IN THE FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110009-EI

SOUTHERN ALLIANCE FOR CLEAN ENERGY,	)	
Appellant,	)	
v.	)	**NOTICE OF ADMINISTRATIVE APPEAL**
FLORIDA PUBLIC SERVICE COMMISSION, FLORIDA POWER AND LIGHT COMPANY, and PROGRESS ENERGY FLORIDA, INC.,	)	
Appellees.	)	

NOTICE IS GIVEN that the Southern Alliance for Clean Energy, Appellant, appeals to the Florida Supreme Court the Final Order of the Florida Public Service Commission ("Commission"), Order No. PSC-11-0547-FOF-EI, rendered the 23rd day of November, 2011.

The nature of the order appealed is a final administrative order of the Commission approving nuclear cost recovery amounts for Florida Power and Light Company and Progress Energy Florida, Inc. A copy of the Order is attached hereto as Exhibit "A." This appeal is filed pursuant to, *inter alia*: § 366.10, Florida Statutes; and Rule 9.030(a)(1)(B)(ii), Florida Rules of Appellate Procedure.

Respectfully submitted this 21st day of December, 2011.

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EXHIBIT "A"

FLORIDA PUBLIC SERVICE COMMISSION

ORDER NO. PSC-11-0547-FOF-EI

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause.	DOCKET NO. 110009-EI ORDER NO. PSC-11-0547-FOF-EI ISSUED: November 23, 2011

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
EDUARDO E. BALBIS
JULIE I. BROWN

APPEARANCES:

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On behalf of Florida Power & Light Company (FPL).

JOHN T. BURNETT, ESQUIRE, Progress Energy Florida, 299 First Avenue, N. PEF-151, St. Petersburg, FL 33701; JAMES MICHAEL WALLS and BLAISE N. HUHTA, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, FL 33601-3239
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Advisor to the Florida Public Service Commission.

FINAL ORDER APPROVING NUCLEAR COST RECOVERY AMOUNTS FOR FLORIDA POWER & LIGHT COMPANY AND PROGRESS ENERGY FLORIDA, INC.

BY THE COMMISSION:

Background

On March 1, 2011, Florida Power & Light Company (FPL) and Progress Energy Florida, Inc. (PEF) filed petitions seeking prudence review and final true-up of the 2009 and 2010 costs for certain nuclear power plant projects pursuant to Rule 25-6.0423, Florida Administrative Code (F.A.C.), and Section 366.93, Florida Statutes (F.S.). On May 2, 2011, FPL and PEF filed petitions seeking approval to recover estimated 2011 costs and projected 2012 costs. Both companies requested recovery of these costs through the Capacity Cost Recovery Clause (CCRC).

FPL's petitions addressed two nuclear projects. The first FPL project is composed of extended power uprate activities at its existing nuclear generating plants, Turkey Point Units 3 & 4 and St. Lucie Units 1 & 2 (EPU). FPL obtained an affirmative need determination for its extended power uprate project by Order No. PSC-08-0021-FOF-EI.[1] The second FPL project is the construction of two new nuclear generating units, Turkey Point Units 6 & 7 (TP67). FPL

[1] Order No. PSC-08-0021-FOF-EI, issued January 7, 2008, in Docket No. 070602-EI, In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plants, for exemption from Bid Rule 25-22.082, F.A.C. and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.

obtained an affirmative need determination for the two new nuclear generating units by Order No. PSC-08-0237-FOF-EI.[2]

PEF's petitions also addressed two nuclear projects. The first PEF project is a multi-phased uprate of its existing nuclear generating plant, Crystal River Unit 3 (CR3 Uprate). PEF obtained an affirmative need determination for the CR3 Uprate by Order No. PSC-07-0119-FOF-EI.[3] The second PEF project is the construction of two new nuclear generating units, Levy Units 1 & 2 (LNP). PEF obtained an affirmative need determination for the LNP by Order No. PSC-08-0518-FOF-EI.[4]

Traditionally, all eligible power plant construction projects have been afforded the same regulatory accounting and ratemaking treatment. That is, once the need for a project has been determined, the utility books all expenditures associated with the project into account 107 Construction Work in Progress (CWIP) for that particular project. A monthly allowance-for-funds-used-during-construction (AFUDC) rate is applied to the average balance of this account and the resulting dollar amount is then added to the account balance. This process continues until the completion of the project.

Once the plant is placed in commercial service, the CWIP account balance is transferred to the appropriate plant-in-service account and becomes part of the utility's rate base. The impacts of including the total project costs in a utility's rate base, as well as the impacts of additional plant operations expenses, are addressed during a subsequent proceeding wherein it is determined whether customer base rate charges should be changed in order to provide the opportunity to recover these costs.

In 2006, the Florida Legislature enacted Section 366.93, F.S., creating an alternative cost recovery mechanism, in order to encourage utility investment in nuclear electric generation in Florida. Section 366.93, F.S., authorized us to allow investor-owned electric utilities to recover certain construction costs in a manner that reduces the overall financial risk associated with building a nuclear power plant. In 2007, Section 366.93, F.S., was amended to include integrated gasification combined cycle plants, and in 2008, the statute was amended to include new, expanded, or relocated transmission lines and facilities necessary for the new power plant. The statute required the adoption of rules that provide for cost recovery for nuclear plant construction through the existing capacity cost recovery clause. Rule 25-6.0423, F.A.C., was adopted to implement Section 366.93, F.S.

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[2] Order No. PSC-08-0237-FOF-EI, issued April 11, 2008, in Docket No. 070650-EI, In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.

[3] Order No. PSC-07-0119-FOF-EI, issued February 8, 2007, in Docket No. 060642-EI, In re: Petition for determination of need for expansion of Crystal River 3 nuclear power plant, for exemption from Bid Rule 25-22.082, F.A.C., and for cost recovery through fuel clause, by Progress Energy Florida, Inc.

[4] Order No. PSC-08-0518-FOF-EI, issued August 12, 2008, in Docket No. 080148-EI, In re: Petition for determination of need for Levy Units 1 and 2 nuclear power plants, by Progress Energy Florida, Inc.

Pursuant to Rules 25-6.0423(4) and (5), F.A.C., once a utility obtains an affirmative need determination for a power plant covered by Section 366.93, F.S., the utility may petition for cost recovery using the alternative mechanism. Three types of prudently incurred costs are described in the rule:

- Site selection costs are costs incurred prior to the selection of a site. A site is deemed selected upon the filing for a determination of need. (Rule 25-6.0423(2)(e) and (f), F.A.C.)
- Preconstruction costs are those costs incurred after a site is selected through the date site clearing work is completed. (Rule 25-6.0423(2)(g), F.A.C.)
- Construction costs are costs that are expended to construct the power plant including, but not limited to, the costs of constructing power plant buildings and all associated permanent structures, equipment and systems. (Rule 25-6.0423(2)(i), F.A.C.)

In Order No. PSC-08-0749-FOF-EI, we approved stipulations among the parties to Docket No. 080009-EI, finding that site selection costs shall be treated in the same manner as pre-construction costs.[5] Pursuant to Section 366.93(2)(a), F.S., and Rule 25-6.0423(5), F.A.C., all prudently incurred preconstruction costs, as well as the carrying charges on prudently incurred construction costs, are to be recovered directly through the CCRC.

Rule 25-6.0423(5), F.A.C., sets forth the process by which we conduct our annual hearing to determine the recoverable amount that will be included in the CCRC pursuant to Section 366.93, F.S. This is the fourth year of the nuclear cost recovery clause roll-over docket (NCRC).

Intervention in the 2011 NCRC proceeding was granted to the following parties: the Office of Public Counsel (OPC), Florida Industrial Power Users Group (FIPUG), White Springs Agricultural Chemicals Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate), Southern Alliance for Clean Energy (SACE), and the Federal Executive Agencies (FEA). Testimony and associated exhibits were filed by FPL, PEF, OPC and our staff.

The evidentiary hearing for the FPL portion of the 2011 NCRC was held on August 10-11, 2011. The PEF portion of the evidentiary hearing was held on August 16-17, 2011.

On July 1, 2011, PEF filed a motion requesting us to defer our review of the long-term feasibility of completing the CR3 Uprate and our determination of the reasonableness of PEF's 2011 and 2012 CR3 Uprate expenditures and associated carrying costs until the 2012 NCRC proceedings. PEF provided revised testimony and positions reflecting the exclusion of any CR3 Uprate costs that may be incurred during 2011 and 2012. PEF's motion was unopposed and approved by us as a preliminary matter at the hearing on August 10, 2011. Consequently,

[5] In Docket No. 080009-EI, issued November 12, 2008, <u>In re: Nuclear cost recovery clause</u>.

resolution of CR 3 Uprate subject matter is deferred and the amounts shown in PEF's revised positions were approved. (See Attachment A)

On July 21, 2011, FPL filed a motion to strike certain portions of OPC witness Jacobs's testimony and certain proposed subject areas. On August 10, 2011, we heard oral arguments and denied FPL's motion to strike testimony. We determined that several OPC proposed subject areas were subsumed in other subject areas.

On August 16, 2011, during the PEF portion of the hearing, PEF, OPC, FIPUG, PCS Phosphate, SACE, and FEA offered a stipulation to resolve the remaining disputed CR3 Uprate matters. (See Attachment B) We approved the stipulation and the proposed resolution of the issues.

All parties, excluding FEA, filed post-hearing briefs on September 8, 2011, addressing the remaining unresolved issues. We have jurisdiction over these matters pursuant to Section 366.93, F.S., and other provisions of Chapter 366, F.S.

List of Acronyms and Abbreviations	
AFUDC	Allowance for funds used during construction
CC	Natural gas-fired combined cycle plant
CCRC	Capacity Cost Recovery Clause
COL	Combined operating license
COLA	Combined operating license application (NRC filing)
Commission	Florida Public Service Commission
Concentric	Concentric Energy Advisors
CPVRR	Cumulative present value revenue requirement
CR3 Uprate	Multi-phased uprate project at PEF's Crystal River Unit 3
CWIP	Construction work in progress
CO_2	Carbon dioxide
COD	Commercial operation date
EP	Engineering and procurement; a type of contract
EPC	Engineering, procurement and construction; a type of contract
EPU	Extended Power Uprate of St. Lucie Units 1&2 and Turkey Pt. Units 3&4
ESC	Executive Steering Committee
F.A.C.	Florida Administrative Code
FEA	Federal Executive Agencies
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
F.S.	Florida Statutes
IPP	Integrated project plan
kWh	Kilowatt-hour (1,000 watt-hours)
LAR	License amendment request (NRC filing)
LLE	Long lead equipment
LNP	Levy Units 1 & 2 project

List of Acronyms and Abbreviations	
NCRC	Nuclear Cost Recovery Clause
NRC	Nuclear Regulatory Commission
NO_X	Nitrogen Oxides
O&M	Operations and maintenance
OPC	Office of Public Counsel
PEF	Progress Energy Florida, Inc.
PCS Phosphate	White Springs Agricultural Chemicals Inc. d/b/a PCS Phosphate – White Springs
RMP	Rate management plan
SACE	Southern Alliance for Clean Energy
SEC	Security Exchange Commission
SMC	Senior Management Committee
SNF	Spent nuclear fuel
SO_2	Sulfur dioxide
TP67	Turkey Point Units 6&7

Decision

Florida Power & Light Company

I. Rate-Case Type Expense

This issue addresses whether any of FPL's costs for preparing, filing and otherwise presenting its 2010 NCRC case should be disallowed from recovery. This issue was framed during the 2010 NCRC Prehearing Conference.[6] Pursuant to our approved stipulation in Order No. PSC-11-0095-FOF-EI, at page 7, the resolution of this issue was deferred to this year's NCRC proceeding.[7]

FIPUG's position to disallow all rate case type expenses is not explained in its brief. OPC asserted resolution of this issue was related to matters encompassed in whether FPL willfully withheld information we needed to make an informed decision. SACE supported OPC's position and offered no further argument in its brief. FPL maintained that no rate case type expenses such as document shipping costs and copying costs are included in its NCRC amount, and thus no disallowance should be ordered.

We note that the record demonstrated that FPL included a percentage of the costs for witness testimony, errata, and hearing appearances in its NCRC recovery amount. However, FPL's expenses for mailings of discovery and testimony, airfare, hotels, car rentals, and duplication were not allocated to the NCRC. Thus, we agree with FPL's position that no costs are recovered through the NCRC except expenses for witness testimony and associated support.

[6] Docket No. 100009-EI prehearing transcript, Document number 06780-10, pages 12-22.
[7] Order No. PSC-11-0095-FOF-EI, issued February 2, 2011, in Docket No. 100009-EI, In re: Nuclear cost recovery clause.

FPL's estimated 2010 NCRC regulatory expenses and recovery mechanisms for the costs are presented in the following table.

FPL's Estimated 2010 NCRC Regulatory Expense

Descriptions	Amounts	% NCRC Recovery	Recovery Mechanisms: NCRC	Recovery Mechanisms: Base Rates
2010 Testimony				
Witnesses & Support	$ 695,949	49.0%	$ 341,015	$ 354,934
Docket Expenses	$ 6,439	0.0%	$ 0	$ 6,439
2010 Errata				
Witnesses & Support	$ 18,067	37.0%	$ 6,685	$ 11,382
Docket Expenses	$ 1,072	0.0%	$ 0	$ 1,072
2010 Hearing				
Witnesses & Support	$ 251,060	55.0%	$ 138,083	$ 112,977
Docket Expenses	$ 110,000	0.0%	$ 0	$ 110,000
Total				
Witnesses & Support	$ 965,076	50.3%	$ 485,783	$ 479,293
Docket Expenses	$ 117,511	0.0%	$ 0	$ 117,511

When FPL witness Powers was questioned regarding FPL's 2010 rate-case type expenses, she affirmed that a portion of expenses for witnesses and support were recovered through the NCRC. Concerning the 2010 errata expenses, witness Powers opined, and we agree, that FPL was required to file errata to correct errors it detected so that the testimony and exhibits were accurate.

We do not find that FPL improperly incurred any of its 2010 NCRC rate case type expenses. Thus, no 2010 Nuclear Cost Recovery Clause rate-case type expense shall be disallowed from recovery.

II. FPL's TP67 Activities Qualify Under Section 366.93, F.S.

Section 366.93, F.S., provides for advanced cost recovery for utilities engaged in the siting, design, licensing, and construction of nuclear power plants. In Order No. PSC-11-0095-FOF-EI, we ruled on this identical issue concerning PEF; we interpreted this statutory provision to include the building of new nuclear power plants and the modification of existing nuclear power plants.[8] The main question in analyzing this issue, as discussed in Order No. PSC-11-

[8] Order No. PSC-11-0095-FOF-EI, issued on February 2, 2011, in Docket No. 100009-EI, In re: Nuclear cost recovery clause.
See also Order No. PSC-08-0749-FOF-EI, issued on November 12, 2008, in Docket No. 080009-EI, In re: Nuclear Cost Recovery Clause; and Order Nos. PSC-09-0783-FOF-EI, issued on November 11, 2009, in Docket No. 090009-EI, In re: Nuclear Cost Recovery Clause.

0095-FOF-EI, is whether a utility must engage in the siting, design, licensing, and construction of nuclear power plant activities simultaneously in order to meet the statutory requirements of Section 366.93, F.S.

FIPUG and SACE contended that FPL's actions do not comport with the purpose of the statute, which is to promote investment in nuclear energy through the siting and ultimate construction of nuclear power plants. They argued that FPL's decision to "create an option" to construct or not construct TP67 is direct evidence that FPL has failed to demonstrate its continued intent to build the nuclear power plants as contemplated by Order No. PSC-11-0095-FOF-EI and Section 366.93(1)(f), F.S. FIPUG and SACE contended that FPL's own testimony demonstrated that actual construction of the TP67 project is tentative and uncertain at best; thus, FPL has failed to meet the requirements of Section 366.93(1)(f), F.S. They asserted that FPL's witness Scroggs admitted as much when he testified that the "decision [whether or not to construct] is going to be based on the economics and the events as they unfold over the next several years," as well as the fact that the projects are at "early uncertain periods." FIPUG and SACE also cited to FPL's witness Olivera's testimony in support of their position:

> Our intentions are to go through the licensing process. When (we) have the COLA application approved, I think we will look at, you know, what is happening, what do we think is the most likely demand outlook for the state. You know, does this project – is the project needed?

Thus, they argue that FPL's activities relating to TP67 do not meet the intent requirement set out by our Order in Order No. PSC-11-0095-FOF-EI.

FIPUG and SACE also contended that FPL's actions do not demonstrate the intent to actually construct the nuclear power plant as required by Order No. PSC-11-0095-FOF-EI. FIPUG and SACE assert that FPL's decision to cancel and/or delay all construction activities for the TP67 project, failure to enter into an Engineering Procurement (EP) or Engineering, Procurement and Construction (EPC) contract, extension of its forging reservation agreement four times, failure to procure long-lead materials, and withdrawal of its Limited Work Authorization from the Nuclear Regulatory Commission (NRC), demonstrate a lack of intent to actually construct the nuclear power plants.

FPL argued that it demonstrated the intent to actually construct TP67 consistent with Order No. PSC-11-0095-FOF-EI. FPL contended that in 2009 and 2010, it worked to achieve or support the continuing review of the licenses and other approvals needed to construct the TP67 project. FPL witness Scroggs asserted that FPL continued negotiations for a land exchange agreement with the Everglades National Park and approval of a Comprehensive Development Master Plan amendment for roadway improvements needed for construction activities. Also during that time, FPL sought approval and execution of a Joint Participation Agreement for reclaimed water from Miami-Dade County for the TP67 project's cooling water needs. Thus, FPL satisfies the intent requirement of Order No. PSC-11-0095-FOF-EI, and any costs FPL incurred during 2010 associated with the aforementioned activities are preconstruction costs, which are recoverable pursuant to Sections 366.93(1)(f) and (2)(a), F.S.

Also, FPL contended that it intends to pursue completion of TP67 project by obtaining the licenses and approvals necessary to construct and operate the plant. FPL's witness Dr. Diaz, former chairman of the NRC and FPL NRC consultant, testified that "the primary focus of the current stage of the project should be to obtain the necessary federal, state, and local approvals for construction and operation of the Turkey Point 6 & 7 project." FPL asserted that this is a deliberate, stepwise approach that strikes a balance between maintaining progress of the project and managing the risk by managing commitments. Moreover, its risk-mitigating actions should be commended, not used in an attempt to cast doubt on its commitment to the project. FPL asserted that executing an EP or EPC contract was not necessary at this time to maintain the current project schedule. FPL's witness Scroggs explained that FPL need not initiate long lead procurement until 2015 to maintain the current schedule. FPL contended that if it were to proceed with the alternative, as advocated by SACE and FIPUG, and entered into an EP or EPC contract and/or secured long lead material, it would have to commit substantial sums of money that are not necessary at this time to lock down construction plans now, despite the regulatory, commercial, economic, and other uncertainty surrounding the project.

Based upon our analysis of the applicable statute, our prior Orders, and prior Florida case law, we do not find that a utility must engage in the siting, design, licensing, and construction of nuclear power plant activities simultaneously in order to meet the statutory requirements of Section 366.93, F.S. We note our decision in Order No. PSC-11-0095-FOF-EI, where we found that a utility must continue to demonstrate its intent to build the nuclear power plant for which it seeks advance recovery of costs to be in compliance with Section 366.93, F.S. As discussed in that Order, we find that there are various phases of constructing a nuclear power plant, including the siting, design, licensing, and building of the plant. These phases generally cannot occur simultaneously. As stated in Order No. PSC-11-0095-FOF-EI, Section 366.93(1)(f), F.S., contemplates that there are various phases of constructing a nuclear power plant by explicitly establishing demarcations of what is preconstruction and what is construction of a nuclear power plant. For example, Section 366.93(1)(f), F.S., defines the word "preconstruction." Under the statute:

> Preconstruction is that period of time after a site, including any related electrical transmission lines or facilities, has been selected through and including the date the utility completes site clearing work. Preconstruction costs shall be afforded deferred accounting treatment and shall accrue a carrying charge equal to the utility's allowance for funds during construction (AFUDC) rate until recovered in rates.

Furthermore, Section 366.93(2)(a), F.S., provides that recovery of any preconstruction costs will occur through the Capacity Cost Recovery Clause. Rule 25-6.0423(2)(h), F.A.C., which implements Section 366.93(1)(f), F.S., provides:

> Site selection costs and pre-construction costs include, but are not limited to: any and all costs associated with preparing, reviewing and defending a Combined Operating License (COL) application for a nuclear power plant; costs associated with site and technology selection; costs of engineering, designing, and permitting

> the nuclear or integrated gasification combined cycle power plant; costs of clearing, grading, and excavation; and costs of on-site construction facilities (i.e., construction offices, warehouses, etc.).

We find that FPL's costs related to its activities for the TP67 project qualify as recoverable preconstruction costs as defined in Section 366.93(1)(f), F.S., and as interpreted by Rule 25-6.0423(2)(h), F.A.C. Similar to our determination that PEF's costs for the Levy projects qualified as preconstruction costs under Section 366.93(1)(f), F.S., we find that FPL's costs for the TP67 project also qualify as preconstruction costs under Section 366.93(1)(f), F.S.[9] FPL incurred costs associated with its continued pursuit of the licenses and approvals necessary to construct and operate a nuclear power plant from both state and federal governments. In 2009 and 2010, FPL continued negotiations for a land exchange agreement with the Everglades National Park and approval of a Comprehensive Development Master Plan amendment for roadway improvements needed for construction activities. Also during that time, FPL sought approval and execution of a Joint Participation Agreement for reclaimed water from Miami-Dade County for the TP67 project's cooling water needs. Thus, any costs FPL incurred during 2010 associated with the aforementioned activities are preconstruction costs, which are recoverable pursuant to Sections 366.93(1)(f) and (2)(a), F.S. Therefore, a strict interpretation of Section 366.93, F.S., to require a utility to engage in the siting, design, licensing, and construction of nuclear power plant activities simultaneously, would be an incorrect interpretation of the statute, and inconsistent with our precedent.

We note that we have previously allowed nuclear cost recovery since the inception of the NCRC without requiring the siting, design, licensing, and construction of nuclear power plant activities to occur simultaneously.[10] We allowed FPL to recover costs associated with the licensing activities for the TP67 project after finding those costs reasonable and prudent. FPL did not have an engineering, procurement, or construction contract for TP67, and did not intend to enter into such a contract until some point in the future. Also, we approved PEF's preconstruction costs last year without requiring the siting, design, licensing, and construction of nuclear power plant activities to occur simultaneously. In Order No. PSC-11-0095-FOF-EI, we stated that a utility must continue to demonstrate its intent to build the plant for which it seeks advance recovery of costs. Order No. PSC-11-0095-FOF-EI, at 6.

We acknowledge FIPUG's and SACE's concerns that FPL's "create an option" approach and FPL's primary focus on pursuing a combined operating license (COL) from the NRC before moving forward with other phases of the project, could be interpreted as FPL not intending to actually construct TP67. We also recognize the potential pitfalls that might result from FPL's "option creation" approach. However, we find that FPL continues to demonstrate its intent to build the TP67 nuclear power plant. As stated above, FPL continues to pursue licenses and the

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[9] Order No. PSC-11-0095-FOF-EI, issued on February 2, 2011, in Docket No. 100009-EI, In re: Nuclear cost recovery clause.

[10] Order No. PSC-11-0095-FOF-EI, issued on February 2, 2011, in Docket No. 100009-EI, In re: Nuclear cost recovery clause; Order No. PSC-08-0749-FOF-EI, issued on November 12, 2008, in Docket No. 080009-EI, In re: Nuclear Cost Recovery Clause; and Order No. PSC-09-0783-FOF-EI, issued on November 11, 2009, in Docket No. 090009-EI, In re: Nuclear Cost Recovery Clause.

approvals necessary to construct and operate TP67 from both state and federal governments. FPL has maintained its reservations with the manufacturers of long-lead material by negotiating several extensions. In 2009 and 2010, FPL continued negotiations for a land exchange agreement with the Everglades National Park and for approval of a Comprehensive Development Master Plan amendment for roadway improvements needed for construction activities. Also during that time, FPL sought approval and execution of a Joint Participation Agreement for reclaimed water from Miami-Dade County for the TP67 project's cooling water needs. Therefore, we find that FPL has demonstrated its intent to build the TP67 nuclear power plant through 2010. FPL's activities related to TP67 qualify as siting, design, licensing, and construction of a nuclear power plant as contemplated by Section 366.93, F.S.

III. 2010 and 2011 Annual Detailed Analyses of the Long-term Feasibility of Completing the Turkey Point 6 & 7 Project

This issue addresses review and approval of FPL's detailed long-term feasibility analysis of continuing construction and completing the TP67 project as required by Rule 25-6.0423, F.A.C., and Order No. PSC-08-0237-FOF-EI.

In an effort to mitigate the economic risks associated with the long lead-time and high capital costs associated with nuclear power plants, the Florida Legislature enacted Sections 366.93 and 403.519(4), F.S., during the 2006 legislative session. Section 366.93(2), F.S., requires us to establish, by rule, alternative cost recovery mechanisms for the recovery of costs incurred in the siting, design, licensing, and construction of a nuclear power plant. We adopted Rule 25-6.0423, F.A.C., to satisfy the requirements of Section 366.93(2), F.S. Rule 25-6.0423(5)(c)5, F.A.C., states:

> By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long term feasibility of completing the power plant.

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

> FPL shall provide a long-term feasibility analysis as part of its annual cost recovery process which, in this case, shall also include updated fuel forecasts, environmental forecasts, breakeven costs, and capital cost estimates. In addition, FPL should account for sunk costs. Providing this information on an annual basis will allow us to monitor the feasibility regarding the continued construction of Turkey Point 6 and 7.[11]

We find that FPL satisfied the requirements of Order No. PSC-08-0237-FOF-EI through various means. FPL's feasibility analysis for completion of TP67 project remained consistent with the methodology it used in the need determination and each subsequent NCRC proceeding.

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[11] Order No. PSC-08-0237-FOF-EI, issued April 11, 2008, in Docket No. 070650-EI, In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.

Stated most simply, FPL compared competing resource plans, one with the nuclear resource option and one with a non-nuclear resource option. The competing, non-nuclear resource option is a new highly fuel-efficient combined cycle (CC) generating unit of the type FPL is constructing at its Cape Canaveral and Riviera plant sites. In evaluating these options, FPL considered numerous quantitative and qualitative factors. Among the quantitative factors that FPL examined were fuel and environmental price forecasts, project costs, and cost-effectiveness using multiple sensitivities for fuel and environmental costs. Qualitative factors considered included regulatory feasibility, technical feasibility, funding feasibility, and joint ownership. We examined each of these factors to determine the acceptability of FPL's long-term feasibility analysis.

