU submittal, and the Ginna responses to the RAI, the Request for Additional Information, as well as the NRC's safety evaluation for the Ginna EPU and the Point Beach EPU submittal?

A. That's correct.

Q. Okay. Now, what the fourth page shows are the specific deficiencies that the panel found. They note that there was a cut and paste job in the Ginna submittal that even included, I guess, Ginna specifics that had no applicability to CR-3?

A. Yes. What the panel review identified is that some of the work by AREVA had essentially been electronic clip and paste. They had taken the Ginna submittal, and for those more generic sections, not the facility-specific sections that required AREVA engineering, but some of the more -- a lot of the LAR is technical in nature, a lot of it is just a lot of language, and in those sections that might have been just kind of generic language, which encompasses the purpose of an extended power uprate and that sort of thing, that we actually found the word Ginna still in the sections.

Q. In the third bullet point there it says that it appears that the RAIs and the NRC safety evaluation for the Ginna EPU -- I said safety, it says SE, but that's what that means, right?

A. Yes. SE is Safety Evaluation. That is when you submit a license application request, the NRC's technical detailed response is called a Safety Evaluation or a Safety Evaluation Report.

Q. Okay. It says that they were not considered or addressed in this draft license report, is that correct?

A. Absolutely. And we can go through the whole presentation if you'd like. The point you are making is very valid, and it was a disappointment by us. It was clear AREVA had not done the job we had contracted them for.

Q. Well, didn't the NRC -- didn't your discussion on May 19th, 2008, almost, I guess, a year earlier, the NRC specifically told Progress to pattern the LAR after the most recent PWR efforts, Ginna, including consideration of RAIs?

A. Absolutely.

Q. Okay. So was that communicated to AREVA?

A. Yes, it was.

Q. Okay.

A. So what happened here is we found using the expert panel they had made mistakes. We did a thorough scrub. We were embarrassed by the results. We went back to AREVA, sat them down, had a lot of strong conversations. Disappointment is probably a weak description of my personal opinion of what we were at, and we went back and explained to them that they were going to go fix it and fix it on their dime, and that's what they did.

Q. Exhibit 196. Well, first of all, after this debrief occurred, I expect that you very quickly -- if we look on Exhibit 196, near the top of the page, it looks like this action request was originated the very next day.

A. Yes, sir.

Q. Okay. And there's a summary of the independent review that I assume the Progress team did once they received this debrief, is that correct? Is that what this summary shows on the first page of Exhibit 197?

A. If you are talking about -- it says -- at the top it says Action Request 00345243.

Q. Yes.

A. And then it's in the table format where it says description.

Q. Yes.

A. That's a description of the problem. That's kind of a problem statement that is written at the time the nuclear condition report is initiated.

Q. Okay. The next page, which is -- it says Attachment 3, Sheet 1 of 2, adverse condition investigation form. This is the guts of what the Progress -- well, actually, tell me who did this adverse condition investigation form?

A. We actually used a team. The specific investigator was a gentleman named Bryan McCabe (phonetic). His name is on the top of the second page in the handout, but it is the first page of the investigation report form.

Q. Now, who does he work for?

A. He works for our corporate -- he works in our corporate office. Bryan is a -- he's a senior regulatory affairs specialist. He has a couple of licensing engineers working for him. He's -- he's one of our licensing experts in the company.

Q. Okay. So he has the expertise to do this review that is in this -- that's attached to Exhibit 197?

A. Yes.

Q. Okay. And you agree with the findings, the investigation summary as well as the apparent cause that is shown on Attachment 3, is that true?

A. I agree, yes, absolutely.

Q. Okay. Now, we could go through all of this, but it's fairly self-explanatory. The investigation summary essentially shows that the work product of AREVA was of poor quality, correct?

A. Yes. The work product of AREVA was of poor quality.

Q. Okay.

A. For the reasons identified in this investigation.

Q. Now, this document -- neither this document nor the presentation that is contained in Exhibit 196 make any reference to evolving NRC -- increasing industry standards associated with NRC licensing activities, do they?

