BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 130009-EI
Submitted for filing: March 1, 2013

DIRECT TESTIMONY
OF JON FRANKE

ON BEHALF OF
PROGRESS ENERGY FLORIDA, INC.

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IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA, INC.

FPSC DOCKET NO. 130009-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 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") 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 I am responsible for the safe operation of the Crystal River 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.

Q. Did your role or responsibilities change with respect to the CR3 Uprate project as a result of the July 2, 2012 merger between Progress Energy, Inc. and Duke Energy Corporation?

A. No. My role and title remained the same and my responsibilities with respect to the Crystal River Unit 3 Nuclear Power Plant ("CR3") and the Extended Power Uprate ("EPU") project ("CR3 Uprate") did not change as a result of the merger between Progress Energy, Inc. and Duke Energy Corporation ("Duke Energy").

Q. Has the merger impacted the CR3 Uprate project organizational structure?

A. Yes. In the fall of 2012, as a result of the merger integration process, the project management organizational structure for the CR3 Uprate project was adjusted and the Manager, Major Projects – EPU reports to the General Manager, Fleet and Stand Alone Projects, a new position in the combined company. In addition, the CR3 Uprate Engineering Manager was a direct report to the Nuclear Engineering Department and is now a direct report to the Manager, Major Projects – EPU. These changes did not affect my responsibilities. I remain the CR3 Uprate project sponsor.

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 in Annapolis, MD. I have a graduate degree in the same field from the University of Maryland and 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 United States 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 & Light and was with that company through the formation of Progress Energy and the subsequent merger with Duke 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. I was promoted to my current position in April 2009.

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 costs incurred in 2012 for the CR3 Uprate project. I will explain that these costs were prudently incurred for the CR3 Uprate project. I will also address PEF's 2012 project management, contracting, and cost oversight policies and procedures for the CR3 Uprate project and explain why they are reasonable and prudent.

On February 5, 2013, Duke Energy announced that the Duke Energy Board of Directors decided to retire and decommission the CR3 nuclear power plant. As a result of this decision, the CR3 Uprate project was cancelled. The prudence of the decision to retire rather than repair CR3 will be addressed in

Phase 2 of Docket No. 100437-EI, accordingly, I will not address the decision to retire CR3 in my testimony. My direct testimony addresses the prudence of the Company's CR3 Uprate project expenditures in 2012, prior to the Duke Energy Board decision to retire CR3, consistent with the provisions of the nuclear cost recovery clause rule. In my May 1, 2013 direct testimony, I will address the cancellation of the CR3 Uprate project as a result of the Board's decision to retire CR3, and the actual and estimated, and projected costs necessary to cancel and wind-down 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), Project Management and Fleet Operating Procedures applicable to the CR3 Uprate project revised in 2012; and
- Exhibit No. ___ (JF-2), Project Management and Fleet Operating Procedures applicable to the CR3 Uprate project new in 2012.

In addition, I am sponsoring Schedules T-6A, T-6B, T-7, T-7A and T-7B and Appendix D and co-sponsoring the cost portions of Schedules T-4, T-4A, and T-6 of the Nuclear Filing Requirements ("NFRs") for the 2012 CR3 Uprate project costs, which are included as part of Exhibit No. __(TGF-2) to Thomas G. Foster's testimony. Schedule T-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the 2012 period. Schedule T-4A reflects CCRC recoverable O&M expenditure variance explanations for the 2012 period. Schedule T-6.3 reflects the construction expenditures for the project by category. Schedule T-6A.3 reflects descriptions of the major cost categories of the expenditures and Schedule T-6B.3 reflect explanations for the significant variances between these expenditures and previously filed estimates for 2012. Schedule T-7 is a list of the contracts executed in excess of $1.0 million for 2012. Schedule T-7A reflects details pertaining to the contracts executed in excess of $1.0 million for 2012. Schedule T-7B reflects contracts executed in excess of $250,000, but less than $1.0 million for 2012.

All of these exhibits, schedules, and appendices are true and accurate.