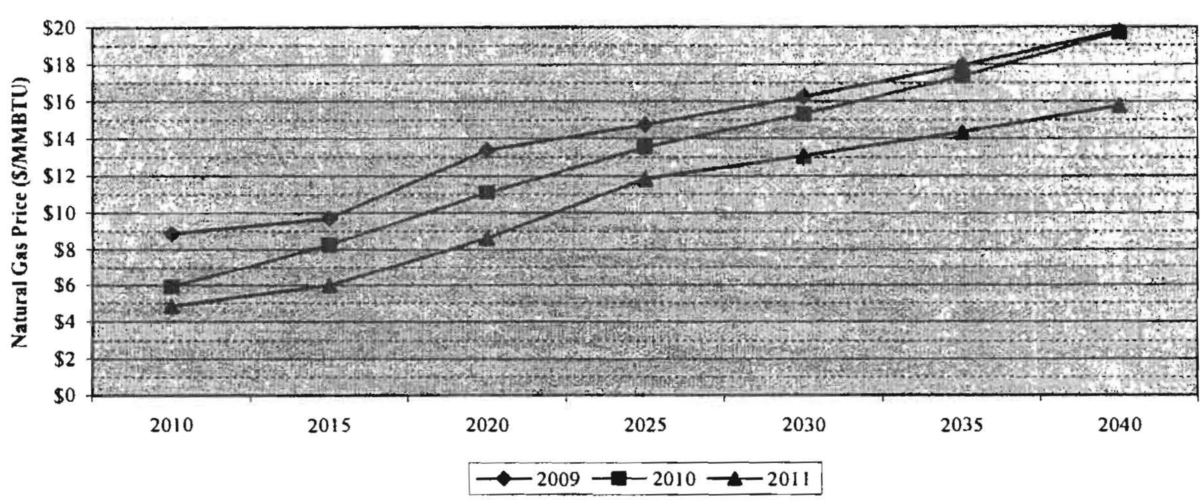
We find that the forecasts, cost estimates, and cost-effectiveness analyses are necessary filing requirements to assess FPL's 2011 TP67 project feasibility analysis. In addition, we reviewed regulatory and technical aspects of the project. These elements provide a holistic perspective for our review and approval regarding the acceptability of FPL's detailed long-term feasibility analysis.

A. Economic Feasibility

1. Updated Fuel Forecast

The updated fuel price forecasts submitted by FPL were developed from the same industry-accepted sources FPL has used since the need determination proceeding. Therefore, we find that it is reasonable to accept FPL's updated fuel cost data in this proceeding. The table below depicts the price forecasts for the medium range of natural gas used from the 2009 NCRC proceeding through this year's filing to support FPL's feasibility analysis. We note that the increases in natural gas price forecasts are trending slightly downward each year.

Forecasted Natural Gas Prices – Medium Fuel Forecast ($/MMBTU)



While none of the parties contested the accuracy or credibility of FPL's fuel forecast, SACE contended that FPL failed to take into account the declining natural gas costs, among other factors, in performing its feasibility analysis. SACE discounted the credibility of FPL's feasibility analysis stating that, although natural gas prices are trending downward for a period of at least 30 years, FPL's analysis "still purports to show TP67 as cost-effective." Absent in SACE's argument, however, is any evidence to suggest declining fuel prices make the TP67 project not cost-effective. SACE, instead, attempted to suggest the project should be abandoned and cost recovery rejected, not because the project was not cost-effective, but because the project was not as cost-effective as when fuel costs were higher.

SACE also highlighted the $20 billion reduction in fuel savings since the 2010 NCRC proceeding. FPL Witness Sim explained that the savings reduction was the impact of lower gas costs over the 40-year life of TP67. He noted that FPL customers would still benefit from $75 billion in fuel savings over the life of the new nuclear plants. Witness Sim concluded this portion of his cross-examination by testifying, "The project was projected to be solidly cost-effective last year, it is also projected to be solidly cost-effective this year despite the drop in those fuel costs."

We reject SACE's contention that FPL failed to consider the decline in forecasted gas prices. FPL's analysis shows that both the total cost difference between the competing plans and breakeven costs have declined due, in part, to the lower forecasted gas prices. In addition, SACE's acknowledgement that FPL has shown a decline in savings over the life of the project demonstrates that FPL has not failed to take into account the declining natural gas costs. Other intervenors did not contest FPL's fuel forecasts.

2. Updated Environmental Forecast

The updated environmental cost forecasts FPL submitted were developed from the same industry-accepted sources FPL has used since the need determination proceeding. The table below depicts the price forecasts for the medium range of environmental costs used from the 2009 NCRC proceeding through this year's filing to support FPL's feasibility analysis. We note that the price forecast for sulfur dioxide (SO_2) and nitrous oxides (NOx) dropped dramatically in 2011. FPL witness Sim testified that these reductions were due to utilities, in response to Environmental Protection Agency rules, adding control devices for these emissions. This, in turn, produces more emission allowances on the market in future years, thereby reducing the value of the allowances. None of the intervenors contested FPL's updated environmental forecast.

Forecasted Environmental Compliance Costs ($/ton)

Selected Years	Yearly Forecasted SO_2 Compliance Cost ($/ton)			Yearly Forecasted NO_x Compliance Cost ($/ton)			Yearly Forecasted CO_2 Compliance Cost ($/ton)		
	2009	2010	2011	2009	2010	2011	2009	2010	2011
2015	$2,013	$2,176	$58	$1,375	$2,071	$522	$17	$20	$0
2020	$3,164	$3,257	$66	$2,162	$3,100	$590	$27	$30	$32
2025	$4,988	$4,882	$74	$3,408	$1,257	$668	$43	$44	$47
2030	$4,453	$5,319	$84	$1,545	$1,085	$756	$67	$67	$68
2035	$3,691	$4,293	$95	$0	$1,228	$855	$101	$100	$98
2040	$2,653	$3,278	$108	$0	$1,389	$968	$149	$149	$141

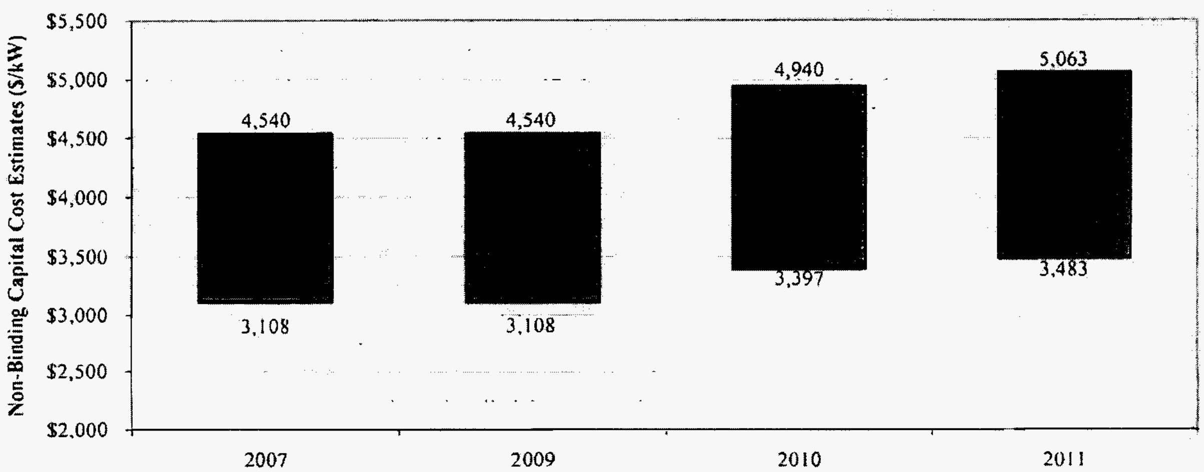
Source: EXH 99, p. 38; EXH 90

We note that FPL's feasibility (cost-effectiveness) analysis demonstrates changes in the forecasted cost of emissions were considered. We accept FPL's updated environmental cost data in this proceeding.

3. Updated Project Cost Estimate

FPL's current non-binding estimated range of capital cost is $3,483 to $5,063 per kilowatt in overnight costs. Adding carrying costs of $2.3 billion to $3.4 billion, and sunk costs, $0.1 billion, yields a total cost range of $12.8 billion to $18.7 billion. The estimated capital cost range represents an 11.5 percent increase from FPL's estimated maximum cost in the 2007 need determination proceeding and a 12.1 percent increase in the minimum cost. The history of cost estimates is shown below.

Range of Non-Binding Capital Cost Estimates ($/kW)



No party contested FPL's estimated cost. FPL used its updated project cost estimate in conducting its cost-effectiveness analysis below. We find that FPL's cost estimate is reasonable. Results of the analysis demonstrate that the cost-effectiveness of the project has declined in comparison with the competing plan without nuclear generation.

4. Project Cost-Effectiveness

FPL's analysis of the cost-effectiveness of completing the TP67 project once again relied on the same breakeven analysis it has used since the need determination. FPL compared a present value revenue stream assuming no capital costs for the nuclear units to a traditional present value revenue stream which includes capital and system fuel costs for a CC unit as a replacement for the nuclear units. The results of this analysis show the highest capital costs at which nuclear generation would still be cost-effective compared to the CC alternative.

FPL performed its analysis under a wide range of scenarios which combined varying fuel forecasts (low, medium, and high) and environmental compliance cost projections. , ENV I-III. ENV I represented a low compliance cost scenario, while ENV III represented a higher compliance cost scenario. Seven different fuel/environmental cost scenarios were analyzed for each alterative to TP67. The projected present value savings over the study period for each scenario was then used to calculate a breakeven capital cost estimate of what the nuclear units could cost and still produce net savings over the study period when compared to the CC units. Each breakeven value was then compared to the capital cost range of $3,483/kw-$5,063/kw to determine the likelihood of the nuclear project producing a net savings over the study period. If the breakeven values are higher than the current capital cost-estimates, then the nuclear plants would provide net savings over the life of the units compared to alterative baseload units. We find that FPL's approach in performing this analysis is still reasonable.

2011 Feasibility Analyses Results for TP67
Total Costs, Total Cost Differentials, and Breakeven Costs for All
Fuel and Environmental Compliance Cost Scenarios in 2011$
(millions, CPVRR, 2011 - 2063)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans: Plan with TP67	Total Costs for Plans: Plan without TP67	Total Cost Difference Plan with TP67 minus Plan without TP67	Breakeven Nuclear Capital Costs ($/kw in 2011$)
High Fuel Cost	Env I	201,647	216,541	(14,894)	6,911
High Fuel Cost	Env II	213,843	229,761	(15,918)	7,388
High Fuel Cost	Env III	240,894	259,588	(18,694)	8,679
Medium Fuel Cost	Env I	178,817	191,562	(12,744)	5,911
Medium Fuel Cost	Env II	190,705	204,474	(13,770)	6,389
Medium Fuel Cost	Env III	217,404	233,962	(16,558)	7,685
Low Fuel Cost	Env I	155,743	166,327	(10,584)	**4,907**

Note: A negative value in Column (5) indicates that the Plan with TP67 is less expensive than the Plan without TP67.
Conversely, a positive value in Column (5) indicates that the Plan with TP67 is more expensive that the Plan without TP67.

2010 Feasibility Analyses Results for TP67
Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2010$
(millions, CPVRR, 2010 - 2063)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans (2010$)		Total Cost Difference Plan with TP6 7 minus Plan without TP67 (2010$)	Breakeven Nuclear Capital Costs ($/kw in 2010$)
		Plan with TP67	Plan without TP67		
High Fuel Cost	Env I	204,049	220,743	(16,694)	7,637
High Fuel Cost	Env II	215,460	233,199	(17,739)	8,116
High Fuel Cost	Env III	240,986	261,237	(20,251)	9,267
Medium Fuel Cost	Env I	177,852	192,116	(14,264)	6,524
Medium Fuel Cost	Env II	189,240	204,550	(15,310)	7,003
Medium Fuel Cost	Env III	214,289	232,117	(17,828)	8,156
Low Fuel Cost	Env I	151,671	163,510	(11,839)	5,413

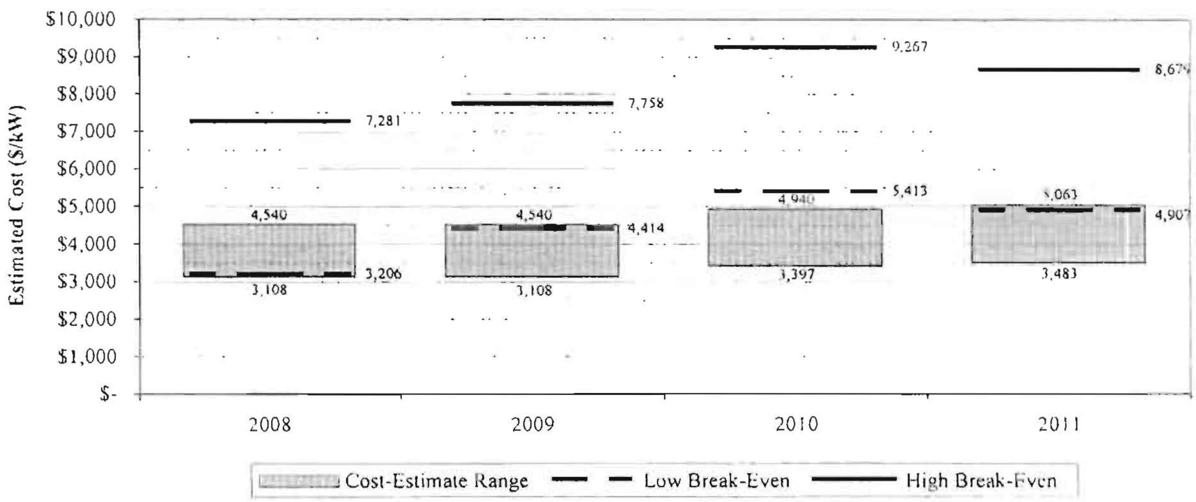
Note: A negative value in Column (5) indicates that the Plan with TP67 is less expensive than the Plan without TP67.
Conversely, a positive value in Column (5) indicates that the Plan with TP67 is more expensive that the Plan without TP67.

The results of the breakeven analysis, shown in the table above, demonstrate that the TP67 project remains cost-effective compared to the alternative CC unit. The results in 6 of the 7 scenarios show breakeven nuclear capital costs are above FPL's estimated range of costs, which demonstrates a high likelihood for cost-effectiveness. We note that the low fuel/low environmental cost scenario breakeven nuclear capital cost, $4,907 million, is within FPL's estimated range of costs, $3,483 million to $5,063 million. This indicates a possibility that the nuclear project may not be cost-effective if the capital costs approach the upper limit of the range and long-term fuel and environmental costs remain relatively low for the duration of the analysis (52 years).

We note that FPL's breakeven analyses for 2011 compared to 2010, in the table above, demonstrates that the magnitude and range of the breakeven nuclear capital costs have declined. In addition, the 2010 analysis showed the project was cost-effective in 7 of the 7 scenarios. The 2011 analysis shows the project is cost-effective in only 6 of 7 scenarios.

The table below portrays the migration of the breakeven costs and the estimate project costs. If the estimated capital cost range increases into the range of the breakeven costs, the project becomes less cost-effective. In 2010, the upper limit of breakeven cost was 88 percent greater and the lower limit was 10 percent greater than the highest estimated capital costs. In 2011, the upper limit of breakeven costs was 71 percent greater and the lower limit was 3 percent below the highest estimated capital costs. This indicated that the range and magnitude of breakeven costs have decreased since 2010. The lowest 2011 breakeven cost now being within the range of the estimated costs, as mentioned above, suggested that the project may not be cost-effective if long-term fuel and environmental costs remain low. We note, however, that 2011 is not the first year the lowest breakeven cost has been within the range of estimated costs. As the table below shows, the same situation was reported in both the 2008 need determination and 2009 NCRC orders.

2008 – 2011 Breakeven and Estimated Capital Cost Range Comparison



SACE argued that FPL improperly skewed the results of the cost-effectiveness analysis by omitting sunk costs. However, we find that FPL witness Sim more convincingly explained that including sunk costs in a cost-effectiveness analysis of whether to go forward with a project would violate a well-accepted economic analysis principle of Rule 25-6.0423(5)(c)5, F.A.C., and Order No. PSC-08-0237-FOF-EI. Witness Sim estimated that by hypothetically violating that guidance and adding sunk cost to the cost-effectiveness analysis, the TP67 project would appear less cost-effective, but would still be cost-effective nonetheless. In addition, FPL reported that sunk costs for 2011 were $129 million. We note that the reported sunk costs were 1.0 to 0.7 percent of the total estimated cost range in 2011, $12.8 billion to $18.7 billion, respectively.

In addition, OPC witness Smith testified, "If previous costs were prudently incurred and are allowed to be included in rate base, then excluding them in current and future feasibility analyses is appropriate." We have previously found FPL's NCRC costs have been prudently incurred.

We find that SACE's argument unpersuasive. Rule 25-6.0423(5)(c)5, F.A.C., requires a "detailed analysis of the long term feasibility of completing the power plant." In Order No. PSC-08-0237-FOF-EI, we required information about "the continued construction of Turkey Point 6 and 7." In determining the cost of going from "A" to "B" for two competing projects, it would be illogical to consider any costs prior to "A," i.e. sunk costs. Including costs prior to "A" would constitute a hindsight review which is not the purpose of a feasibility analysis that examines the wisdom of continuing a project from its current position forward to completion. Other parties to the proceeding did not contest FPL's cost-effectiveness analysis methodology or results.

We observed that FPL's consideration of lower forecasted prices for natural gas and emissions have reduced the cost-effectiveness of the TP67 project; however, completing the project remains cost-effective at this time. We shall accept FPL's cost-effectiveness analysis.

B. Regulatory Feasibility

SACE asserted that FPL's feasibility analysis should be rejected and cost recovery be denied because FPL failed to conduct a "detailed analysis" of the ability to obtain all approvals, the ability to obtain financing, and supportive state and federal energy policy. SACE attempted to paint a picture of insurmountable regulatory uncertainty, to the point SACE claimed, "FPL's feasibility analyses for 2010 and 2011 fail to demonstrate that completion of TP67 remains feasible in the long-term, as the analyses simply fail to properly and fully account for all of the uncertain [sic] and risk currently surrounding new nuclear generation in the United States."

In contrast, FPL witness Scoggs testified about FPL's continuing review of numerous regulatory issues, such as the NRC combined license schedule, the Florida Site Certification process, and negotiations for land, roadway improvements, and water supply. Witness Scoggs presented numerous pages in his prefiled testimony discussing the many activities at local, state, national, and international levels that FPL follows closely, and the intensive review process used to identify potential impacts on the TP67 project.

Both SACE and FIPUG argued that the regulatory impacts of the Japanese Fukushima Daiichi nuclear plant disaster will likely introduce regulatory uncertainties and time delays as the NRC implements interim actions while final rulemaking is in progress. Both intervenors also placed considerable weight on FPL witness Scrogg's testimony about the events in Japan. Witness Scroggs best summarized the regulatory feasibility during cross-examination:

> But, you know, the recent indications are that things remain on track. The Nuclear Regulatory Commission in the past week have continued the process for approving the AP1000 by issuing a final safety evaluation report, and similarly issued a final safety evaluation report for the Vogtle projects in Georgia, which are the reference COLA for this project.

We find that FPL has an effective process in place to provide its management with an ongoing, detailed analysis of the uncertainties and risks that could impact its licensing, approval, and certifications necessary for project success.

C. Technical Feasibility

Closely related to regulatory issues are some technical issues with the Westinghouse AP1000 nuclear power units planned for the TP67 project. First is the NRC certification of the latest design change to the AP1000. This process must be completed prior to a Combined Operating License being issued. While Westinghouse received a Final Design Certification for the AP1000 in 2006, the latest design change is in the process of certification. However, several hurdles in the process have been completed. The NRC staff issued its Advanced Final Safety Evaluation, the Advisory Committee on Reactor Safeguards accepted the AP1000 design as safe to build and operate, and the NRC published for comment the proposed rule that would amend Westinghouse's certified AP1000 reactor design for use in the United States. The current NRC published schedule expects the AP1000 Design Change rulemaking to be issued by approximately September 2011.

A second issue is storage of spent nuclear fuel (SNF). The U.S. Department of Energy has terminated work toward establishing a SNF storage site in Yucca Mountain, Nevada, and requested withdrawal of its licensing application from the NRC. Therefore, it appears there will be no central storage location for such highly radioactive materials for some time. FPL witness Diaz explained that the NRC issued a revised Waste Confidence rule in December 2010. The new rule found, among other things, "reasonable assurance that, if necessary, SNF can be stored safely and without significant environmental impacts at reactor sites for at least 60 years beyond the licensed life for operation of that reactor." Witness Diaz further testified,

> In my view, the revised Waste Confidence rule will enhance the viability of the licensing, construction, and operation of the Turkey Point 6 & 7 Project by precluding litigation of SNF issues in the licensing proceeding for Turkey Point Units 6 and 7.

Finally, intervenors expressed skepticism that FPL's new nuclear units would remain safe after such events as the Japanese Fukushima Daiichi nuclear plant disaster. To that concern, FPL witness Diaz testified,

> The current generation of nuclear power plant designs that are the subject of COLAS, such as the Westinghouse AP1000 design that is referenced in the Turkey Point Units 6 & 7 COLA, are more robust than the existing plants in the areas shown to be compromised by the earthquake/tsunami combination in Japan.

Based on the evidence in the record, we find that the TP67 project is still technically feasible.

D. Funding Feasibility

In addition to elements of economic feasibility, we find that the availability of funding for the project shall also be considered. FPL witness Scoggs testified, "Recent activity on predecessor projects shows a strong interest in the investment community to participate in new nuclear financing." He provided examples of a successful bond solicitation for a portion of the Vogtle Project in Georgia at rates under 5 percent. None of the intervenors contested FPL's ability to obtain funding for the project.

We find that FPL's current access to capital markets as confirmation of continued funding feasibility.

F. Joint Ownership

The parties did not suggest that the TP67 project is less viable for lack of existing or potential joint owners. FPL witness Scoggs discussed the periodic meetings he had with other utilities from Florida about the status of the project and, most recently, about the events at Fukushima. Witness Scoggs explained that, because of where FPL currently is in the project, it would not be an appropriate time to enter into a joint ownership agreement. The absence of any comment about joint ownership of TP67 in FIPUG's post-hearing brief suggests FIPUG did not see this as a concern for the FPL project. No other intervenors contested FPL's consideration of joint ownership.

We agree with Witness Scoggs. The project is still in its early stages with many uncertainties, associated risks, and pending NRC licensing. Given the current status of the project, we find that the lack of joint ownership shall not be deemed a fatal flaw to project feasibility at this time.

G. Conclusion

We find that based on the preponderance of the evidence, FPL has fully considered the economic, regulatory, technical, funding, and joint ownership considerations impacting the feasibility of the project. While continuing uncertainty exists in virtually all these areas, we find that the TP67 project continues to appear feasible at this time.

IV. Reasonableness of Pursuing TP67 Combined Operating License

We next address the reasonableness of FPL's decision to continue pursuing a COL for the TP67 project. We note that acquiring a COL is a prerequisite for the safety-related construction and operation of a nuclear power plant.[12] Reference to COL activities therefore serves to show the TP67 project status as progressing towards commercial operation as opposed to project cancellation.

SACE's position in this issue is based on its view that completing the project is not feasible. Both SACE and FIPUG argued in their briefs that FPL's intent is to create an option. FPL witness Scroggs provided testimony that FPL's efforts were to create or develop the option for new nuclear generation. FIPUG argued that FPL's wording created uncertainty about the status of the project as an attempt to keep the nuclear option open rather than committing to moving forward with the TP67 project. In support of their position, both FIPUG and SACE noted that FPL had not entered into an EPC type of agreement. However, we note that there was no record evidence that it would have been reasonable or prudent for FPL to enter into an EPC type of agreement at this stage in the TP67 project. Similarly, there is no record evidence that FPL could complete the TP67 project without the prerequisite COL approval from the NRC.

[12] 10 CFR § 50.10(c) and 10 CFR § 52.103(g).

FPL witness Scroggs stated that the primary focus of the current phase of the project has been, and remains obtaining the necessary federal, state and local approvals that will define the project and enable construction and operation of the TP67 project. Witness Scroggs presents three current significant licensing activities that began in 2008: Florida Site Certification, U.S. Army Corps. Of Engineers Environmental Permits, and NRC Combined License. He also listed a total of 46 required federal, state and local authorizations. We note that no party raised concerns with 45 of the 46 permitting activities that show progress towards commercial operation as opposed to project cancellation. These other activities are also prerequisites for the construction and operation of a nuclear power plant.

FPL witness Scroggs explained that the project was being developed, managed, and controlled to create the option for more reliable, cost-effective and fuel diverse nuclear generation to benefit FPL's customers under the earliest practical deployment schedule. He explained that the option is about when FPL exercises its intent to construct. We note that proceeding with the COL activities at this time is consistent with FPL's asserted goal of earliest practical deployment schedule because the various licenses, once received, will help define the scope of the TP67 project earlier than a delay or suspension in COL activities would.

Witness Scroggs addressed various alternative project paths and FPL's reasoning for its decision to maintain progress on licenses and permits. Audit staff witnesses Fisher and Rich, jointly, reviewed FPL's project management controls and offered no specific recommendations other than continued monitoring. OPC witness Jacobs reviewed the status of the TP67 project and FPL's project management, and did not taking issue with FPL's approach. FPL witness Reed also reviewed FPL's management of the TP67 project and opined that FPL acted properly in reaction to protracted licensing and permitting processes, as well as uncertainty related to external risk factors.

We addressed a similar issue for PEF in the 2010 NRC proceeding concerning PEF's LNP activities.[13] Our decision concerning PEF's pursuit of a COL in Order No. PSC-11-0095-FOF-EI stated:

> Notwithstanding, PEF asserted that its decision to continue the LNP was reasonable and is not rendered unreasonable simply because intervenors prefer a different or a conditional decision. The fundamental question is what energy policy the State of Florida wants to support. PEF believes that nuclear continues to be an important part of the long-term energy mix and that to walk away from this project would be a mistake. PEF witness Lyash characterized his feeling about the project as ". . . not bullish, but eyes wide open to both the costs and the benefits." These are the same benefits that the Florida Legislature recognized in the 2006 legislation and we recognized in granting the need determination for the LNP. These benefits include fuel diversity, carbon free generation, reduced reliance on fossil fuels, and an estimated $100 billion in fuel savings to customers over the 40 years of operation.