A. I'm not sure if it does. This was investigating the overall poor quality, and it was looking at, including those things like the Ginna clip and paste errors and that, essentially, it did not meet the original scope and content of the investigation. So I would say that this investigation was looking more at why the contract did not meet its initial scope and sequence.

Q. This investigation, meaning what is in 197?

A. That is correct.

Q. Okay. But, again, the report of the expert panel makes no mention of increasing industry standards associated with NRC licensing activities, does it? In fact, doesn't the expert panel reference the guidance the NRC gave you about the RAIs for Ginna a year ago?

A. I think you's mixing some apples and oranges here. This was not a root cause of why AREVA did not meet their contractual requirements, okay. This was a root cause as to why we were not in a position to have the licensing application approved.

There is a misconception here. The problem was we weren't ready to submit the license application. Okay. And this investigation did not look at things like contractual -- meeting the contract or costs associated with what would be required to meet the contract. It was answering the question why aren't you able to submit your license application, or why isn't it further enough developed right now in order to submit your license application. What you are trying to apply it to is why didn't AREVA meet their contract. That is two completely different things. So this isn't -- nowhere in that problem statement does it say why didn't AREVA meet its contract.

Q. Which problem statement is that?

A. The problem statement that was on that first page you just referred to.

Q. But the root cause analysis is that this was -- that AREVA did a sloppy job?

A. No, it isn't. It doesn't say AREVA anywhere in here. Well, it say AREVA and NGG activities. But the adverse condition is not why didn't AREVA meet its contract. You have got to be very careful when you ask a specific question to one of these guys that's trained on root cause, they are going to answer that question. And the question here was why there was not a high quality EPU LAR with sufficient content and quality to pass the NRC acceptance review. I'm quoting from the first page of the investigation report form.

So it is answering the question why aren't you ready to submit your license application. It isn't answering the question why didn't AREVA do its job. That was a conversation I had with AREVA management.

Q. Okay. But under the apparent cause LAR quality issues heading at the bottom of the first page of the adverse condition investigation form, F3A, I assume that's a category?

A. Yes, that is a code we use to -- we do a hundred of these a year, maybe not to this level, but we do a large number of investigations. We try to categorize them into categories as to the reasons why we made a mistake at the plant.

Q. Okay. And it says management follow-up or monitoring activities did not identify problems. Do you agree with that? Not only that it says it, but that is what happened?

A. Yes.

Q. Okay. Now, do you remember when we started off cross-examination awhile back, I asked you about the dollars that were included in your Direct Testimony related to project management. Do you remember that, and licensing activities, correct?

A. Yes, sir.

Q. Those dollars would be covering activities that would oversee this contract as well as the Progress

Energy employees that were associated with this draft LAR activity, correct?

A. I think what this investigation identified and what the expert panel identified is that the level of engagement -- and you can read that a lot of ways. How I read that is we were not spending sufficient time or sufficient resources to oversee the AREVA work early enough. So when we start turning it into dollars, and some of this is semantics, and I want to be careful here. I'm aware that this particular document was subject to audit by staff.

When you send an accountant to go review something and he sees that there is improper financial management, they will write a sentence that says, you know, management monitoring was not sufficient. This root cause was saying why wasn't the licensing work done correctly, and what it's identifying is very clear to me, that we were not spending sufficient resources on this licensing application and we needed to spend more money on it, not less in oversight.

Q. Well, the intention of Progress was not to get this type of work product or get it in a way that delayed -- well, first of all, it was not your intention to get the work product that the debrief -- the expert panel --

A. No, we expected it to be at a higher quality at that stage.

Q. And you didn't expect the six-month delay that the rewrite caused in the preparation of the draft LAR, correct?

A. We did not expect the six-month delay. But I will tell you today that one of the -- and it is not in this investigation because it wasn't part of the problem. But one of the fallouts of this expert panel review was a better understanding of what the NRC -- of the right way to continue to engage with the NRC.

And let me make sure that this is clear. Prior to this expert panel review, I think we were still kind of stuck on the idea that the Ginna submittal was the right model, okay. Greg Ellis and the others that came forward in this expert panel, they took a step back and looked at other licensing activities. They said wait a minute, this standard from Ginna is no longer the right standard, and the NRC expectations are moving.