Q. Please summarize your testimony.

A. In this direct testimony, I am supporting the Company's request for a prudence determination and approval for recovery of the actual costs it incurred in 2012 for the CR3 Uprate project. PEF incurred CR3 Uprate project costs in 2012 in preparation for Phase 3, the EPU phase of the project, consistent with the Company's plan in 2011 and 2012 to repair the CR3 containment building, complete the CR3 Uprate project, and return CR3 to commercial service at the end of the existing CR3 outage. The Company primarily incurred EPU costs in 2012 for (1) EPU long lead equipment ("LLE") milestone payments contractually committed to prior to 2012; (2) licensing and engineering costs associated with responding to Requests for Additional Information ("RAIs") for the NRC's review of the Company's EPU License Amendment Request ("LAR"); and (3) engineering analyses for the engineering change ("EC") packages for the EPU Phase work, with project management costs associated with this work. PEF continued to take appropriate steps to minimize CR3 Uprate project spend in 2012 to ensure that only those costs necessary for completion of the CR3 Uprate project in the current, extended CR3 outage were incurred in 2012, consistent with the project management plan implemented by the Company in 2011 and reviewed by the Commission in the nuclear cost recovery clause docket last year. Accordingly, PEF's 2012 CR3 Uprate project costs are reasonable and prudent and PEF requests that the Commission grant PEF's request for recovery of these costs pursuant to the nuclear cost recovery statute and rule.

III. ACTUAL COSTS INCURRED IN 2012 FOR THE CR3 UPRATE PROJECT.

Q. Can you please explain the status of the CR3 Uprate project in 2012?

A. Yes. PEF continued the CR3 Uprate project in 2012 consistent with the determination PEF made in 2011 that the reasonable course of action was to preserve the option of completing the CR3 Uprate project during the current, extended CR3 outage, if the Company determined to repair CR3 upon completion of the Company's evaluation of the decision to repair or retire CR3. At that time, the Company planned to repair CR3 and complete the CR3 Uprate project. The Company continued required EPU work for this plan in 2012, while deferring EPU work activities and costs that were not necessary in 2012 to successfully complete this plan. As a result, only those activities were performed and those costs incurred in 2012 that were necessary to complete the EPU project during the current, extended CR3 outage in the event the Company decided to repair CR3.

Q. What costs did PEF incur for the CR3 Uprate project in 2012?

A. PEF incurred construction costs for the CR3 Uprate project in 2012. The total capital expenditures for 2012, gross of joint owner billing and exclusive of carrying cost, were $44.3 million. This is $7.2 million less than PEF estimated it would spend in 2012 for the CR3 Uprate project. This reduction in expenditures from what PEF estimated that it was going to spend in 2012 is the result of PEF's efforts to efficiently manage the CR3 Uprate project and to push out milestones to later years as necessary to ensure only those costs were incurred that were necessary to complete the EPU work if PEF decided to repair CR3. These costs were incurred in the categories of: (1) license application, (2) project management, (3) permitting, (4) on-site construction facilities, and (5) power block engineering, procurement and related construction. Schedule T-6 in Exhibit No. ___ (TGF-2) to Mr. Foster's testimony provides further details about these costs.

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

A. Actual 2012 License Application costs were about $2.9 million. The Company's EPU LAR was submitted to the NRC on June 15, 2011 and the NRC accepted the EPU LAR for review on November 21, 2011. In the NRC's Acceptance Review letter, the NRC indicated it might defer portions of its review of the EPU LAR pending a more final CR3 repair schedule. Later, however, the NRC initiated the Technical Review phase of the LAR process and, in practice, did not defer any portion of the NRC review. As a result, the Company had to incur costs in 2012 for the work required for the NRC Technical Review.

In 2012, the Company prepared and submitted responses to 176 RAIs to support the NRC's Technical Review of the EPU LAR. In 2012, the NRC made substantial progress toward completing its review of the EPU LAR, in fact, many NRC technical branches completed their reviews. The EPU LAR was on target for receipt in time for plant start-up based on the Company's schedule to repair CR3 and complete the EPU work during the current, extended CR3 outage. The License Application work and associated costs were necessary in 2012 for the NRC Technical Review of the EPU LAR and to preserve the option to complete the EPU phase in the current, extended CR3 outage.

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

A. Actual CR3 Uprate project management costs in 2012 were approximately $3.3 million. The Company's Project Management costs included the following project management activities for the CR3 Uprate project in 2012:

(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; and

(5) overall management of CR3 Uprate licensing and EPU LAR work.

Each activity was conducted under the Company's project management and cost oversight policies and procedures consistent with industry best practices for a major project like the CR3 Uprate project. The Project Management work and associated costs were necessary for the EPU work and to preserve the option to complete the EPU phase in the current, extended CR3 outage.

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

A. The Company incurred $10,709 for permitting costs for the CR3 Uprate project in 2012. These costs were incurred for evaluations by Golder Associates associated with limited permitting activities for the Point of Discharge ("POD") Cooling Tower. The limited permitting work and associated costs were necessary to preserve the option to complete the EPU phase in the current, extended CR3 outage.

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

A. The Company incurred $35,242 for On-Site Construction Facilities costs for the CR3 Uprate project in 2012. These costs were incurred for storage for components and tools. These limited on-site construction facilities costs were necessary for the project and to preserve the option to complete the EPU phase in the current, extended CR3 outage.