[13] PSC-10-0538-PHO-EI, issued August 20, 2010, in Docket No. 100009-EI, In re: Nuclear cost recovery clause, at page 28.

> Therefore, we find that PEF has offered a fully vetted, transparent, and convincing discussion of the reasonableness of continuing the LNP compared to cancellation at this time. We find that PEF's decision to continue pursuing a COL for the LNP reasonable. We do not find that the record supports adoption of the risk sharing mechanism as proposed by OPC. Our findings affords PEF the opportunity to continue forward with the LNP in an effort to secure the expected long-term benefits and also allows the opportunity to assess the appropriateness of any LNP specific risk sharing mechanism in a subsequent proceeding.

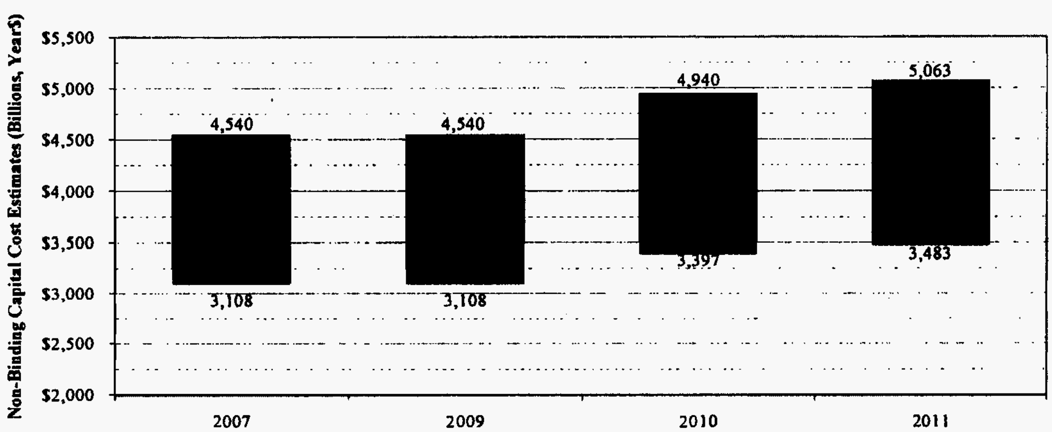
We draw guidance from this Order, and based on a preponderance of the record, find that FPL has demonstrated its consideration of the risks and benefits in deciding to continue forward with the TP67 project compared to cancellation at this time. Therefore, we find that FPL's continued pursuit of the TP67 COL was reasonable because it affords FPL the opportunity to continue forward with the TP67 project, which is consistent with our finding above.

V. Current Total Estimated All-inclusive Cost (Including AFUDC and Sunk Costs) of the Proposed Turkey Point Units 6 & 7 Nuclear Project

FIPUG took the position that FPL's cost estimate was "subject to continued escalation and the actual price is not known." No evidence was offered to demonstrate that actual prices should be known at this time.

FPL's current non-binding estimated range of capital cost is $3,483 to $5,063 per kilowatt in overnight costs. This represents an 11.5 percent increase from FPL's estimated maximum cost in the 2007 need determination proceeding and a 12.1 percent increase in the minimum cost. The history of cost estimates is shown in the table below.

Range of Non-Binding Capital Cost Estimates ($/kW)



As discussed above, other intervenors did not contest FPL's estimated cost. No evidence was presented to refute or change FPL's estimate. FPL used its updated project cost estimate in conducting its cost-effectiveness analysis above. Results of the analysis demonstrate that the cost-effectiveness of the project has declined in comparison with the competing plan without nuclear generation. We find that FPL's cost estimate is reasonable.

VI. Current Estimated Planned Commercial Operation Date of the Planned Turkey Point Units 6 & 7 Nuclear Facility

FIPUG argued that FPL's estimated commercial operations dates were subject to revision and are uncertain. However, FIPUG offered no evidence with which to support its argument. Other intervenors did not dispute FPL's estimated commercial operations dates.

FPL witness Scroggs testified that an early 2010 review of the project schedule indicated that pre-construction activity and licensing activity should not run in parallel. FPL then rescheduled pre-construction activity to occur after licensing, which shifted commercial operations dates to 2022 and 2023 for TP67, respectively.

We note that FPL has used the 2022/2023 dates in its annual feasibility analyses for 2010 and 2011, as previously discussed above. Therefore, we find that FPL's estimated commercial operations dates are 2022 and 2023 for TP 6 and 7, respectively.

VII. Prudence of 2009-2010 TP67 Project Management

This issue addresses project management, contracting, accounting and oversight controls employed by FPL during 2009 and 2010 for the TP67 project. Examples of project management oversight controls are having stated corporate policies for developing project schedules, developing annual budgets, tracking variances, training on these policies, and verifying that the team members adhere to corporate policies.

No specific concerns or deficiencies were identified by the parties or audit staff witnesses. Audit staff witness Welch identified that recovery of 2010 lobbyist registration expenses was being requested through the NCRC, and questioned the appropriateness of recovery. The exclusion of lobbyist registration expenses from the NCRC would reduce FPL's incurred jurisdictional amounts and NCRC recovery amounts by $3,389 and $3,807, for TP 6 and 7 respectively, as discussed below. SACE's position on this issue to find FPL's project management imprudent relied on arguments it raised above regarding FPL's intent to complete the project and the feasibility of completing the TP67 project.

A. FPL's 2009-2010 TP67 Project Management and Related Controls

In 2009, FPL management deferred the EPC contract and long lead material procurement. FPL's 2009 activities focused on finalizing licenses and permit applications. FPL management made the following key decisions during 2010: 1) revised the project schedule to decouple licensing and preconstruction activities which resulted in new in-service dates of 2022 and 2023; 2) reviewed the project cost estimate range to determine if the range remained achievable; 3) extended the Forging Reservation Agreement into March of 2011; 4) executed the Joint Participation for reclaimed water; and 5) continued pursuit of a radial collector well system as a backup cooling water supply for the project. FPL witness Scroggs opined that the most important near term activity is obtaining the licenses and approvals necessary to construct and operate TP67. He opined that based on FPL's review, key project issues had not matured to the stage that warranted pursuing pre-construction activities in parallel with licensing activities.

When questioned by FIPUG regarding whether FPL intended to construct the TP67 units, FPL witness Scroggs said yes. He explained that FPL would not be engaged in the licensing process if FPL did not intend to construct the units. He further explained that it is a question about the appropriate time to initiate construction. SACE inquired whether FPL had made a final decision to construct the units, and FPL witness Scroggs affirmed that FPL had not. He explained that the decision is going to be based on the economics and events as they unfold over the next several years.

FPL retained Concentric Energy Advisors (Concentric) to review FPL's system of internal controls to develop and maintain the option to construct TP67. Testimony regarding Concentric's review was presented by FPL witness Reed, the Chairman and Chief Executive Officer of Concentric. Concentric reviewed the project organizational structures, project milestones, and other documents, and conducted several interviews. Witness Reed asserted that these efforts were to make certain FPL's TP67 policies, procedures and instructions were known by the project team, were being implemented, and resulted in prudent decisions based on the information that was available at the time of each decision.

Based on the review performed, FPL witness Reed opined that FPL had clearly stated corporate policies for developing project schedules and had complied with those procedures. Witness Reed concluded that FPL's TP67 project management practices and procedures were reasonable and met industry norms. He expressed agreement with FPL's revised in-service dates to 2022/2023, in part, because of protracted licensing and permitting schedules. Regarding FPL's budgets, FPL witness Reed concluded that FPL adhered to its corporate procedures. Concentric found that FPL's TP67 project team acted prudently when developing the annual budget and tracking budget performance. He stated that there were no project management deficiencies that led to imprudently incurred costs during the review periods.

FPL retained witness Diaz with ND2 Group, a consulting firm, to provide a summary of the NRC's role in licensing FPL's TP67 project, and to discuss FPL's licensing decisions. He presented an overview of the NRC's role and responsibilities, and an overview of 10 CFR Part 52, that sets forth the new reactor licensing framework. He described the status of NRC's review of FPL's TP67 COL application as ongoing with expected completion in 2013. He opined that the 1992 Energy Policy Act implied three strategies to minimize financial and regulatory risk: 1) licensing decisions would be finalized before major construction begins; 2) utilities would order assets after regulatory/financial risks are mitigated by satisfactory COL progress; and 3) limited site work could begin prior to COL issuance. Witness Diaz went on to say he believed FPL's project management decisions have been consistent with these strategies. He concluded that FPL's approach to managing the project is prudent and reasonable.

OPC witness Jacobs reviewed the status of the TP67 project and FPL's project management. He stated he was not "taking issue with FPL's approach to the Turkey Point 6 and 7 projects at this time."

Audit staff witnesses Fisher and Rich reviewed FPL's 2009 and 2010 project management controls. The primary objective of their annual review was to document project key developments, along with the organization, management, internal controls, and oversight that FPL had in place. The internal controls examined were related to planning, management and organization, costs and schedule, contractor selection and management, auditing, and quality assurance. Witnesses Fisher and Rich made no specific recommendations. They believe that we should continue to closely monitor all new nuclear project controls, costs, activities, and schedule as the TP67 project transitions from licensing to site preparation and construction.

B. FPL's 2009-2010 TP67 Accounting and Related Controls

FPL's TP67 accounting and related controls were generally described by FPL witness Powers. Witness Powers asserted that FPL's controls were documented, assessed, audited, and tested on a going forward basis by both FPL's internal and external auditors, as well as our audit staff. Witness Powers stated that the 2009 and 2010 costs and controls will have been audited prior to the start of the hearing. Regarding internal audits, FPL witness Reed stated "[i]n 2010, PTN 6 & 7 received an audit rating of "Good," the highest rating used by Internal Audit." The 2009 and 2010 internal audits were presented to the TP67 project team in November 2009 and May 2010, respectively. Witness Powers asserted these audits will continue to provide assurance that the internal controls surrounding transactions and processes are well-established, maintained and communicated to employees, and provide additional assurance that the financial and operating information generated within FPL is accurate and reliable.

Audit staff witness Welch tested FPL's accounting and related controls. Witness Welch presented one finding related to lobbying expenses. She stated:

> It has been Commission practice to disallow cost for direct lobbying or in support of direct lobbying activities. This Commission has maintained that costs of such activities should be borne by the stockholder since there is no evidence that the ratepayers receive any benefits from these expenditures.

Regarding these lobbying expenses, FPL witness Powers responded:

> The County Ethics Ordinance defines lobbying very broadly to include "all persons . . . who seeks to encourage the passage . . . of . . . any action, decision, recommendation of the County Manager or any County board or committee . . . or recommendation of County personnel during the time period of the entire decision-making process . . .". There are a number of project team members that must routinely meet with personnel of Miami-Dade County regarding the project. As such, it would be impossible for these project team members to interact with County staff on the project without potentially implicating this broad definition of "lobbying".
>
> While FPL does not believe these registration fees are lobbying costs, FPL removed the costs from the Turkey Point 6 & 7 project in May 2011. The accounting entry to reflect this adjustment was provided to the Audit Staff.

C. Prudence Standard

Our standard for determining prudence is well documented in our past Orders. That standard is ". . . what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should been known, at the time the decision was made." (Order No. PSC-08-0749-FOF-EI, p. 28) We reaffirmed this prudence standard in Order No. PSC-09-0783-FOF-EI:

> The applicable standard for determining prudence is consideration of what a reasonable utility manager would have done in light of conditions and circumstances which were known or reasonably should have been known at the time decisions were made.

Based on the foregoing, we find that FPL's TP67 project management and accounting and related controls were subjected to a reasonable level of review sufficient to determine prudence. We find that there is no record evidence identifying any FPL TP67 project management decisions or accounting as unneeded or unreasonable. We also note that, at this time, no party identified unreasonable or imprudent TP67 project management actions. We note that the only program management-related activities disputed as recoverable were lobbyist registration fees that FPL subsequently agreed to remove from the NCRC. Consequently, we find that the project management, contracting, accounting and cost oversight controls employed by FPL during 2009 and 2010 for the TP67 project were reasonable and prudent.

VIII. System and Jurisdictional Amounts Approved as FPL's Final 2009 and 2010 Prudently Incurred Costs and Final True-up Amounts for the Turkey Point Units 6 & 7 Project

This issue addresses FPL's request concerning the prudence of its 2009 and 2010 TP67 incurred costs and the final true-up of amounts for 2009 and 2010. SACE's urged us to deny recovery based on its arguments stated above regarding FPL's intent to complete the project and the feasibility of completing the TP67 project which we have already addressed. Consistent with our findings above, we made adjustments to exclude lobbying expenses. No other concerns were raised.

FPL witness Powers provided support for the 2009 and 2010 TP67 project costs and methods used to determine the requested final true-up recovery amount. FPL witness Scroggs provided descriptions of the 2009 and 2010 TP67 project activities, costs, and variances.

A. 2009 Incurred Costs and Final True-up Amount

Witnesses Powers and Scroggs identified that the 2009 TP67 preconstruction capital costs were $37,731,525 ($37,599,045 jurisdictional). They also indicated that carrying costs incurred during 2009 were $857,693. Both witnesses Powers and Scroggs identified additional carrying costs of $373,162 for site selection costs. FPL requested that we review and approve these amounts as prudent and recoverable. In support of FPL's request, FPL witness Scroggs stated:

> During 2009, the project completed the studies and analyses supporting applications to federal, state and local entities for required licenses, certifications and permits to construct and operate the project. These applications describe the project's technical and environmental aspects and are now the focus of extensive agency review and deliberation that will continue through the next several years. Additionally, 2009 was a year of negotiation, analysis and review to determine how and when to take additional steps beyond the licensing activity in preparation for project construction.

FPL's year-ending 2009 incurred costs were $7,909,137 less than its May 2009 estimate of $37,731,525. FPL spent $5,164,519 less for licensing costs, primarily because of lower-than-planned NRC fees, Bechtel COLA contract support, transmission line permitting, and unused contingency. Project permitting costs were $960,060 lower than estimated due in part to a change in the application filing dates shifting planned support costs into 2010, reclassification of certain 2008 and 2009 legal expenses, and unused contingency. Engineering and design costs were $1,786,327 lower than planned due in part to deferrals, reduced construction team, and reduced scope of 2009 contracted activities. FPL incurred an unfavorable variance of $1,769 in legal support costs for its reclaimed water activities.

Witness Powers explained that the year-ending 2009 project costs were compared to our prior approved and recovered amounts to determine the net final true-up amount for 2009 of negative $10,648,277. The requested 2009 net final true-up amount includes the following items: over-projected capital costs in the amount of $7,845,423 and $2,802,854 in over-projected carrying costs. FPL did not request that these amounts be used in determining the 2012 total NCRC recovery amount because the amounts were already included in FPL's 2011 CCRC.

<u>B. 2010 Incurred Costs and Final True-up Amount</u>

Witnesses Powers and Scroggs indicated that the 2010 incurred costs for TP67 project capital costs were $25,593,577 ($25,291,109 jurisdictional). They also indicated that carrying costs incurred during 2010 were negative $5,849,900. Witnesses Powers and Scroggs identified additional carrying costs on site selection of $145,965. FPL requested that we review and approve these amounts as prudent and recoverable. In support of its request, FPL witness Scroggs stated:

> Primarily, FPL maintained progress on the review of license and permit applications and other activities initiated in 2009. The project completed a combined schedule and cost estimate review of the project in the early part of the year resulting in a change to the estimated operational dates for the project.

FPL's year-ending 2010 incurred costs were $17,036,078 less than its May 2010 estimate of $42,629,655. FPL spent $11,148,208 less in licensing costs primarily because of lower than planned NRC fees, Bechtel COLA contract support, project staffing, Environmental Services support, external legal services, and unused contingency. Project permitting costs were $2,004,977 lower than estimated due to reduced communications expenses and unused contingency. Engineering and design costs were $3,882,893 lower than planned due in part to a delay in starting an exploratory well.

Witness Powers explained that these 2010 project costs were compared to the prior estimate for 2010 to determine the net final true-up amount for 2010 of negative $17,949,858. The requested 2010 net final true-up amount includes the following items: over-projected capital costs of $16,834,744 and over-projected carrying costs of $1,115,115. FPL is requesting that these amounts be used in determining the 2012 total NCRC recovery amount. We note that witness Powers did not contest the calculation of adjustments identified by our audit staff witness Welch.

C. Prudence Standard

As previously discussed above, the standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should been known, at the time the decision was made. (Order No. PSC-08-0749-FOF-EI, p. 28) We note that beyond the lobbyist registration expense item discussed above, no other concerns were identified regarding the reasonableness or prudence of FPL's 2009 and 2010 incurred costs.

As noted above, audit staff witness Welch raised a concern regarding the potential recovery of lobbying expenses incurred in 2010. Witness Welch testified:

> It has been Commission practice to disallow cost for direct lobbying or in support of direct lobbying activities. This Commission has maintained that costs of such activities should be borne by the stockholder since there is no evidence that the ratepayers receive any benefits from these expenditures.
>
> During the testing of Pre-construction expenditures, we found two entries for lobbyist registration fees for seven Company employees totaling $3,430 ($490 per lobbyist x 7 Company employees). The invoices are titled "Miami-Dade County 2010 Lobbyist Registration." If the Commission disallows the cost stated above, Pre-Construction cost, Carrying Cost on Pre-Construction Cost, and Deferred Carrying Cost would be reduced by $3,389, $292, and $126, respectively.

Regarding the identified expenses, FPL rebuttal witness Powers stated:

> FPL therefore determined that it would be prudent to register these individuals to ensure compliance with the local ordinance and to protect against a claim of "lobbying" without registration.
>
> While FPL does not believe these registration fees are lobbying costs, FPL removed the costs from the Turkey Point 6 & 7 project in May 2011. The accounting entry to reflect this adjustment was provided to the Audit Staff.

> The Company recommends that the adjustment should be reflected in FPL's 2011 Preconstruction True-up Nuclear Filing Requirement (NFR) schedule which will be filed March 1, 2012.

We find that FPL's May 2011 actions to remove the expense were consistent with our practice of disallowing recovery of lobbyist registration expenses. Consequently, there is no need for us to determine the prudence of lobbying registration costs identified by witness Welch, and the 2010 prudently incurred amounts shall exclude the amounts identified by witness Welch. The adjustments to FPL's 2010 expenditures were \$3,430 (\$3,389 jurisdictional) and \$418 in associated carrying costs (\$292 + \$126 = \$418). These adjustments reduce FPL's 2010 incurred costs as follows: system capital costs in the amount of \$25,590,147 (\$25,593,577 - \$3,430 = \$25,590,147), jurisdictional capital costs of \$25,287,720 (\$25,291,109 - \$3,389 = \$25,287,720), and carrying costs of negative \$1,115,533 (-\$1,115,115 -\$418 = -\$1,115,533). These adjustments shall change FPL's net final true-up amount for 2010 to negative \$17,953,665 (-\$17,949,858 - \$3,389 - \$418 = -\$17,953,665).

We note that beyond the lobbyist registration expense item, no other concerns were identified regarding the reasonableness or prudence of FPL's 2009 and 2010 incurred costs. Consistent with our findings above, our verification of FPL's calculations and true-up amount, and a preponderance of the evidence in the record, we find that FPL has demonstrated the prudence of its requested 2009 and 2010 incurred costs and final true-up amounts for the TP67 project, net of the 2010 lobbyist registration expenses. Therefore, we approve as prudently incurred TP67 project Capital Costs of \$37,731,525 (\$37,599,045 jurisdictional). The final 2009 NCRC true-up amount, net of prior recoveries, is negative \$10,648,277 and will be fully refunded during 2011. No further action is required regarding FPL's 2009 incurred costs. For 2010, we approve as prudently incurred TP67 project Capital Costs of \$25,590,147 (\$25,287,720 jurisdictional). The final 2010 NCRC true-up amount, net of prior recoveries, is negative \$17,953,665 and shall be used in determining the 2012 NCRC recovery amount.

<u>IX. 2011 System and Jurisdictional Amounts Approved as Reasonably Estimated Costs and Estimated True-up Amounts for FPL's Turkey Point Units 6 & 7 Project</u>

This issue addresses FPL's request concerning the reasonableness of its 2011 TP67 estimated costs and the estimated true-up amount for 2011. SACE's again urged us to deny all recovery stems from arguments it raised regarding FPL's intent to complete the project and the feasibility of completing the TP67 project. No testimony by parties or the staff audit witnesses proposed adjustments to FPL's 2011 estimates. We note that resolution of this issue must be consistent with the resolution of forward-looking issues addressing project feasibility and also prospective implementation of any prudence determinations.

FPL witness Powers provided support for the 2011 TP67 project costs and methods used to determine the requested estimated true-up recovery amount. FPL witness Scroggs provided descriptions of the 2011 TP67 project activities, costs, and variances.

Witnesses Powers and Scroggs identified 2011 TP67 preconstruction capital costs of \$37,955,536 (\$37,506,973 jurisdictional). They also indicated that the estimated 2011 preconstruction carrying costs were negative \$812,681. Witnesses Powers and Scroggs identified additional carrying costs on site selection costs of \$171,052 due to tax effects on FPL's previously recovered site selection costs. In support of FPL's request, FPL witness Scroggs stated:

> The primary focus of the current phase of the project has been, and remains, obtaining the necessary federal, state and local approvals that will define the project and enable construction and operation of the Turkey Point 6 & 7 project. In doing so FPL is creating a valuable option that can be exercised at the most opportune time for the benefit of FPL customers.

Witness Scroggs also presented a graphic of the current deployment schedule for various phases of the TP67 project from 2006 through 2023. The graphic showed that during 2011, FPL was engaged in the licensing phase, and site-specific construction may begin in 2016.

FPL's estimate of year-ending 2011 incurred costs was \$37,955,536. The 2011 cost estimate included amounts for licensing of \$28,789,986, permitting of \$2,416,877, and engineering and design of \$6,748,673. The estimated 2011 costs for long-lead procurement, power block engineering and procurement, and transmission activities were zero.

The estimated 2011 costs are \$8,486,061 greater than FPL's May 2010 projection of its 2011 costs. FPL attributed the increase to shifts in the timing of activities. Licensing costs increased by \$6,416,607, permitting costs increased by \$40,785, and engineering and design costs increased by \$2,028,669. No party identified any specific amount of FPL's 2011 TP67 project cost estimates as unreasonable or unnecessary to complete the TP67 project.

Witness Powers explained that the estimated 2011 project costs were then compared to the projection of 2011 costs to determine the estimated true-up amount for 2011 of \$5,383,897. The requested 2011 true-up amount includes under-projected preconstruction capital costs of \$8,385,772 and a \$3,001,875 over-projection of preconstruction carrying costs. No additional site selection costs will be incurred in the future and there is no related true-up of 2011 site selection costs to be included in the net total NCRC recovery amount. These 2011 estimated true-up amounts were included in FPL's net total NCRC recovery request of \$196,092,631.

As noted above, audit staff witness Welch raised a concern regarding recovery of lobbyist registration expenses incurred in 2010. Consistent with our findings above, we find that FPL shall remove any 2011 lobbyist registration fees from NCRC recovery amounts. We note that FPL's estimated 2011 expenses cannot be audited at this time. Additionally, the adjustment recommended by witness Welch, and unopposed by FPL, only addresses the 2010 period and did not include ongoing true-up impacts through 2011. As previously addressed above, FPL has made accounting entries that will ultimately refund amounts FPL already collected on a projected basis. FPL shall incur carrying charges until the full amount is refunded. The carrying charge rate is 7.42 percent on a pre-tax basis. We note the adjustment is small and recognition of that amount in setting the 2012 CCRC factors is not expected to decrease customer bills.

Therefore, we find that allowing FPL to reflect the effect of the 2010 adjustment on FPL's estimated 2011 true-up amounts in its 2012 filings is reasonable and efficient.

We note that beyond the lobbyist registration expense item, no other concerns were identified that would impact FPL's estimated 2011 incurred costs and estimated true-up amounts for the TP67 project. Consistent with our findings above, our verification of FPL's calculations and true-up amount, and a preponderance of the evidence in the record, we find that FPL has demonstrated the reasonableness of its requested estimate of 2011 incurred costs and true-up amounts for the TP67 project. Therefore, we approve as reasonable estimated 2011 TP67 project Capital Costs of $37,955,536 ($37,506,973 jurisdictional). The estimated 2011 true-up amount of $5,383,897, net of prior recoveries, shall be used in determining the net total 2012 NCRC recovery amount.

X. 2012 System and Jurisdictional Amounts Approved as Reasonably Projected Costs for FPL's Turkey Point Units 6 & 7 Project

This issue addresses FPL's request concerning the reasonableness of its 2012 TP67 projected costs and the projected NCRC recovery amount. SACE's asserted that no costs should be recovered based on its arguments regarding FPL's intent to complete the project and the feasibility of completing the TP67 project. No testimony by parties or audit staff witnesses proposed adjustments. We note that resolution of this issue must be consistent with the resolution of forward-looking issues discussed above, project feasibility, and also prospective implementation of any prudence determinations.

FPL witness Powers provided support for the 2012 TP67 project costs and methods used to determine the requested recovery amount. FPL witness Scroggs provided descriptions of the 2012 TP67 project activities and costs.

Witnesses Powers and Scroggs identified the 2012 TP67 preconstruction capital costs of $31,393,088 ($31,022,080 jurisdictional). They also indicated that the projected 2012 preconstruction carrying costs were $5,620,298. Witnesses Powers and Scroggs identified additional carrying costs on site selection costs of $180,883 due to tax effects on FPL's previously recovered site selection costs. In support of FPL's request, FPL witness Scroggs stated:

> Procurement activities in 2011 and 2012 generally focus on the licensing and permitting process required to support and advance the federal, state and local approval processes. Professional services will be required from technical and environmental consultants, legal service firms and subject matter experts to respond to the inquiries of the public and the reviewing agencies during the application review process or the subsequent hearings. Additionally, the current project schedule calls for Preparation phase activities, such as clearing and grading at the site, in mid-2013. In order to prepare for those activities FPL would need to hire additional staff for its Construction team, conduct engineering reviews and planning, and develop bid packages for the work in 2012. FPL has not included these costs in the projected 2012 request based on the need to

> observe significant events in 2011 and early 2012 prior to authorizing such expenditures. As more information is developed in 2011 and 2012, FPL will make a decision to move forward on the current schedule or make appropriate revisions.

Witness Scroggs also presented a graphic of the current deployment schedule for various phases of the TP67 project from 2006 through 2023. The graphic showed that during 2012, FPL plans to be engaged in the licensing phase, and site specific construction may begin in 2016.

FPL's projected 2012 costs total $31,393,088. The 2012 cost projection included amounts for licensing of $27,362,894, permitting of $2,420,144, and engineering and design of $1,610,050. The projected 2012 costs for long-lead procurement, power block engineering and procurement, and transmission activities were zero. No party identified any amount of FPL's 2012 TP67 project cost estimates as unreasonable or unnecessary to complete the TP67 project.