One of the lessons of this expert panel was while it did delay the licensing application, when we took a step back and looked at our strategy going forward, we recognized that early submittal is not necessarily good, because early might mean you don't have the lesson of a license application that is on going. So, yes, it did cause a six-month delay, but I will tell you since then I have made conscious decisions not to submit earlier because I might not be supplying a license application that is up to the latest standards and it might get rejected. Other utilities have made that mistake. It's not my intention to make that mistake.

Q. You would agree, though, that had the expert panel said that this was a good draft LAR you would have submitted it, wouldn't you?

A. I may have submitted it, and from what I now understand of the changing NRC standards, it likely would have been rejected.

Q. You didn't know that at the time?

A. The expert panel explained that to me.

Q. They explained that to you in this document?

A. Yes, they did.

Q. Is there a mention in here that had the --

A. Yes.

Q. -- quality of this been right that it would have still failed?

A. Well, let's be careful. I'm going back. I'm doing the same thing I accused you of earlier. I am mixing the contract with the changing standards. If you look at the expert panel, and I don't know the number of the exhibit, the exhibit numbers --

Q. This is 196.

A. 196 is absent from my copy. But the presentation by the expert panel, it talks about the license report quality on one page. And that speaks to a large degree, and there is no page numbers here, but --

Q. Lower left.

A. Lower left. That speaks more to the contract, of meeting the original contract. But if you look at the next page, Page 5, okay, most of this detail talks about scope beyond what that original visionary scope of 2006/2007 was when the contract was signed with AREVA. That the NRC has now gone further, and Ginna standards that they discuss as not meeting on Page 4 is no longer the standard required by the NRC, and that you are going to have to go farther and longer. Okay. You are going to have to look at Point Beach, you are going to have look at the other submittals that were ongoing. Why Monticello was rejected, okay, and you are going to have to incorporate those lessons learned. So this is really more a reflection of scope increase beyond that original contract scope.

This isn't an assessment of the contract. It's an assessment of the activity. That contract, what we found out from the expert panel was not everything required in order to achieve the application we needed, and so we had to go beyond that original contract scope.

Q. Well, doesn't on Page 5, the item that reads based on the LAR review, aren't they -- it says the technical work has not progressed far enough to support the submittal. Absent this information, the LAR cannot be submitted to the NRC.

A. And that is exactly what I'm talking about. Here is where the expert panel is telling me that the detail requirements of the licensed application, the rigor that is explained and demonstrated in that application is a higher standard than what we are providing. And that's the lessons of those license applications that I just talked about, Point Beach, Monticello, and other applications that have occurred.

Q. But it says that the work has not progressed. It doesn't say what they did falls short of what the NRC requires, does it?

A. That's the next page.

Q. But the items --

A. Look on Page 6, at the top Page 6. Reading, it says the current EPU LAR will not pass NRC acceptance review.

Q. But that's because of the quality of it, isn't it?

A. Read the next word. The next sentence is extensive technical work is necessary to complete the large submittal. This is talking about that technical rigor and depth and detail that we were talking about.

Q. But on Page 5 it says based on the LAR review, technical work has not progressed far enough to support the submittal. If you go back to Page 2 of the document, the panel notes that -- doesn't the panel discuss that the draft wasn't even complete?

A. Yes.

Q. Okay. So what the panel was saying is that they didn't get the work done on time?

A. That's correct.

Q. Okay. And Page 5 says that based on the LAR review, technical work has not progressed. That is part of that problem that they didn't fulfill the milestone that the contract expected, which is to give you a complete draft, right?

A. Let me detail it out for you here. AREVA did not meet our schedule. They did not meet the original scope and content of their original contract. We held them to task with that regard, and we had them rewrite and meet that original contract at their expense.