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 approximately $38.1 million for Power Block Engineering, Procurement, and related construction cost items for the CR3 Uprate Project in 2012.

The Company incurred EPU costs for contract milestone payments for fabrication of LLE items that were contractually committed for the project prior to 2012. PEF received and stored several LLE items for the CR3 Uprate project in 2012. Manufacturing of these LLE items was completed in accordance with the terms of material fabrication and procurement contracts entered into prior to 2012. PEF placed the following LLE items in storage at CR3 in preparation for Phase 3 installation: Condensate Pump Motors; High Pressure Turbine Rotor; Low Pressure Turbine Rotors and Casings; In-Core Detector Assemblies; Low Pressure Injection Cross Tie Valves; and Feedwater Valves.

PEF also incurred costs in 2012 for engineering work to support and respond to NRC RAIs for the EPU LAR application and to develop the EC packages for the EPU Phase 3 work. Only engineering work necessary to preserve the option to complete the EPU work during the current, extended CR3 outage was performed in 2012. By May 2012, the EPU phase EC packages were approximately 70 percent complete; EPU phase EC packages are now approximately 75 percent complete. PEF effectively managed the EPU phase engineering work through proper prioritization for completion of vendor contracted ECs and owner review and acceptance of LLE. For example, PEF managed its time and materials engineering scope changes and labor resources to respond to high priority NRC information requests and pushed out less critical path EC work in order to minimize costs without jeopardizing the implementation of the EPU during the extended outage.

PEF appropriately minimized these EPU costs in 2012 where possible. All of the 2012 Power Block Engineering, Procurement, and related construction costs were necessary for the implementation of the CR3 Uprate work in the current, extended CR3 outage, and they were prudently incurred in 2012.

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

A. Overall, PEF incurred net expenses of ($48,019) of Non-Power Block Engineering costs related to the EPU POD lay-down yard. There were non-power block engineering costs in 2012 incurred to meet environmental compliance regulations and to maintain the integrity of the stored equipment. Offsetting these costs was an accounting entry to reverse an expense accrual booked in 2011 that was no longer necessary as a result of closing a contract.

Q. How did actual capital expenditures for January 2012 through December 2012 compare to PEF's actual/estimated costs for 2012 for the CR3 Uprate Project?

A. PEF's actual capital expenditures for the CR3 Uprate project in 2012 were lower than PEF's actual/estimated costs for 2012 by $7.2 million. This variance is based on PEF's actual expenditures for 2012 compared to the Actual/Estimated ("AE") Schedules attached to Mr. Foster's April 30, 2012 testimony, which reflected actual/estimated 2012 CR3 Uprate costs, prior to the Commission's approval of the Company's Motion to defer Commission review of the 2012 CR3 Uprate construction expenditures and associated carrying costs to this docket. As a result of the Commission's decision to grant that Motion, I understand Mr. Foster filed revised NFR AE schedules with the Commission to reflect that deferral.

This variance is the result of the Company's efficient project management of the CR3 Uprate project work to ensure that the only costs incurred were necessary to complete the project during the current, extended CR3 outage if the Company decided to repair CR3. I will explain the reasons for the major (more than $1.0 million) variances below:

Power Block Engineering, Procurement and related construction costs:

Power Block Engineering, Procurement and related construction cost capital expenditures booked on Schedule T-6.3 were $38.1 million for 2012. The estimate for these costs in 2012 was $45.4 million, resulting in a favorable variance of ($7.3 million). The majority of the variance is attributed to deferral of contract payments, control and reduction of engineering work scope, and lower warehouse inventory expenses than projected as a result of deferring EPU work and costs beyond 2012.

This variance, again, demonstrates the results of the Company's efforts to minimize CR3 Uprate project costs in 2012 while still preserving the Company's ability to complete the project in the current, extended CR3 outage if the Company decided to repair CR3.

Q. **Were there any other major variances in 2012 for license application, project management, permitting or on-site construction facility costs?**

A. No. As described on Schedule T-6B.3, the variances for these categories were all minor variances.

Q. **Did PEF incur O&M costs in 2012 for the CR3 Uprate project?**

A. Yes. PEF incurred necessary O&M costs to support the CR3 Uprate project work in 2012. These O&M costs are identified and included in Schedule T-4 in Exhibit No. ___ (TGF-2) to Mr. Foster's testimony.

Q. How did actual O&M expenditures for January 2012 through December 2012 compare with PEF's actual/estimated O&M expenditures for 2011?