FPL's requested NCRC amount for 2012 TP67 project costs was $36,823,261. This amount includes the following items that have been previously discussed above: pre-construction capital costs in the amount of $31,022,080, associated carrying charges of $5,620,298, and $180,883 in carrying charges on prior years' unrecovered site selection costs. FPL included these 2012 amounts in its net total NCRC recovery request of $196,092,631.

As noted above, audit staff witness Welch raised a concern regarding recovery of lobbyist registration expenses incurred in 2010. Consistent with our findings above regarding FPL's estimated 2011 recovery amounts, we find that FPL shall remove any 2012 lobbyist registration fees from NCRC recovery amounts. We note that FPL's projected 2012 expenses cannot be audited at this time. Additionally, the adjustment recommended by witness Welch and unopposed by FPL only addressed the 2010 period and did not include ongoing true-up impacts through 2012. As addressed above, FPL has agreed to remove the charges and refund amounts FPL already collected on a projected basis. FPL shall incur carrying charges until the full amount is refunded. The carrying charge rate is 7.42 percent on a pre-tax basis. We note the adjustment is small and recognition of that amount in setting the 2012 CCRC factors is not expected to decrease customer bills. Therefore, we find that allowing FPL to reflect the effect of the 2010 adjustment in its 2012 filings is reasonable and efficient.

We note that other than the lobbyist registration expense item, no other concerns were identified that would impact FPL's projected 2012 TP67 project costs. Consistent with our findings above, our verification of FPL's calculations, and a preponderance of the evidence in the record, we find that FPL has demonstrated the reasonableness of its requested projection of 2012 incurred costs and recovery amounts for the TP67 project. Therefore, we approve as reasonable projected 2012 TP67 project Capital Costs of $31,393,088 ($31,022,080 jurisdictional). The projected 2012 amount of $36,823,261 shall be used in determining the net NCRC recovery amount.

XI. 2010 and 2011 Annual Detailed Analyses of the Long-term Feasibility of Completing the EPU Project

This issue addresses review and approval of FPL's detailed long-term feasibility analysis of continuing construction and completing the EPU project as required by Rule 25-6.0423, F.A.C. Additionally, this issue also addresses concerns raised by OPC and supported by SACE and FIPUG, relating to increased capital cost estimates, the treatment of sunk costs, the need to perform a breakeven analysis, and the need for separate economic analyses of the St. Lucie and Turkey Point plants.

In an effort to mitigate the economic risks associated with the long lead-time and high capital costs associated with nuclear power plants, the Florida Legislature enacted Sections 366.93 and 403.519(4), F.S., during the 2006 legislative session. Section 366.93(2), F.S., requires us to establish, by rule, alternative cost recovery mechanisms for the recovery of costs incurred in the siting, design, licensing, and construction of a nuclear power plant. We adopted Rule 25-6.0423, F.A.C., to satisfy the requirements of Section 366.93(2), F.S. Rule 25-6.0423(5)(c)5, F.A.C., states:

> By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long term feasibility of completing the power plant.

The annual feasibility review gives us an opportunity to consider FPL's trends for the EPU project and evaluate whether the EPU project is feasible to continue.

A. Long-Term Feasibility Analysis of the EPU Project

FPL witness Sim presented the long-term feasibility analysis. The analysis included updated forecasts for fuel costs, environmental compliance costs, customer load, and capital costs. Each of these components will be discussed below. From these forecasts, an economic analysis was performed. We also analyzed regulatory and technical factors that may influence the feasibility of project completion.

1. Project Cost-Effectiveness

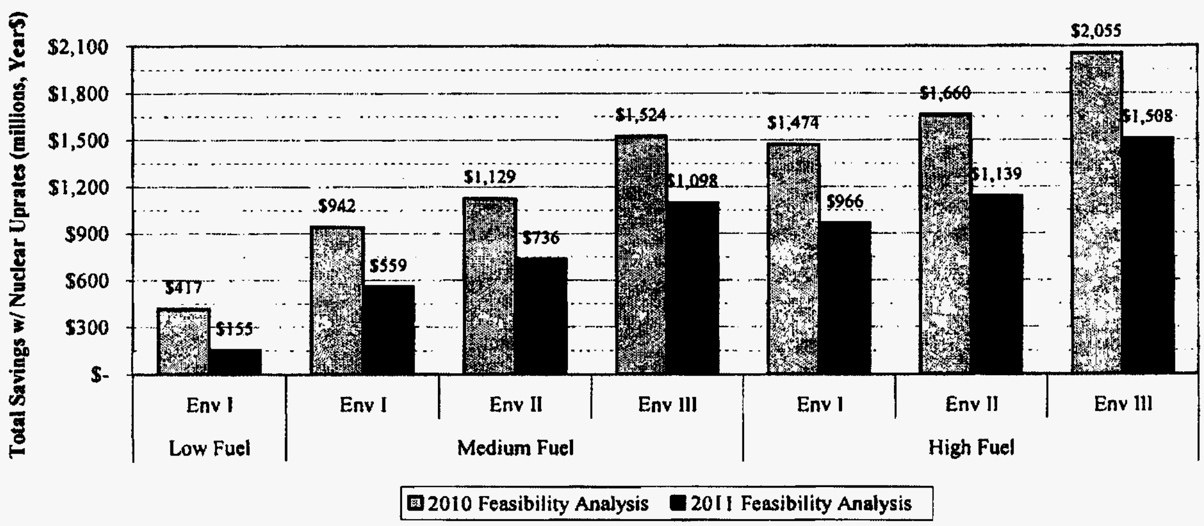
The cost-effectiveness analysis presented here is the sum of all the assumptions utilized by FPL in producing its long-term feasibility, and represents FPL's quantitative assessment that continuation of the EPU project is economically feasible. FPL witness Sim performed a cost-effectiveness analysis based on Cumulative Present Value Revenue Requirements (CPVRR), which compared a resource plan featuring the EPU project with an alternate resource plan that did not feature the nuclear uprates. Witness Sim described the undertaking of developing the CPVRR of each resource plan:

> The analysis of each resource plan is a complex undertaking. For each resource plan, annual projections of system fuel costs and emission profiles, for each scenario of fuel cost/environmental compliance cost, are developed using a

sophisticated production costing model. This model, the P-MArea model, simulates the FPL system and dispatches all of the generating units on an hour-by-hour basis for each year in the analysis. The resulting fuel cost and emission profile information is then combined with projected annual capital, operation and maintenance (O&M), etc. costs for each resource plan. In this way, a comprehensive set of projected annual costs, for each year of the analysis, is developed for each resource plan.

As noted above, sensitivities on fuel costs and environmental compliance costs were conducted, resulting ultimately in seven combined scenarios evaluated for cost-effectiveness. In all of these scenarios, the EPU project is more cost-effective than the alternative generating portfolio. The results of the CPVRR Analysis are shown below for each of the seven sensitivities, and are compared to the 2010 feasibility analysis. Overall, there has been a significant decline in the cost-effectiveness in all scenarios when compared to the 2010 feasibility analysis, as detailed below.

CPVRR Analysis Results - Estimated NPV of Total Savings from EPU Project



The CPVRR analysis performed for the 2011 long-term feasibility analysis was similar to the methodology employed for the EPU project performed for the 2007 Determination of Need filing, and the 2008, 2009, and 2010 NCRC filings. FPL witness Sim testified that all the major assumptions were updated in this most recent estimate of cost-effectiveness for the EPU project. These include fuel, environmental, load, and capital cost forecasts. These forecasts are discussed in more detail below.

The CPVRR analysis excluded previously spent capital costs, also termed sunk costs. OPC, supported by SACE and FIPUG, raised concerns about the exclusion of sunk costs and its potential to skew a CPVRR analysis of cost-effectiveness. Further, OPC, supported by SACE and FIPUG, recommend usage of an alternate economic analysis, a breakeven calculation. These concerns are discussed in detail below.

2. Updated Fuel & Environmental Forecasts

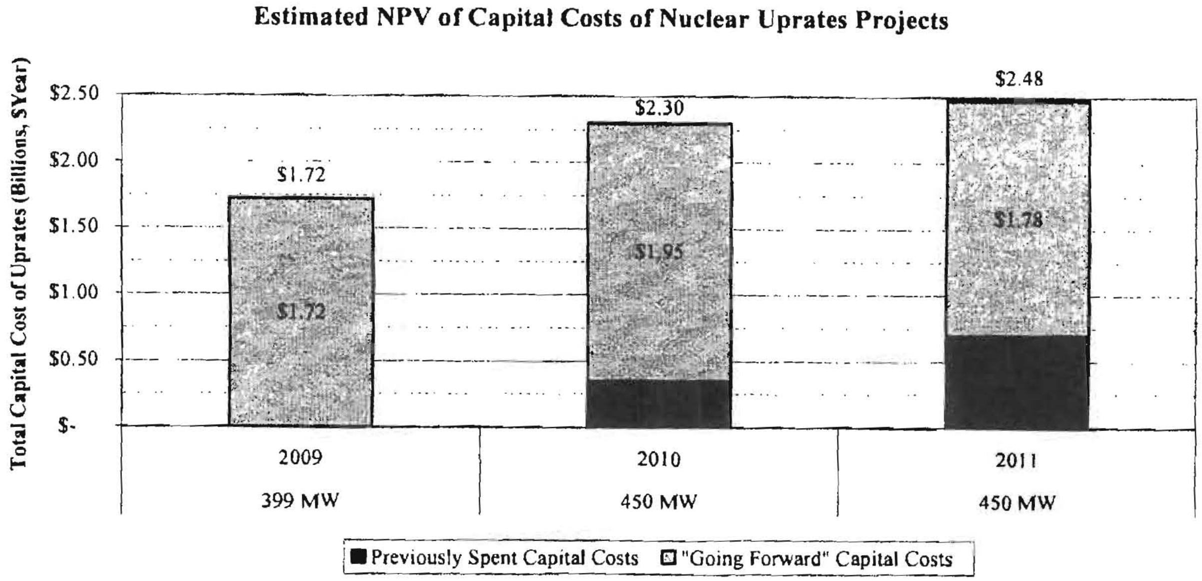
FPL submitted updated fuel cost and environmental compliance cost forecasts as part of its long-term feasibility analysis for the EPU project. FPL witness Sim noted that these forecasts are identical for the EPU project and the TP67 analysis. As discussed above, FPL witness Scroggs stated that natural gas prices and the cost of carbon were influential drivers to the overall cost-effectiveness, and that there was currently no price on carbon.

3. Updated Load Forecasts & Reserve Margin Projection

FPL submitted updated load forecasts and a resource plan for reserve margin requirements as part of its long-term feasibility analysis for the EPU project. FPL's updated load forecast projected that FPL would retain a sufficient reserve margin without the EPU project until 2016. FPL's updated resource plan with the EPU and the alternate resource plan include a greenfield 3x1 combined cycle unit in 2016. While the EPU project was shown to have no effect on accelerating the need for the next avoidable unit, the alternate resource plan requires construction of a second greenfield 3x1 combined cycle to be accelerated by two years, resulting in a 2018 in-service date, compared to the resource plan with the EPU project.

4. Updated Capital Costs

FPL witness Sim provided updated non-binding capital cost figures, including previously spent capital costs and "going forward" capital costs. Overall, the total cost of the Project has increased to $2.48 billion in the 2011 feasibility analysis, up from $2.30 billion from the 2010 feasibility analysis. These non-binding capital costs estimates, as well as the portions previously spent or remaining to be spent, are detailed below, along with the estimated incremental capacity to be added by the EPU project.



Concerns were raised by OPC and FIPUG that there was uncertainty in the capital costs of the EPU project, and that capital cost increases may be hidden by expenditures. Both OPC witnesses Smith and Jacobs noted that the total capital cost estimates have increased during each feasibility analysis. We agree that on a year-to-year basis, the project has increased its total capital cost, but note that the estimated capacity output of the EPU project has also increased since 2009, as detailed above.

OPC argued that if FPL had used a more "realistic estimate of capital costs" in its original analysis, the EPU project might have been shown to be prohibitively expensive. OPC witness Jacob further suggested that the estimate for going-forward capital costs "can only be an uneducated guess" as engineering work had not been fully completed.

FPL witness Jones disagreed with OPC witness Jacob's assertion, and stated that FPL's current capital cost estimate was more defined than in previous years' feasibility analysis, and refers to it as "highly informed." FPL witness Sim noted that within a year, two of the uprate projects will have been completed, and the third near completion. A timeline of the implementation outages is provided below. It should be noted that a partial uprate has already been completed on St. Lucie Unit 2, resulting in 29 MW of the total capacity increase listed below.

EPU Project Outage Schedule

Unit	Implementation	Outage Duration (Days)	Capacity Increase (MW)
St. Lucie Unit 1	November 26, 2011	110	122
St. Lucie Unit 2	June 27, 2012	95	110
Turkey Point Unit 3	February 6, 2012	120	109
Turkey Point Unit 4	October 1, 2012	120	109

Due to the year-to-year increase in total capital costs for the EPU project, OPC and FIPUG raised concerns that the impact of higher capital costs was being masked by FPL's treatment of sunk costs, and that an alternate economic analysis methodology is required. Further, they suggested that the individual plant sites for the EPU project (St. Lucie and Turkey Point) should be evaluated separately for economic benefits. These topics are discussed below.

5. Treatment of Sunk Costs

In Order 08-0237-FOF-EI, we required as part of FPL's long-term feasibility filings that "... FPL should account for sunk costs." FPL has provided these previously spent costs as part of its filing. These funds are excluded in the CPVRR analysis described above. We note that sunk costs have increased 100 percent, from $350 million in 2010 to $700 million in 2011. By comparison, total project cost increased only 7.8 percent, from $2.3 billion in 2010 to $2.48 billion in 2011.

Both OPC and FIPUG raised concerns that by not including these costs, the cost-effectiveness analysis was skewed in favor of the EPU project in the event of capital cost increases. FPL witnesses Sim and Reed and OPC witnesses Jacobs and Smith agreed that excluding sunk costs is widely accepted in evaluations of project cost-effectiveness. However, witnesses Jacobs and Smith stated that the increased capital costs associated with the EPU project made it inappropriate for the EPU project. OPC witness Jacobs stated that:

> If the estimated total cost is increased at a rate that approximates the expenditures on the project, the cost to complete will be unchanged while the total project cost is rapidly increasing. This masks the true picture of whether the project is economically feasible.

OPC witness Smith suggested that sunk costs may not be fully recoverable in the alternative portfolio. Witness Smith further proposed an alternative economic analysis, in which sunk costs were added to the EPU resource portfolio in the CPVRR analysis, but not the alternate non-EPU resource portfolio. This resulted in a net reduction of the CPVRR benefits by the amount of sunk costs. Witness Smith asserted that in some fuel and environmental scenarios that the EPU project showed negative cost-effectiveness. FIPUG agreed, and stated that this form of analysis showed the EPU project represented a net cost to customers.

Both FPL witnesses Reed and Sim asserted that inclusion of sunk costs violated traditional economic principles. FPL witness Sim stated that the exclusion of sunk costs should not be based on any condition, including potential changes in capital costs. FPL witness Reed asserted that OPC witness Smith's analysis method was faulty, and that sunk costs, if included, would be equal in both resource plans and result in a net zero impact. We agree. Sunk costs, by definition, would exist regardless of the continuation or cancellation of the EPU project. In adding sunk costs to only one side of a CPVRR analysis, witness Smith engaged in hindsight review. We note that the feasibility analysis is meant to determine whether the EPU projects should be continued or canceled. The feasibility analysis does not address the issue of whether or not a different path, starting at some point in the past, would have resulted in a better outcome. Without the ability to make changes to the past, such analysis is not fruitful and does not provide us with information to address our charge of determining whether the EPU project should be continued.

FPL witness Reed further noted that we already decided on the prudence of expenditures for 2007 and 2008. We note that the prudence of expenditures for 2009 and 2010 is addressed below.

Both FPL witnesses Reed and Sim emphasized that the long-term feasibility analysis was focused on the completion of the EPU project, not its total costs. Both witnesses referred to Rule 25-6.0423(5)(c)5, F.A.C., which states:

> By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the power plant.

FPL witness Reed asserted that the long-term feasibility analysis should be used to determine whether to continue or cancel a project, based on forward-looking analysis. FPL witness Sim used an analogy of the choice between remodeling a home versus selecting to purchase a new home. In this analogy, the homeowner is faced with increased costs after selecting remodel, and must now select between continuing to remodel (at added expense) or purchase a new home. Witness Sim suggested that considering sunk costs would lead to an improper decision, as the homeowner only has influence over to-go costs (to either remodel or purchase a new home). OPC argued that should the homeowner be faced with added expenses each year, that so long as those added expenses are less than the cost of the new home, it could lead to a significantly higher total cost to the homeowner. This argument also relates to the discussion of potential increases in capital costs, discussed above. We agree with FPL that the long-term feasibility is primarily meant to analyze the "going forward" costs of the EPU project.

6. Need for Breakeven Economic Analysis

As noted above, the economic analysis of the long-term feasibility of the EPU project was conducted with a CPVRR analysis, in which two resource portfolios are compared, a resource portfolio with the EPU project, and an alternate portfolio without nuclear uprates. OPC and FIPUG raised concerns that this method of analysis, due to the increased capital costs and treatment of sunk costs previously discussed, may be insufficient to provide us with a proper view of the long-term feasibility of the project. OPC witness Jacobs described the CPVRR analysis performed by FPL as ill-suited, due to uncertainties of capital costs at the beginning of the project. Witness Jacobs further opined that CPVRR was appropriate only for evaluating projects with known and stable costs. Witness Jacobs suggested that CPVRR was appropriate for projects such as the West County Energy Center units, which are natural gas-fired combined cycle units, as they have more clearly defined costs than nuclear units.

As an alternative, OPC and FIPUG suggested that we reject the CPVRR analysis, and require FPL to file a breakeven economic analysis for the EPU project. A breakeven analysis would consist of a CPVRR analysis in which the capital costs for the EPU project are set to zero. The resulting difference between resource portfolios is then used to determine the total cost that can be spent on the project, and expressed in terms of dollars per kilowatt installed capacity. OPC witness Jacobs noted that this form of analysis was performed by FPL for its proposed TP67.

In addition to its usage for determining whether the long-term feasibility analysis supports or opposes the continuation of the project, OPC witness Jacobs supported the use of a breakeven analysis to determine the amount of costs to be allowed for the EPU project. This suggestion is discussed in more detail below.

FPL witness Sim agreed with OPC witness Jacobs that there was less certainty for the EPU project when compared to a combined cycle, but witness Sim suggested that the uncertainty was significantly less than new nuclear generation and that a CPVRR analysis is appropriate. FPL witness Sim characterized the requirement of performing a breakeven analysis as 'changing the rules' and described the EPU project as being in the fourth quarter.

FPL witness Reed asserted that a CPVRR analysis and a breakeven analysis use the same approach, which is the difference between two resource plans, and would produce the same recommendation. Both FPL witnesses Reed and Sim noted that a CPVRR analysis was performed in the 2007 Determination of Need, and the NCRC filings for 2008, 2009, and 2010.

OPC argued that the appropriate methodology for economic analysis is not limited to the method utilized in earlier proceedings, such as the determination of need. FIPUG argued that we need not limit ourself to the analysis preferred by a utility. FPL witness Deason stated that "Commission should avail itself of the tools that it thinks are appropriate." We find that we are not limited to a specific form of economic analysis, breakeven or otherwise. We may require any form of analysis we believe would provide insight into the long-term feasibility of completing the EPU project. We have previously addressed this issue with respect to PEF's

Levy project. In Order No. PSC-09-0783-FOF-EI, we stated that an economic analysis is required and that Rule 25-6.0423, F.A.C., does not provide a prescriptive list of requirements.[14]

However, we do not find that a breakeven analysis is necessary at this time for the EPU project. As noted above, the EPU project is scheduled to have completed or begun all four of the uprate outages by the end of 2012. We find that the capital cost estimates provided by FPL are adequate. A breakeven analysis would not provide additional, dispositive information beyond that which is provided in the CPVRR to determine the cost-effectiveness of the project.

7. Need for Separate Economic Analysis by Plant

Both OPC and FIPUG asserted that a separate economic cost-effectiveness analysis should be done for the St. Lucie and Turkey Point plants. OPC witness Jacobs suggested that the EPU project should be broken up into two separate analyses due to the higher estimated capital costs of the Turkey Point plant portion of the EPU project, and the Turkey Point's earlier license expiration dates.

FPL contended that the EPU project was conceived as a single project that encompassed the capacity of all four units, and that for consistency, should continue being analyzed as a single project. FPL witness Reed characterized breaking up the EPU project into two analyses as a fundamental change, and that it could have a negative impact upon financing.

Further, several FPL witnesses suggested that requiring separate feasibility analyses by plant site would be difficult. FPL witness Sim noted that while separate contracts were acquired for the plant sites, contracts were negotiated based on an uprate of all four nuclear units, and therefore they could not be used to determine costs for a single site without somehow excluding this benefit. FPL witness Jones noted that a similar advantage was gained by purchasing multiples of equipment, resulting in cost savings. Witness Jones suggested that by doing multiple units in parallel allowed additional benefits from sharing resources and the ability to apply lessons learned to later units.

We agree with FPL that a separate economic analysis for each of the EPU project plant is unnecessary, and would be difficult to calculate. While a mathematical average of the benefits derived from lessons learned and equipment bulk orders can be developed, it is not known if these would have materialized if only one plant was upgraded. Therefore, completing separate analyses would incorrectly attribute to the individual plants the benefits gained from performing uprates at both plants simultaneously.

B. Conclusion

Therefore, we approve what FPL has submitted for its 2010 and 2011 long-term feasibility analyses of completing the EPU project, as satisfactory for compliance with Rule 25-

[14] See Order No. PSC-09-0783-FOF-EI, issued November 19, 2009, in Docket No. 090009-EI, In re: Nuclear Cost Recovery Clause, page 32.

6.0423, F.A.C. The EPU project is projected to save an estimated $155 million to $1,508 million over the life of the generating units.

XII. Prudence of 2009-2010 EPU Project Management

This issue addresses project management, contracting, accounting and oversight controls employed by FPL during 2009 and 2010 for the EPU project. Concerns regarding FPL's 2009 changes to the EPU management team and 2010 work stoppage costs were raised by audit staff. Additionally, pursuant to our decision at the beginning of the hearing, this issue also addresses concerns raised by OPC and supported by FIPUG and SACE regarding the prudence of FPL's fast track approach and the need for a breakeven analysis to determine the appropriate amount of EPU investment that should be allowed in rate base for rate making purposes. No additional FPL EPU project management concerns or deficiencies were identified by the parties or the audit staff witnesses.

A. FPL's 2009-2010 EPU Project Management and Related Controls

FPL witness Jones presented a summary of FPL's 2009-2010 EPU project management and related controls. The EPU project is being implemented in four overlapping phases: Engineering Analysis, Long Lead Equipment Procurement, Engineering Design Modification, and Implementation.

The Engineering Analysis Phase provides supporting analyses for the NRC License Amendment Request (LAR) filings, including the development and submittal of the LARs, identification and confirmation of major modifications, and refinement of the conceptual scope. The Long Lead Equipment Procurement Phase involves development of purchase specifications, vender evaluation and review, selection of contractors, and refinement of the cost of long lead equipment. The detailed modification packages are prepared during the Engineering Design Modification Phase. These activities provide the basis for further detailed cost and schedule estimates during the Implementation Phase. During the Implementation Phase, the design packages are converted into detailed work orders for actual construction through verification of constructability and scheduling. The Implementation Phase also includes execution of the physical work, testing, and transition to normal operations.

Throughout 2009, FPL was in the Engineering Analysis Phase, approximately midway through the Long Lead Procurement phase, and in the early stages of the Engineering Design Modification and Implementation phases. FPL witness Jones asserted that, in 2009, the project scope was not fully defined and definitive cost estimates were not completed and were not expected to be completed. During 2010, FPL was nearing completion of the Engineering Analysis Phase and progressing in the other phases. Witness Jones asserted that FPL's 2010 non-binding cost estimates reflected the uncertainties of the early stage of the project. FPL quantified the associated project risks based on known information.

Witness Jones asserted that FPL had robust project planning, management, and execution processes in place. He further testified that FPL's personnel were experienced and FPL used guidelines and instructions to assist project personnel in their respective duties.

FPL retained Concentric to evaluate FPL's 2009 system of internal controls used for the EPU project. Concentric's review was presented by FPL witness Reed. The review addressed FPL's estimating and budgeting processes, project schedule development and management, contract management and administration, and internal and external oversight mechanisms. Concentric's work was additive to its prior 2008 and 2009 work. Concentric reviewed FPL's policies, procedures and instructions with emphasis on revisions since the prior review. Concentric's review included organizational structure, key project milestones, other documents, and in-person interviews, to verify that EPU project policies, procedures and instructions were known and implemented by the project teams. FPL witness Reed presented various observations and recommendations directed at improving FPL's processes. He concluded that FPL met major 2009 milestones, including reorganizing project management, changing management personnel, planning outages, executing a ground water monitoring agreement, and progressing on LARs. Other 2009 changes to the EPU project management were to decentralize management, appoint Mr. Terry Jones as Vice President of Nuclear Power Uprates, eliminate the position of Director of EPU projects, create the position of Implementation Owner – South, and change the reporting structure of Project Controls to the director level. Witness Reed stated that since July 2009, nearly all of Concentric's recommendations had been addressed. Witness Reed asserted that FPL's decision to continue pursuing the EPU project in 2009 was prudent and FPL's 2009 expenditures were prudently incurred.

Concentric was also retained to perform an investigation pursuant to an employee concern. Concentric's investigation report, dated June 2010, opined that in 2009, FPL underestimated the risk and costs associated with the fast track project, FPL had not assessed the capacity of the organization and costs, and early warning of cost overruns and undefined scope depletion were not dealt with in a timely manner. However, FPL witness Reed noted that these were lessons learned that FPL discovered as of July 2009, and not conclusions that he generated. He supported FPL's self-critical organization. Based on his review, he did not believe FPL's lessons learned were evidence of imprudence. Witness Reed opined that FPL was an organization that seeks to learn and improve its processes.

FPL retained witness Derrickson, president of WPD Associates, to opine on the prudence of FPL's 2010 EPU project management. WPD Associates is a consulting company specializing in project management. Witness Derrickson reviewed EPU project instruction procedures that he considered most important to project management, as well as, documents required by FPL's procedures, training records, estimates, schedules, presentations to the FPL executive steering committee, and Bechtel metric reports. He also reviewed resumes of senior management personnel and interviewed nine senior management personnel.