Additionally, the expert panel recognized that the contract was not sufficient. Now, they didn't go in and review the contract. That wasn't their purview. Their purview was to say is this application going to meet the newest standards. And what that they identified was, wait a minute, you know -- and this was really something subsequent to the expert panel, because they weren't asked to look at the contract. It was that the depth of detail, and that is what is being talked about in Page 5, that the scope of work identified in that original contract would never meet today's standards for the NRC, despite the fact that they had indicated to us back in -- was it 2007, May of 2007, that the Ginna submittal was the right model. Well, in 2009 the expert panel told us that is not the right model anymore. You have got to go well beyond what Ginna submitted if you are going to be successful today.

Q. The items that are listed on Page 5 --

CHAIRMAN ARGENZIANO: I'm sorry, did you have a question?

COMMISSIONER SKOP: Just before we conclude today I have a brief question, not for the witness.

CHAIRMAN ARGENZIANO: Mr. Rehwinkel, on your line of questioning continue, and then when you -- when we take a break from that point that you are trying to get to --

MR. REHWINKEL: Okay. I will just ask one more question, and then --

CHAIRMAN ARGENZIANO: Fine.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q. The items on Page 5 that start with EC development for advanced ADV, Atmospheric Dump Valves, right?

A. Yes.

Q. Okay. Those items there, they represent incomplete analysis in the draft, not changes in the NRC's regulations, correct?

A. Let me try to use this example to try to drive the point home, okay. The Ginna submittal, for example, might have said that we are going to use atmospheric dump valves -- and this is an example, Ginna didn't use this strategy. But let me see if I can relate it in simple terms so that it's clear. I'm doing a bad job, clearly.

For example, with regard to this bullet, the level of detail explained by the Ginna submittal may say we're going to use atmospheric dump valves in order to depressurize the reactor to meet this small break LOCA, okay. And it might go into some cursory analysis that says that that should be sufficient, okay. What this bullet is saying is that you actually -- the EC development, EC is actually the Engineering Change package, and this goes back to what we have been talking about for a year now. What this expert panel is telling me is that not only do you have to tell the NRC that you are going to use ADVs, you have got to perform the engineering change. You have got to go into the details of which valve you are going to use; what size it's going to be, what is the blowdown that this valve can accomplish, in other words what pressure it can accomplish in what time frame; how does that line up against the timeline of a small break LOCA. Show me your reactor model that demonstrates that that blowdown will be sufficient to depressurize the reactor, and your high pressure injection pumps can provide enough flow into the reactor so that the design is adequate. That's what I am talking about.

In Ginna they might have said ADS valves. EDC development -- EC development means you need that engineering change written and designed and developed. And that's what I'm talking about here. The Ginna depth of detail got -- the depth of detail required for this specific example was now much larger than it had been before with the Ginna.

Now, they weren't comparing to Ginna. What they were comparing to is what is the new requirements, what is the present requirement.

Q. I guess my question still is what's the meaning of the phrase has not progressed far enough? That connotes that there was a target that the AREVA folks should have known about and just did not get the work done.

A. I'm still not communicating well. This expert panel never looked at the contract. So to imply that they made a conclusion relative to a contractual requirement is impossible. They were comparing the license application to the NRC standards. They didn't know what was in the contract. So this expert panel was not saying that AREVA didn't meet a contractual requirement? They never read the contract. They were reading with what's today's standard for the licensed application, and they said you're not meeting it.

Q. My question wasn't as to the contract, it was to the -- that AREVA, from what the expert panel is saying in this document here, is AREVA had some expectations about the completeness of their work that they did not meet.

A. I don't think AREVA had that expectation. That is where the root cause comes in. I don't think AREVA had the expertise to know the depth of detail required. The expert panel came in and said to the point of that apparent cause where we talked about inexperienced engineers, is that they did not have, as we discussed before, they had never submitted one, and, oh, by the way, they hadn't submitted one lately. And with the lack of that knowledge, they didn't know where the bar was. The contract was written to a lower bar than what is required today, so here is what we did. We took a step back. We said you are going to meet the contract requirements and you're going to meet it on your dime.