A. Schedule T-4A, Line 15, on Exhibit No. ___ (TGF-2) to Mr. Foster's testimony shows that total O&M costs were $0.5 million or $65,356 more than estimated. Schedule T-4A shows the minor variances for the O&M costs categories. There were no major (more than $1 .0 million) O&M cost variances to report in 2012.

Q. Were PEF's 2012 CR3 Uprate project costs reasonably and prudently incurred?

A. Yes, they were. PEF incurred only those CR3 Uprate project costs in 2012 necessary to preserve the option to complete the EPU phase during the current, extended CR3 outage, if the Company decided to repair CR3. PEF implemented a project management plan to minimize project costs until the Company made the decision to repair or retire CR3. PEF diligently worked to minimize project costs consistent with that plan throughout 2012. As a result, in 2012 PEF was in position to proceed with the CR3 Uprate project work to implement the EPU phase during the current, extended CR3 outage if the Company decided to repair CR3, but the Company had not unnecessarily incurred costs to move forward with the project. All of PEF's 2012 CR3 Uprate project costs were reasonably and prudently incurred.

Q. Can you please explain how PEF minimized CR3 Uprate project costs in 2012?

A. Yes, I can. In 2012, PEF was proceeding with a CR3 Uprate project plan and schedule to complete the EPU work during the current, extended CR3 outage. PEF understood that completion of this work in accordance with this schedule depended on the Company deciding to repair CR3 after evaluating the decision to repair or retire CR3. As a result, the CR3 Uprate project plan in 2012 was designed to minimize project costs in 2012 while preserving the Company's ability to complete the EPU phase during the current, extended CR3 outage if the Company decided to repair CR3.

As part of the CR3 Uprate project plan in 2012, PEF evaluated the EPU phase work to identify what work was critical to proceed with to maintain a schedule to complete the EPU phase work during the current CR3 outage and what work was not on this critical path. Based on this evaluation, PEF slowed down and postponed work on the EPU phase in 2012 to minimize the CR3 Uprate project costs while preserving the Company's ability to complete the EPU work during the current CR3 outage and implement the power uprate. No EPU phase work was accelerated and mainly regular work hours were permitted on EPU work that PEF had determined needed to be done to maintain this CR3 Uprate project schedule.

PEF delayed the selection of a construction contractor for the EPU phase work from 2012 to the 2013 time frame. PEF individually evaluated each contract and change order for the EPU phase work before execution. For contracts or change orders below $100,000, the EPU phase project manager performed this evaluation; for contracts or change orders at or above $100,000, the project manager conducted this evaluation and made recommendations with respect to execution of the contract or change order that were reviewed by the manager of nuclear projects and senior management. No contract or change order at or above $100,000 for the EPU phase work was executed without senior management approval. That approval was not granted unless there was a demonstration that the work under the contract or change order was reasonable and necessary to preserve the Company's ability to complete the EPU work on the current CR3 Uprate project schedule.

This type of evaluation was conducted for each item of work for the EPU phase of the CR3 Uprate project. PEF, accordingly, continued payments on the critical path LLE items to implement the EPU phase in the current extended CR3 R16 re-fueling outage. LLE progress payments in 2012 reflect pre-existing contractual commitments. Deferral of these payments was not a viable option in 2012 without cancellation or suspension of contracts, which would result in penalties and an uncertain future regarding LLE contract renewals to meet the EPU phase work schedule if the decision was made to repair CR3. Accordingly, only those LLE contractual payments necessary for the EPU phase work for the project were incurred in 2012.

Q. During 2012, were other steps taken by the Company to minimize EPU phase work costs?

A. Yes. As 2012 progressed, PEF took several additional steps to ensure that only costs necessary to maintain the option of implementing the final phase of EPU during the extended CR3 outage were incurred. First, on a staffing level, the EPU staffing plan was limited to filling open positions only, and no additional staffing occurred for the project in 2012. In fact, during 2012, the Company reduced Project Support staffing for the CR3 Uprate project. Engineering resources also were reduced in 2012 as development of the EPU EC packages reached 75 percent complete. The Company also continued its practice of sending EPU personnel to provide additional outage support at other plants across the fleet to reduce staffing for the EPU phase work. In this way, the Company ensured the minimal workforce needs for the CR3 Uprate project in 2012.

PEF rigorously reviewed CR3 Uprate costs in 2012 to ensure that only those costs necessary for completion of the EPU work in the extended outage were incurred until a final decision to repair or retire CR3 was made. PEF acted reasonably and prudently in managing the CR3 Uprate project in 2012 to achieve this result. The costs the Company did incur in 2012 for the CR3 Uprate project, therefore, were reasonably and prudently incurred.