Witness Derrickson defined prudence as acting reasonably based upon information available at the time decisions were made and actions taken. He enumerated 12 "ingredients" he believed reflected industry-standard project management principles and indicated that a project was being prudently and reasonably managed. He found FPL employed 11 of the 12 "ingredients": (1) management commitment, (2) financial resources, (3) realistic and firm schedules, (4) clear decision-making authority, (5) flexible project control tools, (6) teamwork-individual commitment, (7) engineering ahead of construction, (8) early start-up, (9) organizational flexibility, (10) ongoing project critique, and (11) owner leadership. The one "ingredient" FPL did not use was the establishment of a temporary office near the NRC's offices to facilitate NRC/FPL dialog. He believed this "ingredient" was not applicable to the EPU project and would not have the same benefits as it would have had in 1981 due to the Internet and current abilities to electronically transfer files.

FPL retained witness Diaz with the ND2 Group, a consulting firm, to review FPL's 2010 St. Lucie Unit 1 EPU LAR activities including FPL's withdrawal and subsequent reapplication of the LAR. He noted that the NRC technical reviewers had unexpected questions exploring support information that was beyond the original design basis for the plant. FPL had no reason, based on prior NRC staff guidance or reviews, to anticipate that analyses on these topics would be requested. He opined that the need to withdraw and resubmit a LAR was driven by evolving NRC expectations and was not evidence of imprudence.

Audit staff witnesses Fisher and Rich also reviewed FPL's project management controls. Their annual reviews addressed both the TP67 and EPU projects. The audit staff witnesses noted that during 2009, FPL's senior management ". . . made the decision to replace the EPU Management team." They opined that:

> Senior management appears to have believed the management team could not provide the necessary control of EPC contractor estimates and that more aggressive actions were required. FPSC audit staff's opinion is that this change was made in part due to performance issues. Though FPL disagrees, an investigation report by Concentric Energy Advisors, Inc. (Concentric) appears to confirm FPSC audit staff's opinion.
>
> As part of FPL's efforts to identify potential efficiencies and improvements in project work scope and schedule, a mid-course review was completed, resulting in significant scope revision and increased project scope changes. An outage optimization conducted in mid-2009 aligned outage and licensing schedules, eliminating overlapping activities, and rescheduling much of the uprate work to longer outages later in the project.
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> Based on the events and developments described above, FPSC audit staff concludes that EPU management was replaced in part due to performance issues. Therefore, FPSC audit staff recommends the Commission closely examine associated project costs in a future proceeding.

On cross-examination regarding the replacement of the EPU management team, audit staff witnesses Fisher and Rich clarified that their 2009 report expressed a belief that at least two of the vice presidents were replaced due to indications that FPL senior management was ". . . not totally happy . . ." with the level of questioning and push back on the engineering, procurement and construction vendor. Audit staff performed a follow-up review and found no direct or compelling evidence of unnecessary work or rework, overpayments, or overcharging by vendors due to any mismanagement on the part of the former EPU management team. The audit staff witnesses further clarified that FPL senior executives were queried on the changeover process and they also reviewed personnel records for both the incoming and outgoing personnel involved. They opined that there was no evidence that changing of vice presidents on the EPU team by senior FPL executives was due to dissatisfaction with the previous management of the EPU project. The changeover appeared to be a matter of normal progression and transition within the company to get the right people in the right jobs at the right time.

Audit staff witnesses Fisher and Rich's report on FPL's 2010 EPU project management and related controls included a discussion of additional matters such as, the potential, but unknown impact, on project costs and schedule due to work stoppages and NRC's response to Japan's Fukushima event. They expressed the following concerns regarding impacts on project costs and schedule:

> Staff is concerned that additional delays during the longer and more complex outages remaining in 2011 and 2012, or increased scope from LAR licensing, may extend project completion further, into late 2013 or beyond. The schedule could also be extended if the NRC fails to approve any of the LARs within the timeframe currently anticipated.
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> During 2010 and early in 2011, FPL experienced several work stoppages and stand down events that created project delays and increased costs. Staff believes that the Siemens St. Lucie 2 work stoppage represents an avoidable event with significant cost impact. FPL claims that the costs are charged back to the responsible contractor to the extent permitted under the contract, but under current rules may submit those not recovered by warranty, liability insurance, or legal remedy through the NCRC recovery process. Staff believes that costs not recaptured by contractual remedies, if submitted for recovery, including the [redacted] in the current FPL request, should be closely examined for suitability under the clause.

FPL witness Derrickson rebutted audit staff's work stoppage testimony. He reviewed each work stoppage and believed FPL had the appropriate contractors to do the necessary work and that FPL had provided adequate training and oversight. Witness Derrickson opined that FPL management performed well by stopping work to protect human life or plant equipment and determine the root cause of the problem. He asserted that thorough analyses were done identifying root-cause problems and produced action plans to remedy each situation as well as prevent future occurrences. He asserted work stoppages were not only appropriate, but necessary to ensure safety and reemphasize training, and not out of the ordinary. He believed FPL acted prudently in each of the work stoppages.

With respect to a work stoppage involving Siemens, FPL witness Jones explained that a portion of the risk was on Siemens, and a portion on FPL. He opined that there were limits of liability on all these contracts and major contract vendors because FPL could not possibly accept the total risk of lost generation or generation replacement as it would put them out of business. He maintained that the portion that FPL was able hold Siemens liable for, Siemens is obligated to pay, and the balance is part of project risk and project expense, and therefore viewed by FPL as recoverable. FPL is currently negotiating with Siemens over the claim.

We find that the recoverability of the work stoppage related costs concern raised by our audit staff witnesses hinges on whether FPL was prudent in training and oversight prior to work stoppages and its response to the facts surrounding the work stoppage. We note that our audit staff's testimony identifies no error or deficiency in FPL's procedures, policies, or other management related controls. As noted above, witness Derrickson attested to reviewing FPL's response to each work stoppage and he found no evidence of imprudence. Nevertheless, we find that ongoing monitoring of FPL's efforts to recover all work stoppage costs reasonably possible from third parties and insurance policies is appropriate.

B. FPL's 2009-2010 EPU Accounting and Related Controls

FPL's EPU accounting and related controls were generally described by FPL witness Powers. Witness Powers asserted that FPL's controls were documented, assessed and audited and tested on a going forward basis by both FPL's internal and external auditors. Witness Powers stated that the 2009 and 2010 costs and controls will have been audited prior to the start of the hearing. Witness Powers asserted these audits will continue to provide assurance that the internal controls surrounding transactions and processes are well established, maintained, and communicated to employees, in order to provide additional assurance that the financial and operating information generated within FPL is accurate and reliable.

C. FPL's Fast Track Management of the EPU Project

OPC, supported by FIPUG and SACE, argued FPL was imprudent in it decision to "fast track" the EPU project. SACE provided no post-hearing discussion. FIPUG provided no post-hearing discussion addressing its position that ". . . many standardized procedures that would have contained costs were omitted."

We note that OPC witness Jacobs used the term "fast track" to describe FPL's EPU project management approach. Various FPL witnesses instead used the term "expedited." We note that both OPC and FPL witnesses referenced FPL's EPU management approach that targets 2012-2013 in-service dates associated with the 2007 need determination. Consequently, the use of different terms reflect a difference without a distinction for purposes of resolving this issue, because regardless of the terminology used, all parties refer to the same EPU project management actions directed to achieve a 2012-2013 target in-service date. Thus, use of the term "fast track" throughout this analysis is a matter of editorial convenience.

FPL's witnesses asserted that FPL's longstanding approach to the EPU project is not new information or a disclosure of information not previously presented to us. Consequently, OPC witness Jacobs' questioning of FPL's fast track EPU management was viewed by FPL as a challenge to all past decisions and actions that lead to the current status of the EPU project. FPL rebuttal witness Deason provided a historical overview. In 2004, we raised lack of fuel diversity concerns. FPL filed a feasibility study in 2005 on coal-fired alternatives. In 2006, we stated that utilities should not assume the automatic approval of natural gas-fired plants. In 2007, FPL proposed the coal-fired Florida Glades Power Park project (Glades), with 2013 and 2014 in-service dates.[15] We did not approve the need.[16] Witness Deason opined that FPL was then left with a need for capacity that reliably and cost effectively provided greater fuel diversity and minimized greenhouse gas emissions. FPL proposed the EPU project to meet those needs. There were no intervenors. We determined that there was a need for the EPU project.[17] Witness Deason noted that:

> FPL's decision to pursue the EPU project on an expedited basis was clearly disclosed in the need determination proceeding. The anticipated in-service dates of the uprates were part of FPL's filing and the cost-effectiveness calculations were consistent with the aggressive time frames. FPL's petition referred to the aggressive schedule of the uprates and FPL's Witness used terms such as "earliest feasible point in time" and "expedited basis" in referring to the EPU project's construction time frame and the ensuing benefits being achieved for customers. If there were concerns that the decision to expedite the process was an imprudent one, the issue should have been raised at that time and it was not.

Witness Deason asserted that we already determined FPL's approach was appropriate. We agree. To date, we have issued five orders addressing various aspects of the EPU project, ranging from the initial need determination in 2007, a 2008 NCRC order, a 2009 NCRC order, and two base rate increase orders addressing plant components that went into commercial service.[18]

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[15] Order No. PSC-07-0557-FOF-EI, issued July 7, 2007, Docket No. 070098-EI, In re: Petition for determination of need for Glades Power Park Units 1 and 2 electrical power plants in Glades County, by Florida Power & Light Company, at page 1.

[16] Order No. PSC-07-0557-FOF-EI, issued July 7, 2007, Docket No. 070098-EI, In re: Petition for determination of need for Glades Power Park Units 1 and 2 electrical power plants in Glades County, by Florida Power & Light Company, at page 5:

> Our decision is based upon our analysis of the record, our deliberation at the June 5, 2007, Agenda Conference, and our determination that FPL has failed to demonstrate that the proposed plants are the most cost-effective alternative available, taking into account the fixed costs that would be added to base rates for the construction of the plants, the uncertainty associated with future natural gas and coal prices, and the uncertainty associated with currently emerging energy policy decisions at the state and federal level.

[17] Order No. PSC-08-0021-FOF-EI, issued January 7, 2008, Docket No. 070602-EI, In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plant, for exemption from Bid Rule, 25-22.082, F.A.C., and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.

[18] Order No. PSC-08-0021-FOF-EI, issued January 7, 2008, Docket No. 070602-EI, In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plant, for exemption from Bid Rule, 25-22.082, F.A.C., and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.; Order No. PSC-08-0749-FOF-EI, issued November 12, 2008, Docket No. 080009-EI, In re: Nuclear cost recovery clause.; Order No. PSC-09-0783-FOF-EI, Docket No. 090009-EI, In re: Nuclear cost recovery clause.; Order No. PSC-10-0208-PAA-EI, Docket No. 090529-EI, In re: Petition to include costs associated with the extended power uprate project in base rates by Florida Power & Light Company.; Order No. PSC-11-0078-PAA-EI, Docket No. 100419-EI, In re: Petition for approval of base rate increase for extended power uprate systems placed in commercial service, pursuant to Section 366.93(4), F.S., and Rule 25-6.0423(7) and 28-106.201, F.A.C., by Florida Power & Light Company.

Nonetheless, OPC witness Jacobs asserted that FPL failed to perform a breakeven analysis, did not have a good handle on the ultimate costs, and was slow to recognize and take into account early indications that its initial estimates were inadequate. He believed these deficiencies constitute imprudence. He generally ascribed the imprudence to FPL employing a fast track approach.

In support of his views, witness Jacobs stated that the EPU project is still in the early stages. He pointed out that FPL has spent only $700 million of an estimated $2.48 billion total. In his opinion, "FPL has to spend almost $2 billion (according to their soft numbers) over the next 18 months of works that is, as of today's date, unplanned and unpriced." He further asserted "[b]ased on what they know now, the almost $2 billion can only be an uneducated guess." He explained how, in general, fast track may result in differences from a traditional approach. He contends that ". . . until the final design is complete the true scope of the project is not known and final cost is impossible to estimate with any degree of accuracy." He further asserted that since the scope is unknown, an engineering and construction contractor will only provide a bid on a "time and materials" basis. He noted that FPL's pace of completing design engineering drawings has been " . . . far slower than that which would be needed to support FPL's implementation schedule." He expressed concern that FPL may undertake construction at risk in advance of the completion of design work, which he believed implied risks to costs, schedule, and NRC review. He concluded ". . . that the decision to fast track these projects and pursue them without performing a breakeven analysis was an imprudent decision on the part of FPL management." He also expects significant increases in project cost and more project delays in the coming two years.

FPL witness Jones provided rebuttal in response to the above criticisms of the status of the EPU project. Regarding time and material-based contracting, witness Jones noted that it provided FPL the greatest control of vendor cost and work scope. As the LAR engineering and design engineering progressed, the work scope became better defined. FPL then negotiated a target price with the EPC vendor for St. Lucie. FPL plans to do the same for the Turkey Point EPC contract.

FPL witness Derrickson opined that proceeding with the fast track option does not forego the price assurance aspects of a contract based upon full specifications. He gave the example that if a bigger moisture separator reheater was desired then a vendor would lock itself into a price-certain contract for the work. He also opined that it is not uncommon on nuclear projects to be required to order material before the project even starts. He asserted that it is done all the time. If a shortened schedule is desired, then the risk must be taken and the equipment ordered before the job starts. He clarified that the risk is with respect to not proceeding with the project.

Regarding the pace of completing engineering, FPL witness Jones noted that engineering had not progressed as originally planned because more engineering had been needed. He asserted that FPL will adjust its EPU project schedule and outage schedules from time to time as circumstances warrant. Witness Jones noted that FPL is currently on track for the successful completion of this project, and based on all the information known today, customers were already benefitting and were expected to benefit substantially in the future from the EPU project.

In response to OPC witness Jacob's view that FPL's estimate of the ultimate EPU project cost is an uneducated guess, FPL witness Jones countered:

> FPL's current non-binding cost estimate is more defined now than it has been in previous years. This definition comes from the completion of the LAR engineering, the completion of about 70% of the design engineering, and the information learned from the early stages of implementation. FPL's non-binding cost estimate is therefore highly informed. It reflects three years of project experience and advancement, as well as the input from an independent project estimating expert, Highbridge Associates (as described in my March 1, 2011 testimony addressing the EPU project in 2010, p. 27), and a new target price contract with one of FPL's primary vendors (as described in my May 2, 2011 testimony, p. 7). Nonetheless, the non-binding cost estimate still accounts for the fact that more design engineering needs to be accomplished.

FPL witness Jones noted that the year-to-year trends in the increases in the non-binding cost estimates have trended in the right direction, from 28 percent down to 8 percent. Regarding necessary support to complete EPU work during plant outages, he noted that the plant change modification packages required for support of St. Lucie Unit 1's Fall 2011 EPU outage were 90 percent complete or greater. He was confident that the required support will be completed for the EPU outages. FPL witness Sim opined that by a year from today, 2 of the nuclear uprate projects will be completed, approximately 3 or 4 months later in 2012 the third, and in March 2013 the fourth will be completed.

When OPC witness Jacobs was asked if he found any evidence of imprudent actions taken by FPL in 2009 and 2010, he replied:

> No. No, I didn't. They were, they were committed to a fast track approach. The results of that commitment were the costs were increasing and the scope of the project was increasing beyond what they had originally estimated it to be. But by the 2009/2010 time frame they were committed to that approach, and I believe they were addressing those issues prudently at that point in time.

OPC witness Jacobs later reaffirmed this assessment during subsequent questioning. We note that witness Jacobs did not identify any of the 2009-2010 cost increases he attributed to a fast track approach as unreasonable or unnecessary to implement the EPU project. Had there been evidence that the costs were unnecessary or not needed to pursue the project, then those costs should not be recovered.

In its brief, FIPUG argued that FPL admitted that it underestimated the risks and costs for fast tracking and referenced Concentric's investigation report. However, as we noted, FPL witness Reed, who sponsored the Concentric investigation report, did not believe FPL's self-critical review was a demonstration that imprudence had occurred.

In its brief, OPC argued FPL's imprudence manifested itself in the form of a $700 million increase in the project estimate. During his deposition, OPC witness Jacobs explained that his concern with FPL's fast track approach is not that FPL may incur higher EPU project costs, but that FPL continues to pursue the EPU project that he believes is not economically feasible.

> Q. Okay. So your concern with the fast-track is that FPL may be incurring higher construction costs rather than if FPL had not proceeded with the fast-track of the uprate project?
>
> A. Well, not exactly. It's more that in deciding on the fast-track they were essentially committed to the project with very little to no design engineering completed and really not a good understanding or estimate of the final cost of the projects, or what the final cost needed to be. And yet they committed to a multi-billion dollar project with really not understanding what the costs would turn out to be or what the costs needed to be for the project to be economically feasible.
>
> So if they had used a more traditional approach where they completed the design engineering which would then allow them a much better idea of the total scope of the project and likely be able to get firmer bids from contractors, because the scope would be more well-defined, that would have allowed them to do a better – make a more informed decision about whether to go forward with the project.
>
> Q. So if FPL had not proceeded with the fast-track, Doctor Jacobs, would you still be advocating a break-even analysis that compares nuclear to non-nuclear options?
>
> A. Yes. Let me clarify that. I would say initially a break-even analysis would have been more appropriate. As the design became finalized and the final cost became certain, then at that point perhaps they could have used the CPVRR type analysis.
>
> Q. Would you agree, Doctor Jacobs, that one way to assess the effects of the fast-track project management decision is to compare the nonfast-track to the fast-track option for the same technology choice?
>
> A. No, because my concern is that if they had used a traditional management approach and determined early on what the scope and the cost of the project would have been, it might have led them to conclude that this project was not feasible at an early point in time where a lot of money had not been spent. I think your question assumes that the project proceeds ahead under both scenarios.

We find that the above testimony suggests that witness Jacob views the cost increases relative to the original project estimate would have likely occurred even without a fast track approach. In its brief, FPL argued that there is no basis for OPC witness Jacobs' claim that project costs were higher due to FPL's EPU approach. We agree.

During oral argument regarding FPL's request to strike testimony sponsored by OPC, OPC counsel argued that it was asking this Commission " . . . to gauge the prudence of FPL based on what was the information that it had at the time it made the decision to fast track." We note that the information OPC witness Jacobs relied on was FPL's filings in this docket and FPL's responses to discovery. His understanding was that FPL originally contemplated proceeding using a traditional approach. The evidence his filed testimony identified was a deposition transcript of Mr. Kundalkar, a retired FPL employee. The deposition transcript of Mr. Kundalkar shows discussion regarding the timing of FPL's fast track decision occurred twice.

> Q. I think we will get to that. There's another column called: Scope not estimated. What does that term mean?
>
> A. Mr. McGlothlin, this was a fast-track project, so when we undertook this project, we were doing a number of these functions in parallel. And normally when we execute these large complex projects, we do initial scoping study, then do detailed engineering analysis, and then we do detailed engineering design. And once those drawings are available, then we do construction planning, then do construction estimate, and at that time establish contingency for the implementation of that job and then implement.
>
> That process, in the initial planning stage, would have taken us many years past the year in which there was need for electricity for Florida's customers. Originally, this project was going to be completed much later. So when we - - so when we established there was a need for electricity of a certain magnitude in 2012 and we were asked if we were to do this as a fast-track project, can we implement that, and in doing so what are the unknowns?
>
> And one of the unknowns, or one of the things, risk factors we need to account for is identify and allocate that there may be certain scope activities not identified as part of the scoping study and they could be discouraged. So allocate appropriate amount of money for scope not identified, which will be identified as part of the detailed analysis, part of the detailed design. That's part of discovery.
>
> Therefore, a large percentage of amount was placed in that bucket, which is here described as scope not estimated. As I recall it may have been in the range of forty-five or fifty percent, roughly like that. So, that's what that amount was.
>
> Q. I will try. In an earlier answer you said: We were asked about the fast-track possibility after FPL had originally planned to construct the uprates in the more typical fashion and have it placed in service at a much later date. When you say: We were asked about the fast-track, who would have been posing that question to you?
>
> A. It would be senior executive management, and as I recall it was a - - about the time when the Glades coal-fired plant was not approved for construction or implementation by PSE [sic], so it may have been earlier part of 2007.

However, FPL witness Stall rebutted that OPC witness Jacobs misread the deposition passage. FPL witness Stall was Chief Nuclear Officer at the time of FPL's EPU project need determination. FPL had previous preliminary engineering information regarding the feasibility of uprating the nuclear units but had not made plans to execute the project. That occurred when we denied FPL's petition for the Glades project. It was then that FPL senior management decided to pursue the EPU project as quickly as reasonably possible. He further asserted that there was never any plan to pursue the EPU project in a sequential manner. FPL witness Stall noted that he had also been deposed on this same matter on June 1, 2011.

We note that the deposition transcript that OPC witness Jacobs relied on to assert FPL originally contemplated a traditional approach is similar to the rebuttal testimony of witness Stall in that the timing of FPL's fast-track decision was in response to an identified 2012 need and after we denied the Glades project. Witness Jacobs' exhibit also clearly stated that the EPU project was undertaken as a fast track project. Consequently, we do not find any inconsistency between the information OPC witness Jacob's relied on in exhibit and the testimony of FPL witness Stall.

We have reviewed the testimony of witness Jacobs for additional analysis addressing the reasonableness of a traditional approach in meeting the 2012 need and found none. Therefore, OPC witness Jacobs simply asserted that implementation of a traditional approach would have resulted in a different outcome. We note that FPL does not dispute the consequence of the given premise. FPL witness Jones asserted that if FPL had chosen to sequentially implement the EPU project, the project would have taken eleven and a half years, or six years longer. He also believes that the total project costs would have been significantly greater. The estimated fuel savings would have been at least $840 million less.

In light of the above, we find that the question arises whether a traditional approach was a reasonable option for the EPU project to achieve the target 2012-2013 in-service dates. As noted above, the project would have taken longer and resulted in less fuel savings. Witness Olivera stated:

> To be very clear, absent the assurances requested by FPL and provided by the Commission in its EPU project need determination order that the nuclear cost recovery regulatory framework would be applied to the EPU project, FPL would not have undertaken the EPU project on an expedited basis and would have constructed natural gas fired generation.

Therefore, based on the record evidence, we are hesitant to place any weight on the assumption that a traditional approach was a reasonable option when considering all relevant facts and circumstances surrounding FPL's decision, because there is no dispute that a traditional approach to the EPU project would not have met the target 2012-2013 need requirements and would have resulted in less customer fuel savings. We find that the record demonstrates that FPL's decision to implement the EPU project using a fast track approach was dependent on the outcome of its EPU need petition.

We note that FPL's EPU need petition filing requirements are described in Section 403.519(4), F.S. The statute requires the petition to contain a nonbinding estimate:

> A description of and a nonbinding estimate of the cost of the nuclear or integrated gasification combined cycle power plant, including any costs associated with new, expanded, or relocated electrical transmission lines or facilities of any size that are necessary to serve the nuclear power plant.

(403.519(4)(a)3., F.S.)

OPC argues ". . . that far more information is available now as compared to the time of the 2007 need docket." We agree. We find that the new information exists because of the following FPL actions. In 2009, FPL undertook a mid-course review to reassess the scope, schedule, and costs for the EPU project. The mid-course review resulted in significant revision and increased project scope. In August 2009, FPL undertook an outage optimization review. FPL also initiated a third-party assessment and independent budget estimate for uprate activities at Turkey Point Unit 3 to validate necessary work scope, modifications, implementation strategy, and range of costs. FPL developed an updated non-binding cost forecast range for the EPU project reflecting increased scope. The updated cost range is $2,323,713,700 to $2,479,030,970 including transmission costs and carrying costs. As previously noted, OPC witness Jacobs did not find evidence of imprudence concerning FPL's 2009 and 2010 activities.

OPC argued that recent increases in estimates of capital costs were changed circumstances and justify witness Jacobs' recommendation that break even analysis was required. We note that to the extent new information changed circumstances, then that information is considered in the review of the feasibility of completing the project. There is no record evidence demonstrating FPL could have or should have known of these increases prior to the reviews it performed during 2009-2010. Thus, we find that the appearance of the new information, absent hindsight review, does not demonstrate imprudence regarding FPL's fast track decision.

D. Proposal to Use a Breakeven Analysis to Set FPL's EPU Rate Base

As previously noted, OPC's position is supported by SACE and FIPUG. SACE provided no post-hearing discussion. FIPUG argued that FPL failed to provide a breakeven analysis and failed to include sunk costs in its evaluation of the cost-effectiveness of the EPU project.

OPC argued that "[j]ust as one cannot reconstruct the costs that FPL would have incurred had it not fast tracked the EPU, one cannot review the prudence of individual costs or tasks in isolation of an overall approach to the assessment of the impact of FPL's decision to fast track." Therefore, OPC argues, it is desirable to develop the best possible proxy for that information. OPC argued that we should direct FPL to calculate the maximum amount that it can invest in the EPU project and remain cost-effective using a breakeven calculation.

We disagree because, as discussed above, the EPU project would not have been undertaken but for FPL's fast track approach because of the target 2012-2013 in-service dates and fuel savings. Consequently, assuming that FPL was imprudent to fast track the EPU project, then, consistent with the testimony of witnesses Jacobs, Jones, Sim, Stall, Derrickson, and Olivera, the EPU project would not be a reasonable or prudent project in its entirety. The only viable alternative would be the construction of a natural gas combined cycle facility. A better proxy of FPL's costs under the non-fast track scenario may be those FPL has incurred for a recent combined cycle project. Nevertheless, as discussed more fully below, OPC's witnesses maintained that we should assess how much FPL should be authorized to spend on the project.

OPC witnesses Jacobs and Smith seek a backstop that would limit FPL's ability to recover all costs associated with the EPU project. OPC witnesses' proposed use of a breakeven analysis, similar to FPL's TP67 project feasibility breakeven analysis with inclusion of all dollars spent beginning in 2009. OPC witness Smith explained that he first selected one of FPL's current resource expansion plan comparisons - FPL's medium fuel and medium environmental analysis. He then subtracted the amounts previously spent on the EPU project. He asserted that the purpose is "[t]o gauge whether customers are receiving a net benefit or net cost from an overall perspective . . . ." He asserted that if the result is positive, then the EPU project is cost-effective. He opined that the resultant breakeven amount should be the maximum EPU project amount allowed to be included in rate base. He concluded ". . . that the Commission should adopt a method of viewing the project that will enable it to identify and disallow costs that exceed the maximum amount that would be cost-effective for customers." Witness Smith believed "[t]his would protect FPL's rate payers from costs (associated with the plan that FPL has identified as its least cost choice) that exceed those associated with what it has identified as its second best choice."