Now, we are both recognize that that scope is much higher, that bar requires a much more extensive technical review. In fact, now it includes the EC development for some of these modifications, and now we are going to have to go forth and develop those ECs, develop that technical rigor prior to submittal. All of this led to the conclusion that I'm not going to submit this EPU LAR too early. I want to make sure I understand the standards at the time that I submit it, and I'm going to have the depth of detail so that it isn't kicked back like the other licensees had to face.

MR. REHWINKEL: Well, I can stop at this point. I have some other questions about this adverse condition.

CHAIRMAN ARGENZIANO: Okay. Why don't we do this. Commissioner Skop had a question, and then I think we are going to go into recess until tomorrow morning.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

My question is not to the witness, it's for planning purposes, so if this is the appropriate time.

CHAIRMAN ARGENZIANO: Okay. Then let's do this. I think Commissioner Graham had a question to the witness or to Mr. Rehwinkel.

Commissioner Graham.

COMMISSIONER GRAHAM: Thank you through the Chair. Actually, I think I'm just trying to understand.

THE WITNESS: Yes, sir.

COMMISSIONER GRAHAM: The shortfall here was the contract you initially had with AREVA didn't hold them -- you said it was to a lower standard. So had you sat down with the expert panel prior to the writing of the contract with AREVA, maybe you would have known where that standard should have been and then drafted a contract off of that.

THE WITNESS: In a perfect world, yes. Unfortunately, those lessons were actually learned -- in fact, Mr. Rehwinkel didn't point it out; I could have.

On an earlier document we talked about Point Beach. Point Beach is where we learned a lot of this, and that was an application that was received in 2009. So, unfortunately, at the time this contract was written, Ginna was the right standard, but while the work was progressing that standard moved.

COMMISSIONER GRAHAM: But with AREVA, when they first came back to you, they didn't hit the standard that you originally contracted with, which was --

THE WITNESS: No, they did not.

COMMISSIONER GRAHAM: -- already a low standard, but they didn't hit that standard that you contracted. You held their feet to the fire. They brought the work up to the standard that you had contracted, and then the expert panel told you you still don't want to go forward, but that it's because you didn't go far enough.

THE WITNESS: Yes, that's correct. They said that that -- once again, they didn't review the contract. We wrote the contract based on the scope of work of Ginna. As they were working through that contract, as I explained, the standard moved.

COMMISSIONER GRAHAM: Yes.

THE WITNESS: And it moved fast and far.

There is a number of EPU LAR submittals that had to be withdrawn in this time frame because the NRC standards were moving fast. So when they delivered the product, you're right, I wasn't happy. And we were disappointed both in AREVA and our own performance to allow them to deliver something that didn't meet the contract. We held their feet to the fire. They performed the work back under their dime, and they were able to meet that original standard.

Now, since we learned, mind you, in that time frame from the expert panel, and we started looking even better, even more closely with the ongoing licensing activities, we said, okay, we're going to have to add some money to this contract, add some expenses associated with the LAR, because this standard is higher than that original contract recognized. And that's what we have been doing since.

COMMISSIONER GRAHAM: So there is no fault here, it's just a moving target.

THE WITNESS: I don't want to dissuade. I was not happy that they didn't meet that contract. So there was fault there.

COMMISSIONER GRAHAM: I mean, but they fixed that.

THE WITNESS: They fixed that, and they fixed it on their dime. I was a little disappointed my team didn't notice it earlier. We had the expert panel in place to be able to catch this kind of mistake, but I was disappointed, quite frankly, that it got to that point. But from a cost standpoint, it didn't cause any increased cost. It was just a matter of being a little upset at my vendor and upset at my own staff for allowing that to happen.

COMMISSIONER GRAHAM: Okay. I just wanted to make sure I understood it.

THE WITNESS: Yes, sir.

CHAIRMAN ARGENZIANO: Thank you.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair. And, again, this is just related to planning purposes, so if it is the appropriate time.

CHAIRMAN ARGENZIANO: It's the appropriate time.