Q. Have the Company's efforts to minimize the CR3 uprate costs in 2012 actually resulted in the avoidance or deferral of costs to a later time period?

A. Yes. As I explained above, PEF's actual capital expenditures for the CR3 Uprate project in 2012 were lower than PEF's actual/estimated costs for 2012 by $7.2 million. This is the result of the Company's decision to postpone construction work for the CR3 Uprate project and to minimize staffing and other CR3 Uprate project costs, as I have described above, until management's final decision on whether to repair or retire CR3.

Q. Was the Company's decision in 2012 to continue with the CR3 Uprate project reasonable and prudent?

A. Yes. The Company had not yet completed the extensive analysis of the CR3 containment building repair decision necessary to decide to repair or retire CR3. That analysis was on-going in 2012, and it depended on continued technical design, engineering, and construction work to determine the scope of the repair work, the technical, engineering, construction, and licensing costs and risks, and the schedule for the repair, together with an economic evaluation of repairing or retiring CR3. During this period, the only options available to the Company for the CR3 Uprate project were cancelling the project, accelerating the project, or preserving the ability to complete the project during the current, extended CR3 outage if the decision was made to repair CR3. The Company reasonably and prudently chose to continue the CR3 Uprate project to preserve the ability to complete the EPU phase work if CR3 was repaired while minimizing the project costs until the decision to repair or retire CR3 was made.

IV. 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 this 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 project. In other words, the Company only included project costs that would not have been incurred but for the CR3 Uprate project.

V. PROJECT MANAGEMENT, CONTRACTING, AND COST OVERSIGHT.

Q. Were the CR3 Uprate Project Management, Contracting and Cost Control Oversight policies and procedures in 2012 substantially the same as the policies and procedures used prior to 2012?

A. Yes. The Company used substantially the same project management, contracting, and cost control oversight policies and procedures in 2012 that the Company used in prior years for the CR3 Uprate project. In fact, for the first six months of 2012, the EPU project management, contracting, and cost control oversight policies and procedures were exactly the same as the policies and procedures in effect in prior years for the project. On July 2, 2012, the merger between Progress Energy and Duke Energy was completed and the process to integrate the two companies commenced. This integration process is on-going, as the policies and procedures are fully integrated, and best practices employed in the new, combined company. In the meantime, the majority of the every-day project management and fleet policies and procedures have not changed substantially. The EPU project management team has remained the same as well. Some of the policy and procedure revisions incorporate Duke Energy governance practices or fleet best practices and lessons learned based on the integration process to date. Other policies and procedures were revised to reflect Duke Energy titles and organization structure. Exhibit No. ___(JF-1) to my direct testimony contains a list of the Project Management policies and procedures, as well as relevant Fleet and Plant operating procedures, that were revised during 2012 and the reason for the revision.

Through the merger integration process, some new project management, contracting, and cost control oversight policies and procedures were added in 2012 that apply to the CR3 Uprate project. Exhibit No. ___ (JF-2) to my direct testimony contains Project Management policies and procedures as well as relevant Fleet and Plant operating procedures that were newly created or new to and applicable to the CR3 Uprate project in 2012. These policies such as the Fleet Operating Model (PY-AD-ALL-0001), Fleet Standard Workday (AD-AD-ALL-0004), and Conduct of Nuclear Oversight (AD-NO-ALL-1000) procedures were made applicable to the CR3 Uprate project as a result of the merger. The Company is also in the process of transitioning to Duke Energy's project approval process. Duke Energy's Approval of Business Transactions policy ("ABT") and Project Funding Approval (BM-100) and Project Evaluation and Business Case Development (BM-500) superseded the Progress Energy Integrated Project Plan ("IPP") procedures. These procedures reflect what the integrated Company's approval process will be for the fleet on a going forward basis but did not impact the CR3 Uprate project in 2012.

Despite these minor revisions or new policies and procedures, for 2012 the Company's CR3 Uprate project management, contracting, and cost oversight control policies and procedures were essentially the same as the prior year CR3 Uprate project policies and procedures reviewed and approved as reasonable and prudent by this Commission. *See* Order No. PSC-09-0783-FOF-EI, issued Nov.

19, 2009; Order No. PSC-11-0547-FOF-EI, issued Nov. 23, 2011; and Order No. PSC-12-0650-FOF-EI, issued Dec. 11, 2012.

Q. Can you please provide an overview of the Company's CR3 Uprate project management and cost control oversight policies and procedures in 2012?