OPC witness Jacobs also supported use of a breakeven analysis:

> . . . the main benefit of that is it provides a specific number that you can easily relate to the project costs. In the CPVRR analysis, it provides a range of savings compared to the alternative generation portfolio, but it's not easy to relate that number to the project cost. If you have a break-even type analysis, you can say that above this specific number the project is no longer economic, so it makes it easy to determine whether or not the project is economic, especially on a project where the cost and the price continues to escalate. It kind of gives you a line in the sand, and you can say, well, if we go above that number, it is no longer economic.

We note that OPC witness Jacobs' prefiled testimony presented, among other things, a recommendation that FPL perform a breakeven analysis every year and the annual recoverable amount be trued-up based on the then most recent breakeven analysis. His breakeven testimony gave rise to rebuttal testimony filed July 25, 2011, by FPL witnesses Derrickson, Olivera, Deason, Reed, Jones, Stall, and Sim. Subsequent to FPL filing its rebuttal testimony, during a deposition on August 2, 2011, OPC witness Jacobs revised his recommendation to require only one breakeven analysis, which would be performed when the EPU project is completed. He appeared to support his deposition testimony during his summary of his prefiled testimony by referring to the final breakeven analysis. Consequently, our analysis does not address FPL's witnesses' rebuttal testimony regarding true-up aspects associated with OPC witness Jacobs' original recommendation that he no longer supported during live testimony.

OPC argued that assessing the impact of the decision to fast track can only be determined by comparing actual costs to the costs that would have been incurred had FPL not fast tracked. Accordingly, a proxy calculation is needed. As previously noted, the proposed proxy OPC's witnesses selected was FPL's medium fuel and medium environmental analysis. FPL witness Sim asserted that the selection of a single scenario and group of assumptions has the appearance of an arbitrary standard. We believe that a project feasibility analysis should consider various factors, including long-term fuel and environmental forecasts. Included in these analyses are a myriad of assumptions, few of which are 100 percent certain. As addressed above, we have considered the uncertainty of the long-term future in our review of the feasibility of completing a project.[19] This has been accomplished by reviewing a range of possible future scenarios. FPL witness Deason stated that the breakeven analysis was never intended to be a tool to deny the recoverability of otherwise prudently incurred costs. Consequently, OPC witness Jacobs' desire to have a "line in the sand" using a single long-term expansion plan breakeven estimate may not be an appropriate use of a long-term generation expansion planning tool.

FPL witness Reed did not support OPC witness Jacob's recommendation because he asserted it puts FPL in the position where recovery of EPU project costs are not determined by FPL's actions, but rather by factors that are outside of its control. He provided the following example:

> If the forecasted price of natural gas (or any other forecasted input that may affect the resource plan that excludes the EPU Project to a greater extent than the resource plan that includes the EPU Project) drops precipitously in any given year, Witness Jacobs' [sic] breakeven amount could theoretically drop below amount FPL has already spent on the EPU project that the Commission has determined to have been prudently incurred. This scenario would put the Commission in the position of disallowing previously approved, prudently incurred costs. In addition, the reason for the disallowance would not be any action or inaction on the part of FPL, but rather it would be due to something completely out of FPL's control.

OPC witness Jacobs affirmed that future fuel prices were among the factors beyond the utility's control that were included in the breakeven analysis. However, we note that Section 403.519(4)(e), F.S., states in part that "[i]mprudence shall not include any cost increases due to events beyond the utility's control." Witness Jacobs believed FPL accepted the risk of future

[19] Order No. PSC-09-0783-FOF-EI, at pages 13 through 16, addresses a range of forecasted fuel and environmental costs associated with the TP67 project. Pages 33 through 34 similarly addresses the same subject matter regarding PEF's Levy project. Order No. PSC-11-0095-FOF-EI, pages 19-37, is a review of PEF's 2010 NCRC feasibility analysis for the Levy project and the CR3 Uprate that includes ranges of forecasted fuel and environmental costs.

changes in gas prices and other parameters. Other than his stated opinions, we found no other evidence supporting his views concerning factors beyond FPL's control.

In a footnote on page 33 of its brief, OPC attempted to propose a further refinement of its witnesses' recommendation intended to address factors beyond a utility's controls:

> The argument has been made that the final breakeven analysis may be affected by such factors as swings in fuel costs that are beyond the utility's control. There would be nothing to prevent FPL from preparing the analysis using more than one fuel cost scenario to account for any such development. However, the excess investment above the breakeven amount would serve as a basis for quantifying disallowance of imprudent cost, absent a showing by FPL that other factors should offset or diminish the differential.

We note that OPC's elucidation does not detract from the fundamental characteristic that long-term expansion plan analysis is intended to reflect the impact of factors beyond the utility's control on a given long-term plan. Scenario analysis is for the purpose of testing whether the forward-looking plan is robust through use of ranges in the factors that are beyond utility management control. Thus, while OPC's expanded view may allow FPL more latitude as to which breakeven analysis it may chose to defend, we find that the change does not alleviate tension between the proposal and Section 403.519(4)(e), F.S. OPC further argued that we should interpret what constitutes "certain costs" in Section 403.519(4), F.S., as being the difference between the actual costs and the final breakeven values. However, as we addressed below, the breakeven analysis suggested by OPC relies on hindsight and does not distinguish between prudent and impudent FPL management actions and resultant costs. Consequently, OPC's suggestion to interpret or define what constitutes "certain costs" in Section 403.519(4), F.S., implements hindsight review and does not consider specific management actions or resultant costs.

FPL rebuttal witness Deason opined that OPC's proposal could preclude FPL from otherwise recovering prudently incurred costs. This is because the limitation is on a total investment basis and does not distinguish prudently incurred costs from imprudently incurred costs. Witness Deason noted that "[t]here is nothing magical about the break-even point that makes cost become unreasonable or imprudent, as Witnesses Jacobs and Smith imply." It is the nature of cost themselves and whether the cost have been prudently incurred and well managed that determines their recoverability. He opined that applying the breakeven alternative introduces a standard based on a backward-looking determination of costs eligible for recovery. He also stated "[t]he use of 20-20 hindsight to conclude a decision was imprudent is improper." FPL witness Deason stated that:

> Sitting here today, we don't know what the relationship is going to be with a breakeven analysis at the time that these, this EPU project is completed. It could be below that, it could be above. But the fact that it is above does not mean that there has been one dime of cost incurred imprudently, and that's how it violates the policy that has been established by the Legislature and this Commission.

Witness Deason further asserted that we could use a breakeven analysis to determine the continued viability of the project. However, he believed its proposed use to limit recovery of costs that would otherwise have been determined to be prudent is inappropriate. FPL witness Reed similarly opined that OPC witness Jacobs' proposed approach to wait until the end of the project to determine what portion of the project costs is included in rates is bad regulatory construct and conflicts with the intent of the statute in providing assurances that prudently incurred costs can be recovered.

During his deposition, OPC witness Jacobs was questioned regarding the ultimate economic feasibility of the EPU project and the treatment of costs that have previously been deemed to be prudently incurred:

> Q. Have you done the analysis to which you are referring to on page 28, lines 11 through 14?
> A. No. I have not specifically calculated those break-even costs.
> Q. Okay. So let me ask you this. Are you recommending that the Commission true-up amounts that were recovered to the new break-even amount annually?
> A. No. I think that could be done at the end of the project when the final cost is known. The concern here is that the amounts collected in '09, '10, '11, the earlier years, and those that have already been deemed to be prudent wouldn't then be subject of a disallowance. That would occur at the end of the project.
> Q. When you say the amounts to be collected, just for clarification, are you talking about AFUDC or are you talking about the rate when it goes into the base rate account, base rates, excuse me?
> A. I hadn't really thought about that. I guess really since the amounts collected are only for carrying costs during the construction period, so really this is referring to I would say both.

While it appears that OPC witness Jacobs believes that prudently incurred costs will not be subject to disallowance, he nonetheless proposed that the final breakeven analysis include sunk costs. OPC argued that we should disallow as imprudent the difference between the actual EPU project costs and the final breakeven value. Consequently, we are confused regarding how OPC's proposal provides for recovery of costs previously found prudently incurred because the proposal requires inclusion of all costs, even those previously deemed prudent, to determine the extent of FPL's imprudently incurred costs.

We note that OPC witness Smith intended to "[t]o gauge whether customers are receiving a net benefit or net cost from an overall perspective . . ." He also recommended that the breakeven analysis include all costs spent beginning in 2009. We find that this means the stated intent of his analysis is to apply hindsight and compare the total completed EPU project costs together with a then-current expansion plan against an all-natural gas expansion plan from 2009 forward. Thus, his proposal appears to require a comparison that includes all sunk costs, even those that have already been included in base rates. As we previously noted, FPL has petitioned for and received two base rate increases for EPU project components. It would appear that these amounts would again be subject to review and adjustment using OPC's proposal. Yet, witness

Smith asserts that costs included in base rates should be excluded. Consequently, we find that witness Smith's testimony regarding sunk costs appears inconsistent, especially concerning those portions of the EPU project costs that were phased into base rates.

OPC argued ". . . there is an overriding public interest of ensuring that FPL's customers are not saddled with either an uprate project that no longer is economically feasible or with excessive costs growing out of imprudent decisions." We agree that FPL should only recover prudently incurred costs. We note that the cost escalation concern was an argument previously presented by intervenors in support of a risk sharing mechanism.[20] We determined that we do not have the authority to ". . . require a utility to implement a risk sharing mechanism that would preclude a utility from recovering all prudently incurred costs."[21]

Based on the above analysis, we find that, as asserted by various FPL rebuttal witnesses, the methodology recommended by OPC witnesses Jacobs and Smith may result in hindsight review of prudence by use of future facts and assumptions to determine the extent of current or past prudently incurred costs. Moreover, the evolving nature of OPC's proposal, the possibility of inappropriate use of long-term planning, and the possibility of limiting FPL's ability to recover costs previously deemed to be prudently incurred, are aspects that lead us to question the adequacy of record evidence in support of adopting the proposal. Accordingly, we reject the proposal of the OPC witnesses.

E. Prudence Standard

We find that the appropriate guidance for determining prudence is found in our prior Orders. Order Nos. PSC-08-0749-FOF-EI and PSC-09-0783-FOF-EI set forth our view of prudence: ". . . the standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should been known, at the time the decision was made." (Order No. PSC-08-0749-FOF-EI, p. 28; Order No. PSC-09-0783-FOF-EI, p. 26) Section 403.519(4)(e), F.S., provides the following:

> After a petition for determination of need for a nuclear or integrated gasification combined cycle power plant has been granted, the right of a utility to recover any costs incurred prior to commercial operation, including, but not limited to, costs associated with the siting, design, licensing, or construction of the plant and new, expanded, or relocated electrical transmission lines or facilities of any size that are necessary to serve the nuclear power plant, shall not be subject to challenge unless and only to the extent the commission finds, based on a preponderance of the evidence adduced at a hearing before the commission under s. 120.57, that certain costs were imprudently incurred. Proceeding with the construction of the nuclear or integrated gasification combined cycle power plant following an order

[20] Order No. PSC-11-0095-FOF-EI, issued February 2, 2011, Docket No. 100009-EI, In re: Nuclear cost recovery clause, at page 7.
[21] Order No. PSC-11-0095-FOF-EI, issued February 2, 2011, Docket No. 100009-EI, In re: Nuclear cost recovery clause, at page 9.

> by the commission approving the need for the nuclear or integrated gasification combined cycle power plant under this act shall not constitute or be evidence of imprudence. Imprudence shall not include any cost increases due to events beyond the utility's control. Further, a utility's right to recover costs associated with a nuclear or integrated gasification combined cycle power plant may not be raised in any other forum or in the review of proceedings in such other forum. Costs incurred prior to commercial operation shall be recovered pursuant to chapter 366.

As discussed above, concerns regarding fast track project management decisions were raised by the intervenors. The evidence supporting the intervenors' asserted imprudence relied on speculation that had FPL not pursued fast track implementation, FPL might have identified potential cost increases early on and then decided not to complete the project. The evidence supporting this asserted imprudence, such as increased non-binding EPU project cost estimates, also relied on hindsight. We find that speculation and hindsight review is not consistent with the prudence standard recognized by us and shall be rejected as a basis for finding imprudence. We note that FPL's 2009 and 2010 costs are, in part, the result of our prior decisions, and were subject to review in various prior proceedings. In this proceeding, there was no record evidence concerning FPL's fast track approach that would provide cause to revisit our prior decisions.

Based on the foregoing, we find that FPL's 2009-2010 EPU project management and accounting with related controls were subjected to a reasonable level of review and examination sufficient to determine prudence. We find that there is no record evidence identifying any FPL 2009 or 2010 EPU project management decisions or accounting as unneeded or unreasonable. Based on a preponderance of the record evidence, we find that FPL's fast track management decisions were prudent and OPC's recommendation to require a breakeven analysis to set rate base recovery limits shall be rejected.

F. Conclusion

Therefore, we find that project management, contracting, accounting and cost oversight controls employed by FPL during 2009 and 2010 for the EPU project were reasonable and prudent. We also find that FPL's fast track management decisions were prudent.

XIII. 2009-2010 Prudence of EPU Incurred Costs

This issue addresses FPL's request concerning the prudence of its 2009 and 2010 EPU incurred costs and the final true-up of recovered amounts for 2009 and 2010. No testimony by parties or audit staff witnesses proposed adjustments to FPL's requested amounts. We note that our findings in this matter must be consistent with the resolution of FPL's EPU management prudence determinations discussed above. OPC, FIPUG and SACE took positions consistent with their arguments regarding fast track project management that is addressed above. Aside from these matters, no additional concerns were raised regarding the disposition of FPL's 2009 and 2010 EPU project costs.

FPL witness Powers provided support for the 2009 and 2010 EPU project costs and methods used to determine the requested final true-up recovery amounts. FPL witness Jones provided descriptions of the 2009 and 2010 EPU project activities, costs, and variances.

A. 2009 EPU Incurred Costs and Final True-up Amount

Witnesses Powers and Jones identified 2009 EPU construction capital costs of $237,677,629 ($236,605,950 jurisdictional net of joint owners and other adjustments). They also indicated the associated carrying costs incurred during 2009 were $16,459,883, and operations and maintenance (O&M) costs were $498,077 ($480,934 jurisdictional net of joint owners). FPL requested that we review and approve these amounts as prudently incurred. In support of the request, FPL witness Jones stated:

> Significant progress was made in 2009, including continued engineering evaluation and analyses in support of EPU License Amendment Request (LAR) submittals to the Nuclear Regulatory Commission (NRC), the submittal of the PTN Alternative Source Term (AST) LAR to the NRC, activities and quality inspections related to the manufacture of long lead equipment, the management and implementation of the Engineering Procurement and Construction (EPC) contract, and detailed reviews of the modification installation planning and EPU outage schedules. Also, FPL made adjustments to the project organizational structure reflecting a shift of responsibilities to the individual sites, revised several project instructions, and continued with project staffing.

Witness Jones also provided a listing of equipment modifications or replacements, as of December 2009, that included a description addressing why the actions are needed. He also presented a project schedule as of December 2009, indicating the various overlapping activities from a 2007 project inception date through 2013.

FPL's year-ending 2009 incurred costs were $21,319,066 less than its May 2009 estimate. FPL spent $7,927,904 more in licensing costs due to the preparation of more analyses than estimated and a longer period of contractor mobilization than estimated.[22] Project permitting costs were $410,295 more than estimated due to increased scope of the Turkey Point Cooling Canal monitoring program required by the Compliance of Certification of the Site Certification Application. Engineering and design costs were $1,903,374 more than planned due to LAR scope growth and management of the EPC contractor engineering efforts. FPL incurred $4,703,290 less than estimated in project management costs due to the shift of more of the field management responsibilities to the EPC vendor and outage staffing revisions. Power block engineering and procurement costs were $26,572,962 less than estimated due to less than expected EPC contractor usage, deferral of some milestone payments, and rescheduling of certain plant modifications. FPL also incurred $445,101 more than estimated for non-power block engineering, and procurement due primarily to simulator modifications incurred earlier than planned. Transmission-related expenses were $659,565 less than planned, primarily due to

[22] Contractor mobilization consists of preparatory work that includes movement of personnel, equipment, and supplies to the project site.

a revised schedule of planned activities. O&M was less than estimated by $69,923. The variance was attributed to the nature of expenses included in the O&M category such as the expensing of obsolete inventory. No party or audit staff witness identified any specific amount of FPL's 2009 EPU project costs as imprudently incurred.

Witness Powers explained that the year-ending 2009 project costs were compared to our prior approved and recovered amounts to determine the net final true-up amount for 2009 of negative $3,971,698. The requested 2009 net final true-up amount includes the following items: over-projected carrying costs of $3,837,507, over-projected O&M costs of $63,533 including interest, and overestimated base rate revenue requirements of $70,658. FPL is not requesting that these amounts be used to determine the 2012 total NCRC recovery amount because the amounts were already included in FPL's 2011 CCRC.

B. 2010 Incurred Costs and Final True-up Amount

Witnesses Powers and Jones identified 2010 EPU construction capital costs of $309,982,999 ($289,147,514 jurisdictional net of joint owners and other adjustments). They also indicated the associated carrying costs incurred during 2010 were $41,568,087, and O&M costs were $7,176,395 ($7,067,402 jurisdictional net of joint owners). We note that FPL included a $5,983 true-up interest amount in its calculation of the jurisdictional O&M amount. FPL requested that we review and approve these amounts as prudently incurred. In support of the request, FPL witness Jones stated:

> Several key activities occurred in 2010, including: (i) submittal of the St. Lucie Unit 1 EPU LAR, the Turkey Point Units 3 and 4 EPU LAR, and the Turkey Point Spent Fuel Criticality LAR to the NRC for review and approval, and continued engineering analyses in support of submitting the St. Lucie Unit 2 EPU LAR; (ii) the execution of the vendor contracts for long lead procurement equipment, as well as quality inspection, receipt, and storage of long lead procurement items; (iii) modification engineering for the St. Lucie and Turkey Point Units and continued management of the EPC vendor; (iv) receipt of independent third party estimate of implementation man-power requirements and costs; (v) preparation for, and successful execution of, implementation activities during the St. Lucie Unit 1 spring 2010 outage and the Turkey Point Unit 3 fall 2010 outage; and (vi) adoption of revisions to the planned future outage durations.

FPL's year-ending 2010 incurred costs were $4,219,700 less than its May 2010 estimate. FPL spent $3,143,847 less in licensing costs due to less than expected NRC review costs. Project permitting costs were $98,818 more than estimated due to environmental work in the preparation of an application to the Florida Department of Environmental Protection addressing discharge temperature for the St. Lucie Plant. Engineering and design costs were $7,794,123 more than planned due to LAR scope growth and management of the EPC contractor engineering and implementation efforts during the 2010 outages. FPL incurred $2,568,397 more than estimated in project management costs due to increased FPL project and construction management oversight of the EPC vendor. Power block engineering and procurement costs were $19,384,902 less than estimated, primarily due to shifts in the scheduling of modifications to different outages and deferrals to a later year. FPL also incurred $1,974,828 less than estimated for non-power block engineering and procurement, due primarily to simulator modifications being rescheduled. Transmission-related expenses were $5,858,469 more than planned, primarily due to reclassification of plant engineering for procurement and installation of a main transformer. FPL experienced an O&M variance of a $3,964,070 increase. The variance was attributed to the nature of expenses included in the O&M category such as contract staff. No party or staff witness identified any specific amount of FPL's 2010 EPU project costs as imprudently incurred.

Witness Powers explained that the year-ending 2010 project costs were compared to the prior estimate for 2010 to determine the net final true-up amount for 2010 of $1,531,532. The requested 2010 net final true-up amount includes the following items: overestimated carrying costs of $784,236, underestimated O&M costs of $3,926,433 including interest, and overestimated base rate revenue requirements of $1,610,665, including carrying charges.

We note that OPC's position on this issue would require us to find FPL imprudently incurred some portion of the 2009 and 2010 EPU project costs and carrying charges, but withhold any disallowance for that imprudence until some future analysis is performed. Thus, if we were to agree with OPC, SACE and FIPUG concerning FPL's imprudence to fast track the EPU project and that a breakeven analysis is necessary, then there is no adjustment to FPL's 2009 and 2010 amounts at this time; instead, we should find FPL's 2009 and 2010 EPU amounts to be subject to refund and/or disallowance pending review of an ultimate future breakeven analysis. However, as addressed above, we reject the arguments of OPC, SACE and FIPUG.

C. Prudence Standard

As discussed above, the standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should been known, at the time the decision was made. We note that OPC witness Jacobs' concerns regarding FPL's fast track project management approach were the only reasonableness or prudence concerns raised. When asked by us if he found any evidence of any action taken by FPL in 2009 and 2010 that was imprudent, OPC witness Jacobs replied "no." No additional concerns were raised. No party or audit staff witnesses identified items, activities, or costs included in FPL's 2009-2010 EPU project filings as unnecessary to complete the EPU project.

Consistent with our findings above, our verification of FPL's calculations and true-up amounts, and a preponderance of the evidence in the record, we find that FPL has demonstrated the prudence of its 2009 and 2010 incurred costs and appropriately determined the respective NCRC final true-up amounts for the EPU project.

D. Conclusion

Therefore, for 2009, we approve as prudently incurred EPU project capital costs of $237,677,629 ($236,605,950 jurisdictional net of joint owners and other adjustments) and O&M costs of $498,077 ($480,934 jurisdictional net of joint owners). The final 2009 true-up amount, net of prior recoveries, is negative $3,971,698, and will be fully refunded during 2011. No further action shall be required regarding FPL's 2009 incurred costs.

For 2010, we approve as prudently incurred EPU project capital costs of $309,982,999 ($289,147,514 jurisdictional net of joint owners and other adjustments) and O&M costs of $7,170,412 ($7,067,402 jurisdictional net of joint owners). The final 2010 true-up amount, net of prior recoveries, is $1,531,532, and shall be used in determining the net total 2012 NCRC recovery amount.

XIV. Reasonableness of 2011 EPU Estimated Costs

This issue addresses FPL's request concerning the reasonableness of its 2011 EPU incurred costs and the estimated true-up amount for 2011. No testimony by parties or audit staff witnesses proposed adjustments to FPL's requested amounts. The only concern raised was FPL's fast track approach which was addressed above.

FPL witness Powers provided support for the 2011 EPU project costs and methods used to determine the requested estimated true-up recovery amount. FPL witness Jones provided descriptions of the 2011 EPU project activities, costs, and variances.

Witness Powers submitted an errata that identified changes to her prefiled testimony and exhibits. While there was no dispute regarding the errata, we note that the errata did not reference Exhibit 70, nor was Exhibit 70 corrected to reflect the same errata where applicable. We verified that, had the schedules been updated, the summary amounts in Exhibit 70 would be consistent with FPL's errata. Therefore, for purposes of our review, we reference to Exhibit 70 is as revised consistent with FPL's errata.

FPL witnesses Powers and Jones identified the estimated 2011 EPU construction capital costs of $587,845,328 ($558,520,431 jurisdictional net of joint owner and other adjustments), and O&M costs of $12,721,405 ($12,249,329 jurisdictional net of joint owner and other adjustments). We note that FPL's amount includes a $14,488 interest true-up in its calculation of the jurisdictional O&M amount. They also identified the estimated 2011 construction carrying costs as $70,287,307. Additionally, they presented the calculation of an estimated base rate revenue requirement of $16,585,797 for phases of the EPU project that are expected to go into commercial service in 2011. In support of these amounts, FPL witness Jones stated:

> In 2011, FPL expects to complete the Engineering Analysis Phase. FPL will also continue the Long Lead Procurement, Engineering Design Modifications, and Implementation phases of the project to support the planned unit outages in 2011 and 2012. FPL is committed to approximately 95% of its long lead procurement items for the St. Lucie units and approximately 80% of its long lead procurement items for the Turkey Point units. FPL is currently performing the Engineering Design Modification Phase, and has successfully completed two of eight planned EPU outages in the Implementation Phase. FPL has also amended its contract with Bechtel, the Engineering, Procurement & Construction (EPC) vendor, for the

> St. Lucie scope of work to include a target price, better aligning FPL's and Bechtels' project goals.

FPL witness Jones listed various activities planned for each of the 2011 outages. Witness Jones also presented a graphic of the current deployment schedule for various phases of the EPU project from 2008 through 2013. The graphic shows that at this time, FPL is engaged in the LAR phase, the engineering and design phase, as well as the implementation phase. Witness Jones, in supplemental testimony, explained that FPL recently adjusted the planned outage durations between 10 and 40 days. Additionally, witness Jones stated that ". . . the start dates of the remaining St. Lucie Unit 2 and Turkey Point Unit 4 outages have been pushed back slightly, while the start date for Turkey Point Unit 3 outage has advanced slightly." He asserted the outage start dates were adjusted to minimize the overlap of nuclear and non-nuclear generation unit outages. Witness Jones also asserted that, after completing preliminary testing on St. Lucie 2, there is an increase of approximate 34 MW (29 MW after accounting for co-owners' share) due to a more efficient low pressure turbine rotor, not 20 MW (17 MW after accounting for co-owners' share) as previously anticipated.

FPL's estimate of year-ending 2011 generation construction costs was $569,779,321. The 2011 construction cost estimate included amounts for license application of $19,797,804, engineering and design of $20,251,942, permitting of $45,451, project management of $33,835,035, power block engineering and procurement of $489,873,573, and non-power block engineering and procurement of $5,975,515. Transmission expenses of $18,066,007 were estimated for activities related to main transformer, transformer cooler, and plant electrical yard upgrades. The 2011 estimated O&M expenses included $12,706,916 for feedwater heater inspection costs, for expensing obsolete materials, and for costs that do not meet FPL's capitalization policy. The estimated items going into service during 2011 include feedwater drain values, main generators, isophase bus duct modifications, and main transformer and transformer cooler upgrades. FPL's estimated base rate revenue requirement associated with completing these activities was $16,585,797.

FPL's estimate of 2011 expenses for generation construction activities increased by $29,861,426 relative to its May 2010 projections. Witness Jones asserted the increase was due in part to FPL's 2010 outage management review that moved a significant amount of work from 2010 to 2011. The largest increases by activity are $9,361,837 in licensing efforts, $10,970,418 for additional resources to support design engineering, and $9,931,219 for additional outage implementation support. FPL's estimate of 2011 transmission related expenses increased relative to its May 2010 projections by $10,227,007. The variance was due primarily to purchasing transformers and shifts in schedules. FPL's estimate of its O&M expenses increased by $8,558,723 from its May 2010 projections. FPL attributed the variance to increased scope of equipment inspections.