COMMISSIONER SKOP: Okay. And relating to planning purposes related to the FPL case, which, again, we are going to take up at some future point in time when Progress' case in chief is over, I'd like to have the opportunity, based on further reflection, to ask Mr. Olivera some constructive questions on behalf of his company. And I know Mr. Olivera is not listed on the order of witnesses, and I don't expect that he would sponsor testimony. However, in light of recent events, I do have some questions that I think it would be constructive on behalf of the Commission for me to ask.

And I would perhaps ask our staff to inquire with FPL's counsel, I don't know if they are still here, whether Mr. Olivera would perhaps make himself available. And if not, we do have subpoena power under Florida Statutes if we need to go there. But I just would look to our staff to address that concern.

MS. HELTON: I see Ms. Cano is in the audience. If I were Ms. Cano, I probably would not want to address this question right now without consulting with her management. So why don't we approach it this way, Madam Chairman, if it is okay with you and Commissioner Skop. Why don't we talk to Power and Light and see what their response is and then go from there. I would rather not say anything further than that right now.

CHAIRMAN ARGENZIANO: Thank you.

Commissioner Skop.

COMMISSIONER SKOP: And thank you, Madam Chair. And, again, I think that, again, staff is able to have conversations that I can't have directly, but if he is available, I do have a few questions that I would like to have the opportunity to ask if that would be amenable. And if not, I guess we can look at it from a different perspective. But I think that addresses my concerns. And, again, I do have some follow-up questions for Mr. Franke tomorrow when the intervenors are done.

CHAIRMAN ARGENZIANO: Okay. We can do that. Let's do this, let's make sure that staff secures all the confidential --

COMMISSIONER EDGAR: Can I ask a question?

CHAIRMAN ARGENZIANO: Sure.

COMMISSIONER EDGAR: I just want to make sure I understand. Commissioner Skop, are you telling us that you have questions during the FPL portion of this proceeding, not the Progress portion, that none of the witnesses that are on the list to appear before us would be able to address?

COMMISSIONER SKOP: Based on the list of witnesses, it's my belief that they would not be able to answer the questions on behalf of the company in the manner in which I would expect to get answers.

COMMISSIONER EDGAR: And I am just trying, again, for planning purposes trying to think through the next few days, and it is --

COMMISSIONER SKOP: Well, I think, just to be clear, again, the length of today's proceeding and the number of witnesses, it's going to be fluid. What my intent was is to provide as much advance notice as possible, given recent events have made things, you know, kind of fluid. But, again, if our staff could pursue that, you know, certainly I'd like the opportunity to ask those questions. And, you know, as far that goes I think that is my perspective to ask them. Again, he has not sponsored testimony nor do I expect him to sponsor testimony. But on behalf of his company, I do have some questions that I'd like to hear from the -- from him.

COMMISSIONER EDGAR: And I'm not sure what you mean by recent events, but I will leave it at that. I don't know what that means, but that's okay.

COMMISSIONER SKOP: At this point I don't think I need to explain it to you. I think that at the appropriate time, if he appears, I'll ask my questions and it will be self-evident.

COMMISSIONER EDGAR: I wasn't finished with my question. But my question was are we still -- we are still looking at this week for that request, and just again for --

COMMISSIONER SKOP: I don't know when Progress will finish its case in chief. Again, Mr. Rehwinkel indicated he still probably has probably about 30 more minutes of cross-examination on this witness. We have other intervenors and we have other witnesses. But just for planning purposes, if our staff could inquire. And, again, staff may want to look at some additional hearing dates, given the way that this is moving along.

You know, we had four days scheduled. Hopefully, we will get into the FPL portion before the end of those four days, but I can't predict the future. But, you know, this is contingency planning. I think it is important that we start looking at additional days. I know we have September 1, 2, and 3 open, and the 8th and 9th. So we might want to take a look at that.

CHAIRMAN ARGENZIANO: Okay. Questions?

MS. HELTON: Madam Chairman.

COMMISSIONER EDGAR: Actually, I would have, actually, liked to have not been interrupted while I was trying to pose a question, but I do think I got the answer that I was looking for. So, thank you.

CHAIRMAN ARGENZIANO: Okay.

Ms. Helton.

MS. HELTON: Thank you.