A. Yes. The Company uses several specific project management and cost oversight Nuclear Generation Group ("NGG") and Corporate procedures, as I describe in exhibit No. __(JF-1) to my direct testimony. In addition, other corporate tools are used to support the management of and cost control oversight for the CR3 Uprate. The Oracle Financial Systems and Business Objects reporting tools provide monthly corporate budget comparisons to actual cost information, as well as detailed transaction information. Key Performance Indicators ("KPIs") to monitor the status of the CR3 Uprate project are reviewed by the project team on a regular basis. Other examples include, EPU Level II Schedules and Action Items; EPU Look-Ahead Schedule; and Monthly Variance Reports. These tools were all used to prudently manage the CR3 Uprate project costs in 2012.

Q. How does the Company manage and control project costs for the CR3 Uprate project?

A. The Company has many control mechanisms in place to manage CR3 Uprate project costs. For example, the CR3 Uprate project management team conducts regular internal meetings to monitor the project schedule and its costs. The collective knowledge and experience of the project management team is used to address work scope, costs, and schedule performance through a continuous review of the project, including team roles and responsibilities, by creating and implementing lessons learned on an on-going basis, and through regular project management training. Project management regularly addresses equipment and material procurements under contracts, purchase orders, and invoices, and constantly monitors contracts with outside vendors. This includes regular meetings with outside vendors to discuss work scope and implementation, schedule, and costs.

Q. Does the Company verify that the 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 cost oversight controls are being implemented and are effective in practice. Quality Assurance ("QA") reviews and audits of external vendors are also conducted.

On December 6, 2012, the Audit Services Department issued the "Crystal River 3 (CR3) Financial Regulatory Compliance" audit. This audit included an examination of 2011 and 2012 capital and O&M charges related to CR3 for compliance with the 2012 Stipulation and Settlement Agreement. Other considerations included the NCRC and EPU filings. No specific audit observations or recommendations were identified.

On November 9, 2012, the internal audit department issued the "Crystal River 3 (CR3) Restart Program Management" audit. This audit included a follow up of the 2011 audit of the CR3 Program Management. The audit also included an assessment of the effectiveness of the oversight, governance, and site

Operational Readiness initiatives supporting the planned restart of CR3. Two moderate priority observations were identified that referenced the EPU including follow-up on enhancements recommended in a 2011 audit and 16R start-up plan effectiveness. All of the management action plans in response to these observations are complete or scheduled to be completed.

Several contractor and quality assurance evaluations were also performed in 2012 including audits and surveillance follow-up of Siemens for the Low Pressure Turbines; Flowserve for the Condensate Pump; Sulzer for the Feedwater Booster Pump; and SPX for the Feedwater Heaters 3A and 3B. The audits were generally satisfactory. Several open issues were identified; however, they were either corrected during the surveillance or are being corrected and will be confirmed closed in the surveillance process. None of these issues identified had any impact on 2012 CR3 Uprate costs.

In addition, Nuclear Procurement Issues Committee ("NUPIC") joint external audits were performed on two PEF suppliers in 2012. Scientech/Curtis Wright Flow Control Audit #23239 was performed March 12-16, 2012, which identified nine findings related to the vendor's quality program. The NUPIC audit team, lead by utility Xcel Energy, concluded that with the exception of the nine findings Scientech was adequately implementing their overall QA program and that the findings did not have a significant adverse affect on products or services provided to the nuclear utilities. As of July, 2012, a NUPIC surveillance team confirmed that the stated corrective actions had been implemented and the Findings and Audit were closed. Secondly, AREVA Audit #23171 was conducted from September 17-28, 2012, with lead utility Nebraska Public Power

District. This audit identified five findings to which AREVA responded and only two remain to be completed in 2013 related to necessary revisions to AREVA's QA manual and the creation of condition reports for any nonconformance identified. None of these issues had any impact on CR3 Uprate 2012 costs.

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 and now the combined company, Duke Energy, and the companies have independently or collectively vetted, enhanced, and revised them, as necessary, to reflect industry leading best project management and cost oversight policies, practices, and procedures in 2012. These collective policies and procedures are essentially the same policies and procedures that have been vetted in an annual project management audit in this docket and have been repeatedly approved as prudent by the Commission. We believe, therefore, that the CR3 Uprate project management, contracting, and cost control oversight policies and procedures are consistent with best practices for capital project management in the industry and continue to be reasonable and prudent.