Witness Powers explained that the estimated 2011 project costs were compared to the May 2010 projection of 2011 recovery amounts to determine the estimated true-up amount for 2011 of $17,387,377. The requested 2011 true-up amount includes the following items: under-projected construction carrying costs of $21,157,568, under-projected O&M costs of $8,346,616 including interest, and over-projected base rate revenue requirements of $12,116,806 including carrying charges. These 2011 estimated true-up amounts were included in FPL's net total NCRC recovery request of $196,092,631.

As discussed above, OPC argued that we should find FPL was imprudent to implement a fast track approach and that a breakeven analysis is required to assess the disallowance amount. Thus, if we agree with OPC, then we should not make a finding of reasonableness, because some portion of FPL's 2011 EPU project costs and carrying charges may be determined to be imprudently incurred; therefore, the amounts subject to refund and/or disallowance will be determined in a future review using a breakeven analysis upon FPL completing the EPU project. However, as addressed above, we reject the arguments of OPC, SACE and FIPUG.

No party or audit staff witnesses identified items, activities, or costs included in FPL's 2011 project filings as unnecessary to complete the EPU project. Consistent with our findings above, our verification of FPL's calculations and estimated true-up amount, and a preponderance of the evidence in the record, we find that FPL has demonstrated the reasonableness of its requested 2011 incurred costs and appropriately determined the estimated NCRC true-up amounts.

Therefore, we approve as reasonable the estimates of 2011 costs of $587,845,328 ($558,520,431 jurisdictional) for EPU project Capital Costs, and $12,721,405 ($12,263,818 jurisdictional net of joint owner and other adjustments) for O&M Costs. The estimated 2011 true-up amount of $17,387,377 shall be used in determining the net total 2012 NCRC recovery amount.

XV. Reasonableness of 2012 EPU Projected Costs

This issue addresses FPL's request concerning the reasonableness of its 2012 EPU costs and the projected NCRC recovery amount. No testimony by parties or audit staff witnesses proposed any adjustments. We note that resolution of this issue must be consistent with the resolution of forward-looking issues addressing project feasibility and also prospective implementation of any prudence and reasonableness determinations. The only concern raised was FPL's fast track approach, which we discussed above.

FPL witness Powers provided support for the 2012 EPU project costs and methods used to determine the requested estimated true-up recovery amount. FPL witness Jones provided descriptions of the 2012 EPU project activities and costs.

Witness Powers provided an errata that identified changes to her prefiled testimony and exhibits. While there was no dispute regarding the errata, we note that the errata did not reference Exhibit 70, nor was Exhibit 70 corrected to reflect the same errata where applicable. Our staff verified that, had the schedules been updated, the summary amounts in Exhibit 70 would be consistent with FPL's errata. Therefore, for purposes of this Order, we find that reference to Exhibit 70 is as revised consistent with FPL's errata.

Witnesses Powers and Jones identified estimated 2012 EPU construction capital costs of $736,198,427 ($701,018,839 jurisdictional net of joint owner and other adjustments), and O&M costs of $5,626,844 ($5,461,197 jurisdictional net of joint owner and other adjustments). They also indicated that 2012 construction carrying costs are $67,264,453. Additionally, they present the calculation of an estimated base rate revenue requirement of $80,190,773 for phases of the EPU project that are expected to go into commercial service in 2012. In support of these amounts, FPL witness Jones stated:

> In 2012, for the EPU LAR Engineering Analysis phase, FPL will continue to support the NRC review process, including responding to NRC RAIs and interfacing with the NRC staff. The Long Lead Equipment Procurement Phase will be completed, including equipment for the modifications in the 2012 outages. The Engineering Design Modification Phase will continue with modification package preparation for the final EPU outages in 2012. Implementation will be worked for each of the three outages in 2012: the PTN Unit 3 and PSL Unit 2 spring outages, and the PTN Unit 4 fall outage. Each outage requires long lead equipment, planning, schedule integration, and the actual execution of the physical work in the plants, including extensive testing and systematic turnover to operations.

Witness Jones listed various activities planned for the each of the 2012 outages. Witness Jones also presented a graphic of the current deployment schedule for various phases of the EPU project from 2008 through 2013. FPL's projection of year-ending 2012 construction costs was $708,960,295. The 2012 generation construction cost projection included amounts for license application of $5,312,846, engineering and design of $11,091,593, permitting of $0, project management of $26,330,854, power block engineering and procurement of $665,777,875, and non-power block engineering and procurement of $447,127. The 2012 transmission construction costs are projected to be $27,238,132. The transmission costs are for replacement of transformers, transformer cooler upgrades, switchyard breaker upgrades, and line and breaker monitoring equipment. The O&M projection of $5,626,844 represents costs for performing equipment inspections, expensing obsolete materials, and expensing commodities and consumables that do not meet FPL's capitalization policy. The items projected to go in service during 2012 include transmission upgrades, main generator rotors, high pressure turbine rotors, main transformer and cooler modifications, feedwater heaters, condensate pumps, and main condensers. FPL's projected base rate revenue requirement associated with completing these activities is $80,190,773.

The requested NCRC amount for 2012 EPU project costs is $152,916,422. The projected amount consists of carrying charges of $67,264,453, O&M costs of $5,461,197 (net of participants credits and including interest), and a base rate revenue requirement of $80,190,773 for plant projected to be placed into service in 2012. These 2012 projected amounts were included in FPL's net total NCRC recovery request of $196,092,631.

We note that OPC's position on this issue is intended to be consistent with its position discussed above. As stated, OPC argued that we should find FPL was imprudent to implement a fast track approach, and that a breakeven analysis is required to assess the disallowance amount. Thus, if we agree with OPC, then we should not make a finding of reasonableness, because some portion of FPL's 2012 EPU project costs and carrying charges may be determined to be imprudently incurred; therefore, the amounts subject to refund and/or disallowance should be determined in a future review using a breakeven analysis upon FPL completing the EPU project. However, as addressed above, we reject the arguments of OPC, SACE and FIPUG.

No other concerns were raised in this matter. No party or audit staff witnesses identified items, activities, or costs included in FPL's 2012 EPU project filings as unnecessary to complete the EPU project. Consistent with our findings above, our verification of FPL's calculations and true-up amount, and a preponderance of the evidence in the record, we find that FPL has demonstrated the reasonableness of its requested projection of 2012 incurred costs and NCRC recovery amount for the EPU project. Therefore, we approve as reasonably the projected 2012 costs of $736,198,427 ($701,018,839 jurisdictional) for EPU project Capital Costs, and $5,626,844 ($5,461,197 jurisdictional net of joint owner and other adjustments) for O&M Costs. The projected 2012 amount of $152,916,422 shall be used in determining the net total 2012 NCRC recovery amount.

XVI. Willful Withholding of Required Information During the 2009 NCRC

In February 2010, an FPL employee sent a letter to the Chairman and Chief Executive Officer of FPL Group, in which certain concerns were raised about the cost performance of FPL's EPU project. This letter also expressed concerns as to the reporting of EPU cost performance to us and to FPL executive management. In March 2010, FPL retained Concentric to conduct an independent investigation of the claims raised in this employee letter. The Chief Executive Officer of Concentric, John Reed, sponsored the report containing Concentric's findings, which was completed in June 2010. The impetus for this issue is based on Concentric noting ". . . an instance where the information provided by FPL to the FPSC did not reflect the most up-to-date information as of the time it was provided to the FPSC in September 2009 . . . ." during the 2009 NCRC hearings.

Based largely on the Concentric report and a review of many documents enumerated in an appendix to this report, OPC witness Jacobs concluded that FPL should have updated its EPU cost estimate at least by the time its witness testified at the NCRC hearings in September 2009. He asserted that the cost estimate reflected in the FPL witness's May 2009 testimony in the NCRC proceeding had been superseded by the time of the 2009 hearings. Since a key driver of FPL's long-term feasibility study is the capital cost estimate of the units, witness Jacobs asserted that, the FPL witness also should have presented revised feasibility results at the 2009 hearings. Finally, OPC argued in its brief that FPL's failure to update the EPU capital cost estimate at the September 2009 hearings constituted a violation of Rule 25-6.0423, F.A.C., and concluded that "The Commission should find that FPL willfully withheld information needed for an accurate and meaningful estimate of capital costs and the related long-term feasibility analysis."

In their briefs, FIPUG and SACE endorsed OPC's arguments and position. FPL vigorously disputed OPC's contentions and offered several witnesses in opposition.

OPC witness Jacobs noted that the original EPU cost estimate was based on conceptual scoping studies. As virtually no engineering had been completed at that time, this estimate necessarily carried a high degree of uncertainty. The witness stated that during 2009, EPU project management made presentations to FPL's Executive Steering Committee (ESC) as to the status of the EPU's cost and schedule. Witness Jacobs observed that at the July 2009 ESC meeting, revised EPU cost estimates were presented for both St. Lucie and for Turkey Point; the St. Lucie estimate increased by $139.6 million over the original estimate, while the estimate for Turkey Point had increased by $160.6 million over the original estimate. He asserted that the July 2009 presentation contained a detailed line-by-line cost presentation and reflected recent efforts by FPL "to rein in Bechtel's increasing cost increases."

OPC witness Jacobs asserted that the August 2009 EPU cost estimate for both St. Lucie and Turkey Point contained in the September 2009 ESC presentation reflects a further increase, from a total cost of $1.706 billion to $1.850 billion. Consistent with the finding in the Concentric report, witness Jacobs concluded that ". . . the cost estimate submitted in FPL's prefiled testimony in May 2009 was clearly stale and should have been updated prior to or during the hearing in September 2009." He also concluded that FPL should have submitted an updated feasibility analysis that reflected an increased capital cost estimate.

Witness Jacobs disagreed with FPL's contention that at the time of the July 2009 ESC presentation there was still opportunity to eliminate scope from the EPU projects, and therefore, the amounts in the presentation were still preliminary and thus, it was premature to report them to us. His disagreement with FPL's contention was based on two claims. First, he asserted that the July 2009 amounts were the result of a detailed line-by-line cost analysis, and FPL ". . . included identification and quantification of all known reductions in scope", and "It is doubtful that additional reductions in scope would be identified at a later date." Second, he opined that FPL could have provided the latest cost estimates to us, stated that they were preliminary, then provided subsequent updated estimates as they became available and firm.

OPC witness Jacobs noted that FPL has argued that since it had directed EPU staff to "push back" against Bechtel and had not accepted Bechtel's updated estimates, FPL was not obligated to update its May 2009 testimony to incorporate the estimates from the July 2009 ESC presentation. Witness Jacobs disputed this claim because, in his opinion, "the July 2009 cost estimates include the results of FPL's initiatives to push back against Bechtel." Witness Jacobs concluded that by the time the July 2009 estimate was generated, negotiations with Bechtel were "far along."

FPL asserted that since it was still evaluating whether to self-perform certain functions or to replace Bechtel, in whole or in part, with a different EPC contractor, the July 2009 estimates were still too preliminary to rely on. In response, OPC witness Jacobs asserted that FPL nevertheless should have reported the latest numbers, accompanied by whatever caveats were deemed appropriate. Witness Jacobs also disputed FPL's claim that reporting the higher cost estimates, instead of relying on the May 2009 testimony, would undermine FPL's ability to negotiate with Bechtel. Witness Jacobs countered that "reporting a higher estimate to the Commission would not jeopardize FPL's ability to hold Bechtel to only the levels of staffing that would be required to actually perform the project as it progressed by supervising Bechtel and reviewing invoices so as to guard against paying for inefficiencies."

OPC witness Jacobs noted that an updated EPU feasibility study that incorporated increases in both the capacity of the units and capital costs was included with the July 2009 ESC presentation materials. He asserted that this submission "reinforces my conclusion that FPL had moved beyond the May 2009 information." Responding to FPL's claim that the revised feasibility information was more in the nature of a sensitivity analysis of the prior feasibility study, witness Jacobs stated that what the calculations are called does not alter their significance that the new analysis reflects the impacts of changes in key variables. Witness Jacobs concluded that FPL's NCRC witness should have updated the EPU cost estimates and submitted an updated feasibility study at the September 2009 hearings.

OPC witness Jacobs testified that based on information he reviewed, FPL senior management had decided during the August-September 2009 period that it was not necessary to update the EPU cost estimates for the September 2009 hearings. Witness Jacobs reviewed an email from Rajiv Kundalkar, the FPL witness who sponsored the testimony containing the EPU cost estimate at the 2009 hearings, to FPL's Chief Nuclear Officer. Witness Jacobs believes the email implies that the FPL witness was considering updating his testimony. From this, witness Jacobs acknowledged that during Mr. Kundalkar's deposition, Mr. Kundalkar denied that the email in question related to his potentially updating his testimony. Nevertheless, witness Jacobs reiterated his view that FPL should have updated this testimony to reflect updated EPU capital costs by the September 2009 hearings.

Witness Jacobs concluded that FPL failed to provide us with the most current information regarding EPU capital costs during the September 2009 hearings because it chose not to revise FPL witness Kundalkar's testimony incorporating newer cost estimates that became available between May 2009 and the time of the 2009 hearings. Moreover, he contends that since capital costs are a major cost driver in the EPU feasibility analysis, FPL should have updated its feasibility analysis to incorporate the more recent cost estimate.

FPL offered testimony of three witnesses on this issue: witnesses Olivera, Jones and Stall. Witness Olivera was adamant that the company ". . . did not withhold information that the Commission needed to make an informed decision during the September 2009 hearings in Docket No. 090009-EI." He asserted that as of September 2009, the more recent cost forecast information had not been thoroughly vetted or accepted by company management, and thus was not sufficiently reliable to warrant a revision in the EPU's estimated total in-service costs. Witness Olivera stated that the review efforts to support a project cost revision were not completed until April 2010, for inclusion in FPL's May 2010 NCRC filing.

During cross-examination, witness Olivera was asked whether FPL had withheld information that it was required to submit either by statute or rule. He responded in the negative, explaining that FPL had received an estimate from its contractor that reflected increases in required work hours for the EPU projects, but FPL had not completed its validation of the estimates provided by Bechtel. Witness Olivera stated that numerous options were under consideration at the time, including replacing Bechtel as the EPC or breaking the project up between multiple vendors. Witness Olivera testified: "I think you expect us when we come in here that we present to you a number that is fully vetted, that we stand by it, that we have spent the time scrubbing." Witness Olivera acknowledged that he was involved in the decision not to modify Mr. Kundalkar's testimony and he further stated that ". . . and I told them, look, when we have – when we fully vet the information, when we understand whether this is accurate or not, we'll go to the Commission."

FPL witness Jones testified that throughout 2009, the company was focused on projected staffing requirements that were provided by the EPU EPC to commence with engineering for the Plant Change Modifications. The EPC's proposed staffing levels provided to FPL in early 2009 would have resulted in an increase in the costs over original estimates. In responding to these estimates, FPL challenged these projections and required Bechtel to justify each requested position as being necessary for that stage of the EPU project. Approval was granted for only those positions "appropriate for that stage of the project, including EPC management and engineering staff."

FPL witness Jones stated that during the second quarter of 2009, the EPU project team "determined that there was a need to more aggressively explore and implement ways to test, validate, and report cost projection information such as that which the Company had begun to receive from its EPC vendor, especially for the out-years of the Uprate project." In addition to direction from executive management to continue challenging Bechtel's estimates, the EPU team was directed to consider use of alternative EPC vendors for part of the work, and to retain third-party estimating support "to assist in advancing the project cost estimate and to use as a tool in challenging vendor estimates." After several negotiations with the EPC and challenges by the EPU site management and EPU executive management, the EPC projected staffing levels were decreased.

FPL witness Jones testified that fluctuating vendor proposals were reflected in the EPU project cost reports and thus total project completed cost varied from month to month. Witness Jones further explains these fluctuations:

> The project cost forecasts represent a snapshot of current trends but do not necessarily represent everything known about the project. For example, while a particular month's forecast may have incorporated a recent EPC vendor staffing estimate, it would not have reflected the fact that EPU management was considering EPC vendor alternatives with the potential to reduce costs. Due to the extensive project management activity in mid-to-late 2009, and considerations that put both upward and downward pressure on potential total project costs, FPL had an insufficient basis upon which to revise its non-binding cost estimate for the EPU project.

FPL witness Stall testified that through September 2009 and into 2010, key factors affecting the EPU total project cost estimate were in flux. As noted above, FPL had received cost estimates from its EPC vendor that were unacceptable to EPU management. The witness noted that FPL was only able to revise its non-binding cost estimate after "significant challenging, vetting, project scope refinement, and the consideration of alternatives to FPL's EPC vendor." This revision was completed shortly prior to filing its NCRC testimony on May 3, 2010.

FPL witness Stall disagreed with the finding in the Concentric report that FPL should have revised its testimony to incorporate a revised EPU cost estimate by the time of the September 2009 NCRC hearings. He countered that FPL's May 2009 testimony was not inaccurate, and was neither necessary nor appropriate to revise that testimony. The witness noted that as of September 2009, the EPU project scope was growing, which would result in increased total project cost. However, he asserted that it appeared there were areas where further scope and cost reductions were possible.

FPL witness Stall noted that FPL received from its EPC vendor estimated labor costs that exceeded the level provided during the earlier bid process. He contended that these cost projections had not been fully vetted or challenged by FPL by the time of the 2009 hearings. Options were under consideration, including self-performing some or all of the EPU work, or possibly hiring an alternative EPC vendor. Witness Stall asserted that since there was the potential for both cost increases and decreases during the July-September 2009 period, FPL could not provide a reliable EPU cost update by the September 2009 hearings.

Witness Stall opined that differences of opinion can exist as to whether the EPU cost estimate available as of September 2009 was suitable for public release at that time. He believes, however, that the existence of disagreement does not "demonstrate any inappropriate action or intentional withholding of information by FPL. To the contrary, it demonstrates FPL's desire to provide reliable, fully vetted information to this Commission." Moreover, he noted that Concentric and FPL are in accord that the decision to continue with the EPU project was best for FPL's customers, and that no costs were imprudently incurred.

During cross-examination witness Stall was asked what the term "fully vetted" means within FPL's processes. He responded:

> . . . we have process that we follow at the company for major capital projects, for investor information releases, any information that is going to be used in a business case to make financial decisions or be released externally to external stakeholders, whether it's the Public Service Commission in this case, the Nuclear Regulatory Commission, or the SEC. And that process is basically one in which the staff, in this case the engineers on the project management team present in a series of reviews to executive management updates as you have seen in these presentations.
>
> And we challenge that, and we push back, and we ultimately come to a decision point where we approve what they are presenting, and it is formally approved at the executive steering committee level. And only then is that information considered approved by the company. It has been fully vetted or

challenged and approved in order to be released to an external stakeholder, in this case the Public Service Commission.

FPL witness Stall was subsequently asked if someone from Concentric had met with any members of the ESC, to which he responded "no." He stated that had this occurred, Concentric would, first, have gained perspective as to how information was fully vetted before it is released externally; second, insight would have been gained regarding prior FPL business interactions with Bechtel and personal experiences on other projects.

In his rebuttal testimony, FPL witness Stall countered OPC witness Jacobs' assertion that FPL's efforts to challenge, vet, undertake project refinement and consider alternatives to FPL's EPC vendor, had been completed by September 2009. In February 2009, FPL had concerns over Bechtel's EPU cost estimates, and directed its controls group to have Bechtel reduce these estimates. After several months with limited success, Bechtel executives were summoned to a meeting in July 2009 at FPL headquarters. At that time, Bechtel reduced its estimates, giving FPL the sense that further progress could be made with Bechtel. Witness Stall also noted that the September 2009 Executive Steering Committee presentation indicated "that there was only a ten percent certainty around implementation costs."

FPL witness Stall also disputed OPC witness Jacobs' statement that disclosure of Bechtel's estimates at the September 2009 hearings would not affect negotiations between FPL and Bechtel. He asserted that reporting the Bechtel estimates could be seen as tacit approval of them, or that FPL afforded them some validity. In addition, witness Stall argued that witness Jacobs is incorrect when he claims that the cost estimates in the July 25, 2009 forecast reflected all efforts to "push back" on Bechtel's amounts. Witness Stall stated that the July 25, 2009 numbers only capture Bechtel's initial response to FPL's "push back" efforts. In our staff's deposition of OPC witness Jacobs, he essentially conceded this point.

We find that to resolve this compound issue, there are three points to be addressed:

(1) Did FPL willfully fail to provide updated EPU cost estimates by the time of the September 2009 NCRC hearings?

(2) Was FPL required by Rule 25-6.0423, F.A.C., to update its EPU cost estimates by the time of the September 2009 NCRC hearings?

(3) Did we need updated EPU cost information in order to make an informed decision at the September 2009 NCRC hearings?

We address each point individually.

(1) Willfully Withholding: As discussed above, FPL admits it consciously made this decision not to update the testimony of FPL witness Kundalkar filed in May 2009. Because it had not completed "scrubbing" the numbers received from Bechtel, EPU cost estimates during 2009 were in flux, and FPL had not concluded vetting the revised EPU cost forecasts. FPL

witnesses Olivera and Stall testified that it is FPL's practice to perform and complete this vetting prior to external release of such information.

OPC acknowledges in its position statement that FPL consciously decided not to provide EPU cost updates, but apparently proceeds to equate "consciously withholding" with "willfully withholding." Similarly, in its brief, OPC asserts that "FPL knew, but intentionally withheld, information demonstrating that the cost of the project had substantially increased."

We find that FPL "consciously" or "intentionally" decided not to update witness Kundalkar's testimony. However, for the reasons stated below, we do not find that FPL willfully withheld information we needed to make an informed decision.

(2.) Required to update by Rule 25-6.0423, F.A.C.: FPL acknowledged in its brief that this rule obligates it to provide information on nuclear project costs in March and May of each year, and to file a feasibility analysis in May of each year. FPL asserted that it ". . . fully complied with these obligations; presenting the best information it had available at the time of these filings and at the September 2009 hearing."

OPC noted that Rule 25-6.0423(8)(f), F.A.C., requires a utility to submit annually an estimate of a nuclear projects in-service capital costs, and that Rule 25-6.0423(5)(c)5, F.A.C., requires it submit annually a feasibility analysis. OPC contended that "A rule that a utility can ignore, or to which a utility can respond with outdated or superseded information, is no rule at all. . . . FPL consciously and deliberately chose to withhold information necessary to comply with the rule."

We respectfully disagree with OPC's conclusion that FPL consciously and deliberately chose to withhold information necessary to comply with the rule. The rules cited provide for annual filings; beyond that, they are silent. In general, we agree with OPC witness Jacobs' assertion during his deposition that ". . . it's the inherent responsibility of the utility to provide the most recent information to the Commission to give the Commission the best information possible to make an informed decision." However, witness Jacobs also agreed that he had not provided in his testimony any guidance to us or FPL as to the disclosure of preliminary cost data. We find that if reliable updated cost data is available prior to an NCRC hearing, it is reasonable to expect that it will be presented to us for our consideration. However, we note that while FPL acknowledged that cost estimates for aspects of the EPU project had increased during 2009, the company had not completed validating and vetting these estimates, which is standard company practice prior to external releases of information. Since the information in question (EPU total project cost estimate) had not fully completed FPL's vetting process at the time of the September 2009 hearings, we find that FPL did not willfully withhold necessary information. We note that utilities are charged with an implicit obligation to present this Commission as the trier of fact with reliable, vetted information necessary for us to make an informed decision.

(3) Whether we needed updated information to make an informed decision: FPL argued in its brief that whether or not FPL had updated its total project costs, it would have had no bearing on our determination regarding the prudence of 2008 EPU costs, or the reasonableness of 2009 and 2010 costs. At hearing, OPC witness Jacobs confirmed that decisions regarding costs

already incurred were unaffected. The cost estimate that OPC asserted should have been updated pertains to estimates of the project's total completed costs, but this amount had no bearing on our decisions regarding costs incurred for 2008, 2009, or 2010. At hearing the following exchange occurred between a fellow Commissioner and witness Jacobs:

> Q. Future estimated costs?
> A. Future, yes. Total, total costs, total estimated costs.
> Q. Not costs incurred.
> A. That's right, not costs incurred.

The only decision that possibly could have been affected would have been regarding the feasibility of continuing the EPU project. However, FPL noted in its brief that:

> FPL performed a sensitivity analysis in July 2009 of potential cost increases as well as potential unit output increases, and to determine whether the project would still be cost-effective for customers using these assumptions. The sensitivity analysis demonstrated that, even assuming higher costs *without* the potential for increased output, the EPU project remained solidly cost-effective for FPL's customers.

OPC witness Jacob agreed that the July 2009 sensitivity analysis shows that the EPU project remained economically feasible even at the higher cost estimates.

We find that no necessary information was withheld from us that we needed to make an informed decision at the time of the September 2009 hearing.

Therefore, we find that FPL did not willfully withhold information concerning the estimated capital costs and its related long-term feasibility of the EPU project as required by Rule 25-6.0423, F.A.C., and that no information was withheld that we needed to make an informed decision at the time of the September 2009 hearing. However, we find that to the extent that reliable changes to the estimated total project cost are known prior to an NCRC hearing, it shall be reasonable to expect that this information will be presented to us for our consideration. We find that FPL shall continue to provide to us with validated, reliable updates of total project cost estimates as they are available.

XVII. Total Jurisdictional Amount to be Included in Establishing FPL's 2012 Capacity Cost Recovery Clause Factor

This issue is a fall-out issue that reflects decisions on all prior issues. Based upon our decisions above we approve a total jurisdictional amount of $196,088,824 for the net total 2012 NCRC recovery amount. This amount shall be used in establishing FPL's 2012 Capacity Cost Recovery Clause factor.

Progress Energy Florida, Inc.

XVIII. 2011 Annual Detailed Analysis of the Long-term Feasibility of Completing the Levy Units 1 & 2 Project

This issue addresses PEF's detailed long-term feasibility analysis of continuing construction on the LNP as required by Rule 25-6.0423, F.A.C., and Order No. PSC-08-0518-FOF-EI.

In an effort to mitigate the economic risks associated with the long lead-time and high capital costs associated with nuclear power plants, the Florida Legislature enacted Sections 366.93 and 403.519(4), F.S., during the 2006 legislative session. Section 366.93(2), F.S., requires to us establish, by rule, alternative cost recovery mechanisms for the recovery of costs incurred in the siting, design, licensing, and construction of a nuclear power plant. We adopted Rule 25-6.0423, F.A.C., to satisfy the requirements of Section 366.93(2), F.S. Rule 25-6.0423(5)(c)5, F.A.C., states:

> By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long term feasibility of completing the power plant.