On reflection, it may help in our discussions with Florida Power and Light if we had some idea of what the subject matter was for the questions from

Commissioner Skop.

CHAIRMAN ARGENZIANO: I don't know. I can't --

Commissioner Skop.

MS. HELTON: And maybe I can add a little bit more to that that might help Commissioner Skop, too.

COMMISSIONER SKOP: Very well. Please feel free to do so.

MS. HELTON: As I understand our ability to call witnesses, Power and Light may have the opportunity to suggest someone who they think might be more appropriate to answer the questions or who might be at a different level who could still answer the questions. And so I think it would help, with respect to our conversations with them, to have an understanding of what the questions are, the scope of the questions, or the subject matter of the questions, so that they feel like there's a valid reason to have the president of the company come to the hearing when he had not planned to do so.

CHAIRMAN ARGENZIANO: Commissioner Skop.

COMMISSIONER SKOP: Again, having given it sufficient thought and looking at the list of witnesses, again, I think it is a fair question to ask. And I'm not so sure that I like the manner in which it has been styled, but I think it suffices to say I have asked for Mr. Olivera for a very specific reason. He is President and Chief Executive Officer of Florida Power and Light. And, again, I think that when we get to their case there is some constructive things that the company has done; there are also some things that they need to answer for, and my constructive questions posed to Mr. Olivera would be concerning the accuracy and the timeliness of information that his company provides to this Commission.

CHAIRMAN ARGENZIANO: I think it has been stated what the Commissioner would like to do, and we will take it from there. I guess staff can -- I guess we will find out tomorrow morning.

MS. HELTON: Yes, ma'am. Thank you very much.

CHAIRMAN ARGENZIANO: Thank you.

And what I would like to do is make sure that we secure the confidential packets that we have. I think that 197 and 196 were not confidential, so we don't have to worry about those two.

And with that we will recess until 9:30 tomorrow morning, and be prepared to probably stay late tomorrow. Later.

Commissioner Graham, I'm sorry.

COMMISSIONER GRAHAM: Madam Chair, I guess since we are on the conversation of Florida Power and Light, are we going to start off with the questions that staff had and then go from there? Because we may find out that there is enough answers after the questions that staff had to handle most of the things -- other questions that people may have. So I think that's a great starting point. If not all the questions are -- if not all of the questions are satisfied at that point, we can move forward. But I think that may be a good place to start.

CHAIRMAN ARGENZIANO: Commissioner Skop.

COMMISSIONER SKOP: Thank you. And thank you, Commissioner Graham.

Again, staff has their questions. Again, I have some of my own. Again, FPL has sponsored witnesses, I have technical questions related to the testimony. I have questions related to issues, live issues before the Commission.

CHAIRMAN ARGENZIANO: Commissioner Skop, may I?

COMMISSIONER SKOP: Yes, ma'am.

CHAIRMAN ARGENZIANO: Go ahead, finish up. I didn't mean to cut you off.

COMMISSIONER SKOP: No. And, again, I just want to be free to ask the questions. Again, what

Public Counsel and some of the intervenors have requested is nothing more than tantamount to being a blanket deferral of all issues until a future point in time, and I'll get into that specifically when we discuss the motion that comes before the Commission.

It is not going to be a pleasant discussion. I mean, I have sufficient reasons as to why I should be able to ask my questions and why the Commission has its obligation to conduct a thorough review. I think Mr. Rehwinkel made that case for me this morning or this afternoon when he specifically stated the provisions that require the Commission to conduct a proceeding and to look at the prudency and project management controls on an annual basis.

So, again, I'm saving that discussion until the appropriate time. I didn't want to get bogged down in that to the detriment of Progress this morning, but I do have questions. And I hope I'll have the opportunity --

CHAIRMAN ARGENZIANO: Well, I think we will wait and see what happens tomorrow. And if there are further questions, everyone should be entitled to have answers to their questions.

And with that, let's recess until 9:30 tomorrow morning. Thank you.

(The hearing adjourned at 5:50 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

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

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

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

DATED THIS 1st day of September, 2010.

Jane Faurot

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