Q. Does this conclude your testimony?

A. Yes, it does.

Procedure Number	Procedure Revision Number/Date	Procedure Title
ACT-SUBS-00335	Rev 8 (July 2012)	Progress Energy Project Governance Policy. Effective Legal Day 1 of the new Duke Energy, this procedure has been superseded by the new Duke Approval of Business Transactions (ABT) policy. During a transition period, this procedure will remain available as a reference document for Legacy Progress employees; however, the new ABT policy governs approval requirements.
ACT-SUBS-00261	Cancelled (July 2012)	Phased Project Evaluation and Authorization Process. The document has been cancelled from the Procedures and Forms Program effective Legal Day 1 of the Progress Energy – Duke Energy merger.
ACT-SUBS-00262	Cancelled (July 2012)	Economic Evaluation Methodology All Business Units. The document has been cancelled from the Procedures and Forms Program effective Legal Day 1 of the Progress Energy – Duke Energy merger.
ACT-SUBS-00271	Rev 8 (July 2012)	Progress Energy Business Analysis Package. Effective Legal Day 1 of the new Duke Energy, this procedure has been superseded by the new Duke Approval of Business Transactions (ABT) policy. During a transition period, this procedure will remain available as a reference document for Legacy Progress employees; however, the new ABT policy governs approval requirements.
ACT-SUBS-00278	Cancelled (July 2012)	Capitalization Policy. The document has been cancelled from the Procedures and Forms Program effective Legal Day 1 of the Progress Energy –Duke Energy merger.
ADM-SUBS-00080	Rev 8 (July 2012)	Major Projects – Integrated Project Plan (IPP). Effective Legal Day 1 of the new Duke Energy, this procedure has been superseded by the new Duke Approval of Business Transactions (ABT) policy. During a transition period, this procedure will remain available as a reference document for Legacy Progress employees; however, the new ABT policy governs approval requirements.
PJM-SUBS-00002	Rev 2 (May 2012)	Project Integration Management. No impact at this time from the Duke merger.
PJM-SUBS-00006	Rev 1 (June 2012)	Project Quality Management. No impact at this time from the Duke merger.

Procedure Number	Procedure Revision Number/Date	Procedure Title
PJM-NGGX-00001	Rev. 1 (June 2012)	Achieving Excellence in Nuclear Projects. No impact at this time from the Duke merger.
NGGM-IA-0047	Cancelled (October 2012)	Interface Agreement Between the Nuclear Generation Group and Corporate Development & Improvement Group Regarding NGG Support for the New Generation Programs and Projects Department. Corporate Development & Improvement Group relocated to a different department as a result of the Duke merger.
ADM-NGGC-0102	Rev 9 (October 2012)	Long Range Planning (LRP) and Project Review Group (PRG). This procedure impacted by the new Duke Approval of Business Transactions (ABT) policy.
ADM-NGGC-0104	Rev 42 (December 2012)	Work Implementation and Completion. No impact at this time from the Duke merger.
ADM-NGGC-0107	Rev 14 (June 2012)	Equipment Reliability Process Guideline. No impact at this time from the Duke merger.
ADM-NGGC-0110	Rev 8 (October 2012)	Oversight of Contractors, Shared Resources, Vendors and Technical Representatives (Supplemental Personnel). No impact at this time from the Duke merger.
ADM-NGGC-0113	Superseded (November 2012)	Superseded by new Duke procedure AD-AD-ALL-0004 Nuclear Generation Department Generation Planning and Communications.
ADM-NGGC-0116	Rev 6 (February 2012) Rev 7 (September 2012) Rev 8 (October 2012)	Nuclear Planning. No impact at this time from the Duke merger.
ADM-NGGC-0118	Cancelled (November 2012)	Fleet Health Process. Procedure was cancelled due to organizational and process changes related to the Duke/Progress merger.
ADM-NGGC-0119	Rev 2 (October 2012)	Nuclear Safety Culture Program. No impact at this time from the Duke merger.
ADM-NGGC-0204	Rev 7 (August 2012)	Work Management (WO Scheduling). No impact at this time from the Duke merger.
CAP-NGGC-0200	Rev 35 (June 2012)	Condition Identification and Screening Process. No impact at this time from the Duke merger.
CAP-NGGC-0201	Rev 18 (October 2012)	Self Assessment/Benchmark Programs. No impact at this time from the Duke merger.
CAP-NGGC-0202	Rev 21 (September 2012)	Operating Experience and Construction Experience Program. No impact at this time of the Duke merger on this procedure.

Procedure Number	Procedure Revision Number/Date	Procedure Title
CAP-NGGC-0205	Rev 16 (June 2012)	Condition Evaluation and Corrective Action Process. No impact at this time from the Duke merger.
CAP-NGGC-1000	Rev 8 (November 2012)	Conduct of Performance Improvement. Revised to reflect new Duke Fleet Procedure Hierarchy, New Fleet Standard Workday, Clarified acceptance of qualifications from Legacy Duke and Legacy Progress and changed management titles to reflect new Duke.
CAP-NGGC-1000	Rev 7 (June 2012)	Conduct of Performance Improvement. No impact at this time from the Duke merger.
EGR-NGGC-0005	Rev 33 (August 2012)	Engineering Change. Revised to reflect new Duke Engineering Manager titles.
EGR-NGGC-0006	Rev 11 (November 2012)	Vendor Manual Program. No impact at this time from the Duke merger.
EGR-NGGC-0006	Rev 10 (September 2012)	Vendor Manual Program. No impact at this time from the Duke merger.
EGR-NGGC-0008	Rev 13 (September 2012)	Engineering Programs. No impact at this time from the Duke merger.
EGR-NGGC-1010	Rev 1 (August 2012)	Conduct of Design Engineering. Changes to clarify the Design Authority as Nuclear Design Engineering or Nuclear Fuels Engineering, and add requirements to obtain Design Authority review for design developed by Nuclear Major Projects Engineering. Deleted Major Projects Design Engineering, Fleet Fire Protection and Metallurgical Services since these groups are no longer part of Design Engineering. Revised the Manager Nuclear Design Engineering Services, Supervisor NGG Configuration Management, Configuration Management Personnel and Manager Nuclear Fleet Design Engineering responsibilities.
HUM-NGGC-0001	Rev 11 (September 2012)	Human Performance Program. No impact at this time from the Duke merger.
HUM-NGGC-0001	Rev 10 (March 2012)	Human Performance Program. No impact at this time from the Duke merger.
HUM-NGGC-0002	Rev 4 (September 2012)	Observation Program. Revised definition for Paired Observation to align

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		with legacy Duke and newer INPO definition.
MNT-NGGC-0020	Rev 2 (September 2012)	Cranes and Hoists. No impact at this time from the Duke merger.
MNT-NGGC-0021	Rev 2 (September 2012)	Lifting and Rigging Practices and Equipment. No impact at this time from the Duke merger.
NOD-NGGC-0001	Superseded (November 2012)	Fleet Standard Workday. Superseded by new Duke procedure AD-AD-ALL-0004 Fleet Standard Workday.
OMA-NGGC-0001	Superseded (July 2012)	Nuclear Generation Group Generation Planning and Communication. Superseded by new Duke procedure AD-WC-ALL-0101 Nuclear Generation Department Generation Planning and Communications.
SAF-NGGC-2172	Rev 18 (November 2012)	Industrial Safety. No impact at this time from the Duke merger.
SAF-NGGC-2172	Rev 17 (November 2012)	Industrial Safety. No impact at this time from the Duke merger.
SAF-NGGC-2176	Rev 2 (November 2012)	Job Safety Analysis. No impact at this time from the Duke merger.
SEC-NGGC-2140	Rev 35 (August 2012)	Fitness for Duty Program. No impact at this time from the Duke merger.
SEC-NGGC-2140	Rev 34 (July 2012)	Fitness for Duty Program. No impact at this time from the Duke merger.
SEC-NGGC-2140	Rev 33 (January 2012)	Fitness for Duty Program. No impact at this time from the Duke merger.
TRN-NGGC-0002	Rev 2 (February 2012)	Performance Review and Remedial Training. No impact at this time from the Duke merger.
TRN-NGGC-0002	Rev 3 (August 2012)	Performance Review and Remedial Training. No impact at this time from the Duke merger.
TRN-NGGC-0002	Rev 4 (November 2012)	Performance Review and Remedial Training. No impact at this time from the Duke merger.
TRN-NGGC-1000	Rev 6 (May 2012)	Conduct of Training. No impact at this time from the Duke merger..
TRN-NGGC-1000	Rev 7 (October 2012)	Conduct of Training. Changed reference from ADM-NGGC-0113, "Performance Planning and Monitoring" to AD-BO-ALL-0002, "Performance Measures Program. Changed references to Training Manager Action Team to Training Manager Peer Group.

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PY-AD-ALL-0001	Rev 2 (November 2012)	Fleet Operating Model
ABT	Rev 1 (July 2012)	Approval of Business Transactions Policy
AD-AD-ALL-0001	Rev 0 (December 2012)	Corporate Functional Area Managers (CFAMS) and Peer Group Process
AD-AD-ALL-0004	Rev 0 (November 2012)	Fleet Standard Workday
AD-PI-ALL-0003	Rev 0 (December 2012)	Change Management
AD-NO-ALL-1000	Rev 0 (July 2012)	Conduct Of Nuclear Oversight
BM-100	Rev 5 (September 2012)	Project Funding Approval
BM-500	Rev 1 (October 2011)	Project Evaluation and Business Case Development