In Order No. PSC-08-0518-FOF-EI, we provided specific guidance regarding the requirements necessary for PEF to satisfy Rule 25-6.0423(5)(c)5, F.A.C. The Order reads as follows:

> ORDERED that Progress Energy Florida, Inc. shall provide a long-term feasibility analysis as part of its annual cost recovery process which, in this case, shall also include updated fuel forecasts, environmental forecasts, non-binding capital cost estimates, and information regarding discussions pertaining to joint ownership.

Additionally, the Order contains the following language lending insight to our intent regarding the long-term feasibility of PEF's LNP:

> We will review the continued feasibility of Levy Units 1 and 2 during its annual nuclear cost recovery proceedings; thus, providing the appropriate checks and balances to ensure that the construction of the nuclear units continues to be in the best interest of PEF' s ratepayers.

A. Required Elements

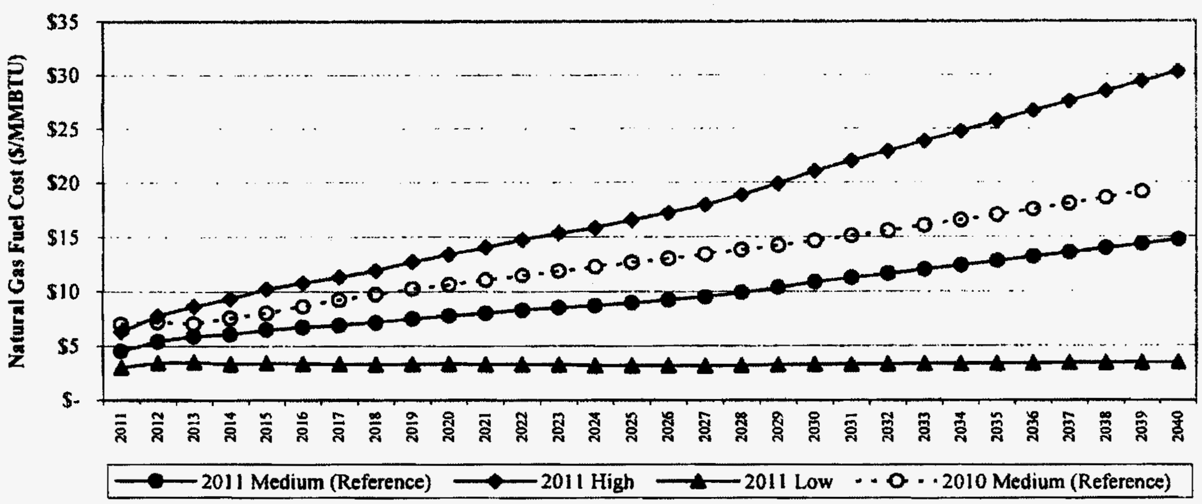
We find that PEF satisfied the submission requirements as outlined in Order No. PSC-08-0518-FOF-EI, with the information it has provided. We find that the forecasts, cost estimates, and analyses are necessary filing requirements to assess PEF's 2010 LNP feasibility analysis. In addition, we reviewed regulatory and technical aspects of the project. These elements provide a broad perspective for our findings regarding the approval or denial of PEF's detailed long-term feasibility analysis.

B. Economic Feasibility

1. Updated Fuel Forecasts

PEF's updated fuel price forecast was developed from the same industry-accepted sources PEF has used since the need determination proceeding. The table below depicts the medium range price forecasts of natural gas used from the 2010 NCRC proceeding and this year's filing for low, mid-reference, and high ranges used to support PEF's feasibility analysis. We note that the mid-reference natural gas price forecast is slightly less than the forecast presented last year.

PEF Gas Price Forecasts
($/MMBtu)

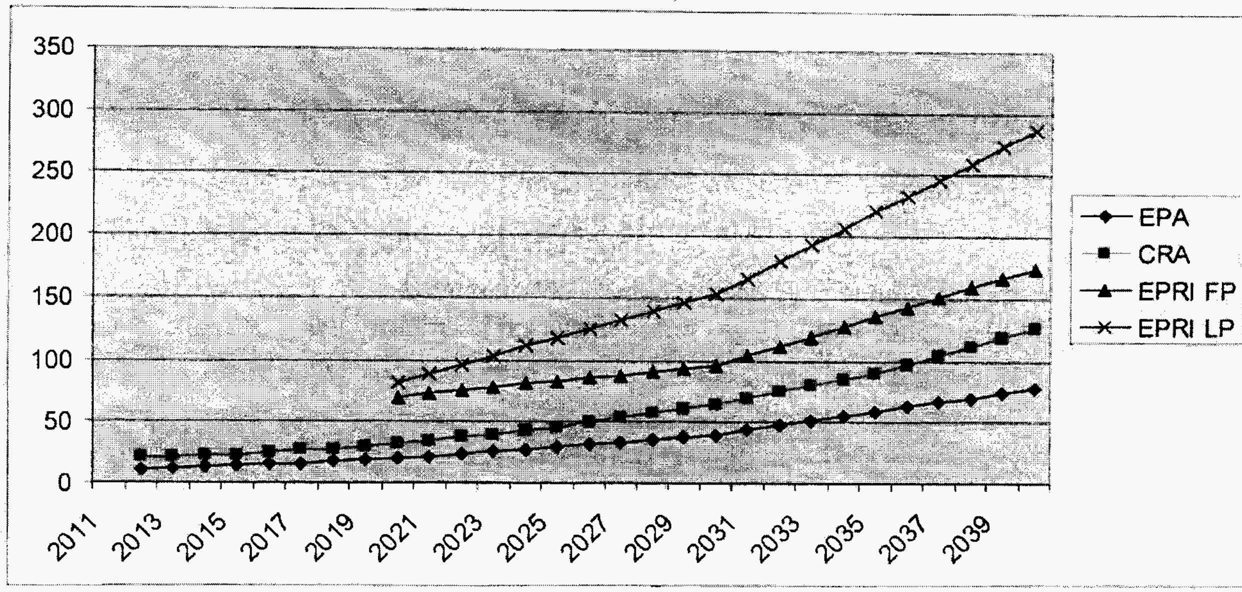


None of the parties contested the accuracy or credibility of PEF's fuel forecast. We note that PEF, as in past years, continued to use multiple fuel price forecasts in its analysis. The range of forecast prices provides an expectation that actual prices will be included within the range, thereby lending credibility to PEF's cost-effectiveness analysis. We find that it is reasonable to accept PEF's updated fuel cost data in this proceeding.

2. Environmental Forecasts

Likewise, the updated environmental cost forecasts PEF submitted were developed from the same industry-accepted sources PEF has used since the need determination proceeding. The table below depicts the price forecasts for four of the five carbon dioxide (CO_2) emission scenarios used in PEF's cost-effectiveness analysis. The fifth scenario used a CO_2 cost of $0.00.

2011 PEF CO_2 Cost Forecasts
($/Ton)

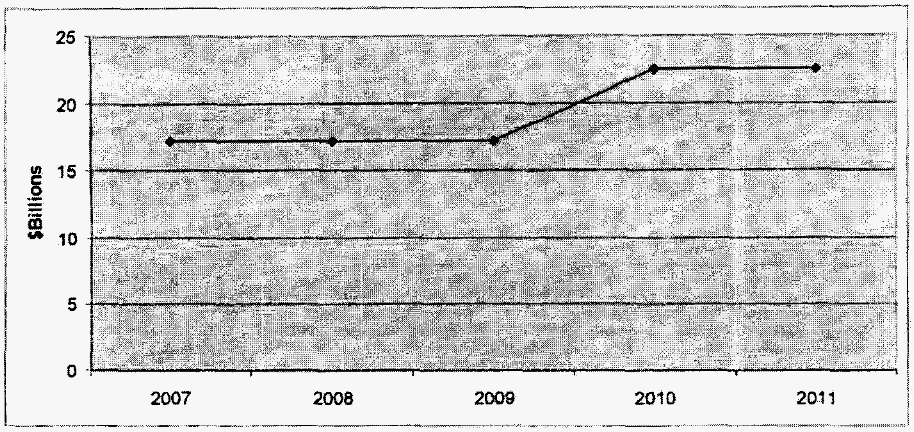


As with the fuel cost forecast, none of the parties contested the accuracy or credibility of the emissions cost forecasts PEF submitted. We also note that PEF, as in past years, continued to use multiple price forecasts for CO_2 emissions in its analysis. The range of forecast prices provides an expectation that actual prices will be included within the range, thereby lending credibility to PEF's cost-effectiveness analysis. We find it is reasonable to accept PEF's updated fuel cost data in this proceeding.

3. Project Cost Estimate

PEF estimates that the cost of the LNP is $22.5 billion, which includes about $5 billion in carrying costs and about $616 million in sunk costs. This is the same total cost estimate as PEF provided in the 2010 NCRC proceeding. The table below depicts PEF's cost estimates each year since the 2007 need determination proceeding.

PEF's LNP Cost Estimate
Including AFUDC and Sunk Cost



While some intervenors took exception to PEF's cost estimate, no evidence was presented to refute or change PEF's estimate. PEF used its current project cost estimate in conducting its cost-effectiveness analysis. Results of the analysis demonstrate that the cost-effectiveness of the project has declined in comparison with the competing plan without nuclear generation. We find PEF's cost estimate is reasonable.

4. Project Cost-Effectiveness

The CPVRR economic analysis PEF submitted indicates that the LNP is economically viable and has the potential to provide PEF and its customers with fuel and environmental cost savings over the life of the project. PEF witness Elnitsky testified that the qualitative feasibility analysis of the enterprise risk facing the LNP reveals some changes in the enterprise risk since last year but no dramatic increase or decrease in the uncertainty associated with the risk facing the project and no fundamental changes in these risks that indicate a need to either accelerate or cancel the LNP at this time. The table below shows the results of the updated CPVRR analysis.

PEF Summary CPVRR Review for 2011 NCRC Filing

Economic Results Summary Table (NCRC '11 Study)										
Fuel Sensitivities				**CapEx Sensitivities**						
Base Capital Reference Case	Low Fuel Reference	Mid Fuel Reference	High Fuel Reference	Mid Fuel Reference Case	LNP CapEx (15%)	LNP CapEx (5%)	Mid Fuel Reference	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
NCRC APR '10: 100% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate										
No CO_2	($12,366)	($3,714)	$8,269	No CO_2	($2,042)	($3,182)	($3,714)	($4,322)	($5,461)	($6,601)
EPA WM CO_2	($8,172)	$936	$12,549	EPA WM CO_2	$2,534	$1,394	$936	$254	($886)	($2,026)
CRA WM CO_2	($5,579)	$3,715	$15,306	CRA WM CO_2	$5,380	$4,240	$3,715	$3,100	$1,960	$821
EPRI Full CO_2	($2,986)	$6,446	$18,219	EPRI Full CO_2	$8,125	$6,985	$6,446	$5,846	$4,706	$3,566
EPRI Ltd CO_2	$2,527	$12,062	$24,401	EPRI Ltd CO_2	$13,748	$12,608	$12,062	$11,468	$10,328	$9,188
NCRC APR '10: 80% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate										
No CO_2	($10,039)	($3,100)	$6,567	No CO_2	($1,762)	($2,654)	($3,100)	($3,547)	($4,439)	($5,331)
EPA WM CO_2	($6,755)	$399	$9,897	EPA WM CO_2	$1,737	$845	$399	($47)	($939)	($1,831)
CRA WM CO_2	($4,715)	$2,567	$11,994	CRA WM CO_2	$3,906	$3,013	$2,567	$2,121	$1,229	$337
EPRI Full CO_2	($2,651)	$4,700	$14,208	EPRI Full CO_2	$6,038	$5,146	$4,700	$4,254	$3,362	$2,470
EPRI Ltd CO_2	$1,663	$9,099	$18,929	EPRI Ltd CO_2	$10,437	$9,545	$9,099	$8,653	$7,761	$6,869
NCRC APR '10: 50% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate										
No CO_2	($7,056)	($2,592)	$3,624	No CO_2	($1,746)	($2,310)	($2,592)	($2,874)	($3,438)	($4,002)
EPA WM CO_2	($4,947)	($366)	$5,687	EPA WM CO_2	$480	($84)	($366)	($648)	($1,212)	($1,776)
CRA WM CO_2	($3,640)	$1,053	$7,030	CRA WM CO_2	$1,899	$1,335	$1,053	$771	$207	($358)
EPRI Full CO_2	($2,343)	$2,425	$8,412	EPRI Full CO_2	$3,272	$2,707	$2,425	$2,143	$1,579	$1,015
EPRI Ltd CO_2	$420	$5,262	$11,499	EPRI Ltd CO_2	$6,108	$5,544	$5,262	$4,980	$4,415	$3,851

Note: A positive number indicates the LNP would be more cost-effective than the non-nuclear alternative.
Conversely, a negative number indicates the LNP would be less cost-effective than the non-nuclear alternative

As shown in the table, the analysis results are that 10 of 15 fuel sensitivity scenarios, at 100 percent ownership, show savings over the non-nuclear alternative. At 80 percent ownership, the results are similar, and at 50 percent ownership, 9 of 15 scenarios show savings. The capital cost scenarios show similar results with each of the 3 ownership cases showing savings in well above 50 percent of the scenarios.

We note that the CPVRR analysis PEF submitted this year shows the LNP is less cost-effective than last year's analysis; however, the analysis still shows the LNP is cost-effective. It has gone down due to lower gas costs, but it is still positive.

OPC, joined by PCS Phosphate, argued that we should reject PEF's feasibility analysis because of the downward trend in the price forecast for natural gas and the lack of legislation on carbon dioxide emissions. They claim the downward trend of these risks "are causing the Levy Project to become less and less cost effective."

OPC compared PEF's 2010 and 2011 cost-effectiveness analyses to demonstrate a decline. Having made that comparison, OPC contended:

> The annual CPVRR analyses performed by PEF are not apples-to-apples comparisons of cost effectiveness. Each subsequent CPVRR analysis does not

> allow effective comparison with the 2008 need determination CPVRR analysis nor allow the Commission to determine whether the Levy Project is becoming more or less cost effective.

OPC appears to negate the value of its own 2010 to 2011 comparison. While we agree with OPC that this year's CPVRR analysis shows the LNP is less cost-effective than in previous years, we do not find that the CPVRR analysis we have relied upon since the need determination is ineffective.

SACE argued that PEF's CPVRR economic analysis demonstrates the LNP is not economically feasible due to the results of the low fuel reference scenarios. However, we note that our position, as established last year, was: "We find that the low fuel reference scenario should be discounted because it assumes natural gas prices to remain less than \$5.00/MMBtu over the next 30 years."[23] The low fuel scenario in the 2011 analysis also has prices below \$5.00/MMBtu over 30 years. We note that the only scenario not cost-effective for the medium fuel is the zero cost for CO_2. The project remains cost-effective in the other 4 medium fuel scenarios at 100 percent ownership. While no one can precisely predict the future cost of natural gas or CO_2 emission costs, it is clear that nuclear power will reduce both of these costs from what they would otherwise have been.

OPC went to some length in attempting to demonstrate PEF failed to fully consider the negative impact of lower prices for natural gas and the lack of any legislation setting a cost on carbon dioxide emissions. SACE, on the other hand, highlights PEF's careful consideration of these topics, but disagrees with PEF's conclusions. The end result of the discussion by several intervenors is that the project is not cost-effective.

Despite contentions by intervenors that PEF's cost-effectiveness analysis is deficient, we find otherwise. Much of what intervenors characterize as lack of viability is due to responses from PEF witnesses acknowledging an intervenor-proposed hypothetical situation is possible. No attempt was made to determine what is probable. We find that the CPVRR analysis methodology PEF has consistently used, and which we have consistently accepted as a demonstration of cost-effectiveness, is reasonable. Therefore, we find that the LNP is economically feasible.

C. Regulatory Feasibility

PEF acknowledged continued uncertainties in the regulation of emissions and national energy policy, NRC approval of the COL, impacts of the nuclear disaster in Japan, and merger approval with Duke Energy, to name a few. PEF witness Elnitsky discussed these uncertainties in depth which are summarized as follows:

> All in all, little has changed in a year. There has been no dramatic increase in or decrease in the uncertainty associated with the multiple factors that impact the

[23] Order No. PSC-11-0095-FOF-EI, issued February 2, 2011, in Docket 100009, In re: Nuclear Cost Recovery Clause, p. 24.

> LNP. There also have been no evident fundamental changes in the project's enterprise risks that either suggest moving forward more quickly with the LNP or cancelling the project at this time.

Several intervenors mentioned concerns about some of the regulatory uncertainties. We find that PEF has an effective process in place to provide its management with an ongoing, detailed analysis of the uncertainties and risks that could impact its licensing, approval, and certifications necessary for project success, and that the project is feasible from a regulatory standpoint.

D. Technical Feasibility

Closely related to regulatory issues are some technical issues with the Westinghouse AP1000 technology planned for the LNP. First is the NRC certification of the latest design change, Revision 19, to the AP1000. This process must be completed prior to a Combined Operating License being issued. Witness Elnitsky testified that the approval process for the design change is progressing well. In September 2011, the NRC staff made their final recommendation for approval of the revision to the AP1000 design. The NRC commissioners are expected to vote on that recommendation in November. Assuming the recommendation is adopted in November, the rule change would become effective in February, 2012. In addition, witness Elnitsky noted that the NRC schedule should have no impact on the LNP schedule.

The intervenors expressed skepticism that PEF's new nuclear units would remain safe after such events as the Japanese Fukushima Daiichi nuclear plant disaster. To that concern, PEF witness Elnitsky explained that the AP1000 is a passive design that does not rely on diesel generators for core cooling as the damaged Japanese plants did. He also noted that the Japanese units were located in a high seismic risk area while the LNP will be built in a low seismic risk area. In summary on this topic, witness Elnitsky testified:

> These potential risks were taken into account in our qualitative feasibility analysis for the LNP. However, there is no reason to believe now that the regulatory approvals for the AP1000 and the COLAs will not be obtained as a result of recent events in Japan.

While intervenors expressed doubt about the safety of nuclear units since the Japanese disaster, we find that the evidence supports the LNP being viewed as technically feasible.

E. Funding Feasibility

PEF witness Elnitsky testified as to the outlook for PEF's access to capital:

> The rating agencies and equity analysts have generally responded favorably to the announced merger proposal. Upon announcement of the proposed merger, Fitch Ratings ("Fitch") affirmed the ratings of Progress Energy and the Company and indicated the rating outlook was stable. Moody's Investors Service ("Moody's") also affirmed the Company's credit ratings and placed them on stable outlook.

> Standard & Poor's ("S&P") placed Progress Energy and the Company on Creditwatch with positive implications in response to the announcement of the proposed merger. Moody's further commented that the proposed merger better positions the combined company to undertake the construction of new nuclear generation.

The other parties did not contest witness Elnitsky's testimony.

We find PEF's current access to capital markets serves as confirmation of PEF's continued funding feasibility.

F. Joint Ownership

OPC raised a concern about the current lack of any joint owners: "OPC asserts that joint ownership is and remains a preeminent critical risk which must be mitigated . . ." OPC further observes that the Florida Municipal Power Agency has signed a letter of intent to purchase a share of a nuclear project in South Carolina.

FIPUG argued, "Further, PEF has been unable to secure any joint participation in the project, another indication of lack of viability at this time. It appears that the viability of this project is in grave doubt." FIPUG further contends that the lack of any partners is one of several factors making the project not feasible at this point.

In contrast, PEF witness Elnitsky testified that PEF could go forward with the LNP without joint ownership. He also pointed out that the negative side of joint ownership is the loss of benefits to PEF ratepayers. Witness Elnitsky explained that joint ownership agreements entered into by some municipal utilities reflect that new nuclear generation was a prudent generation option for Florida. However, witness Elnitsky continued, these agreements appear to be non-binding and not firm commitments: "Further, there is no indication that these municipal electric utilities are no longer interested in joint ownership participation in the LNP at this time."

We find by the preponderance of the evidence that joint ownership is not a project feasibility concern at this time.

G. Conclusion

PEF presented evidence that examined the economic, regulatory, and technical factors impacting the long-term feasibility of the LNP that demonstrated the project remains feasible. In addition, PEF provided updated fuel, environmental, and project costs forecasts as requested by us. Therefore, we accept and approve PEF's long-term feasibility analysis of the LNP.

XIX. LNP Estimated Total Cost

OPC argued that PEF's cost estimate is "inscrutable," and not reasonable. OPC based these claims on PEF's filings with the Security and Exchange Commission, which did not include the current commercial operations date (COD) and PEF planning documents that examine PEF's options, including a later COD. A later COD, OPC contended, would result in increased cost.

FIPUG contended a lack of competent, substantial evidence and the uncertainty associated with the LNP make PEF's cost estimate unreasonable.

PEF witnesses Elnitsky and Foster testified that the total estimated cost for the LNP, including AFUDC, approximately $5 billion, and sunk costs of $616 million, was approximately $22.5 billion. PEF argued that no evidence or cross examination questions contested the creation, amount, or reasonableness of its LNP cost estimate. PEF insisted that the issue should be based on the undisputed testimony of PEF witnesses.

We note that PEF's cost estimate is unchanged since the 2010 NCRC proceeding, as previously mentioned above. We find that neither OPC's nor FIPUG's arguments are persuasive and accept PEF's cost estimate.

XX. LNP Estimated Commercial Operation Dates

OPC argued that it is increasingly unlikely that the LNP will begin commercial service by 2021/2022. OPC pointed to PEF's filings with the Security and Exchange Commission (SEC) that did not include the current COD and PEF planning documents that examine PEF's options, including a later COD, as evidence that PEF was actually planning on a COD of 2027/2029.

FIPUG contended a lack of competent, substantial evidence and the uncertainty associated with the Levy project make PEF's current estimated COD unreasonable.

PEF witness Elnitsky testified that the current estimated in-service dates for the Levy units were 2021 and 2022. In addition, both the March 2011 Levy Integrated Program Plan (IPP) and a detailed project schedule for Levy show that PEF plans for the units to enter service in 2021 and 2022.

We reject OPC's argument. We view the lack of a COD on a SEC filing as speculative in nature. It is well established in the record and that PEF publicly stating the 2021 and 2022 CODs before the NRC and the PSC. Falsifying information in either of these forums would likely bring significant consequences. Instead of accepting PEF's statements of COD in many official documents, OPC speculated that the omission of a COD in SEC filings was to allow PEF to plan on a later COD without misleading those who rely on SEC filings for financial investments or other purposes.

Equally unpersuasive was OPC's contention that PEF's planning documents indicated planning underway for a later COD. A company's review of all available options for a long-term, complex project is routine procedure in the business world. Such options might well include earlier or later extremes of commercial operations date. During cross examination about a PEF Senior Management Committee (SMC) retreat to discuss near-term decisions and longer-term strategies, PEF witness Elnitsky explained, "The purpose of this analysis, again, was to stress our thinking about how we would respond to some of these future events if they were, in fact, to occur and what that would mean in terms of our options around resource planning." OPC's witness Jacobs also testified about the management review:

> Q: You would agree that PEF's senior management reviewed and approved the LNP IPP as of March 29, 2011, which shows COD 2021 and 2022, and the company's commitment to fund the Levy nuclear project several months after the scenario analyses were reviewed?
>
> A: That's correct.

Failure by senior managers to consider all reasonable possibilities likely would be viewed as irresponsible by both regulators and PEF's board of directors. PEF witness Elnitsky testified that PEF's senior managers conducted such a review of long-term strategic considerations. Only after that review was completed and a plan was approved did senior managers commit to that plan. The resulting March 2011 IPP for the LNP that each SMC member signed commits PEF to commercial operational dates of 2021 and 2022. Likewise, we find FIPUG's contention that evidence PEF submitted was neither competent nor substantial, is not convincing.

Therefore we note that PEF has used the 2021/2022 dates in its annual feasibility analyses for 2010 and 2011, as previously discussed above. We accept PEF's estimated commercial operations date for Levy Units 1 & 2 as 2021 and 2022, respectively.

<u>XXI. PEF's Intent to Construct LNP</u>

This issue addresses whether PEF's current activities relating to the LNP qualify as siting, design, licensing and construction of a nuclear power plant as contemplated by Section 366.93, F.S.

In Docket No. 100009-EI, we were presented a similar issue for consideration. The only difference between the issue presented in 100009-EI and the one identified in the current docket is the inclusion of the words "to date."

As stated in Order No. PSC-11-0095-FOF-EI in Docket No. 100009-EI, the intervenors (OPC, FIPUG, SACE and PCS Phosphate) contended that:

> PEF's actions do not comport with the purpose of the statute, which is to promote investment in nuclear energy through the siting and ultimate construction of nuclear power plants. They argue that PEF has decided to suspend all work and major capital expenditures on the LNP except that necessary to continue its attempt at obtaining a COL from the Nuclear Regulatory Commission (NRC). They further argue that the utility is not engaging in the siting, design, licensing, and construction of a nuclear power plant. Also, the Intervenors assert that no PEF witness could testify that the LNP project would be built, thus, there is uncertainty whether the nuclear plants would be constructed. Moreover, the Intervenors contend that today, the project is on hold for at least 5 years and any safety related construction cannot be undertaken until at least three steps occur: (1) the NRC must issue the COL; (2) The PGN Board must vote to authorize

> management to give notice to the EPC contractor to restart the work, and (3) the notice must then be given to the contractor. PEF has testified that this process will not likely take place until 2013 at the earliest, if at all.

(Order No. PSC-11-0095-FOF-EI, pp. 10-11) As resolution of the intervenors' contentions, we found:

> In analyzing this issue, the main question for us to consider is whether a utility must engage in the siting, design, licensing and construction of nuclear power plant activities simultaneously in order to meet the statutory requirements under Section 366.93, F.S.
>
> Based upon our analysis of the applicable statute, our prior decisions, and prior Florida case law, we do not find that a utility must engage in the siting, design, licensing, and construction of nuclear power plant activities simultaneously in order to meet the statutory requirements under Section 366.93, F.S. We find that a utility must continue to demonstrate its intent to build the nuclear power plant for which it seeks advance recovery of costs to be in compliance with Section 366.93, F.S.

(Order No. PSC-11-0095-FOF-EI, p. 9) Additionally, we found:

> We find that PEF continues to demonstrate its intent to build the plant. PEF amended its engineering, procurement and construction (EPC) contract to build the plant. ..... PEF's witnesses testified that the utility will continue its wetland activities work with the Florida Department of Environmental Protection and the United States Army Corps of Engineers. The witnesses also testified that the utility will manage, supervise, and support long lead material vendor work, continue AP1000 design support and work, and engage in shared construction program work such as module design and construction initiatives with Westinghouse and Shaw-Stone & Webster. Therefore, we find that PEF continues to demonstrate its intent to build the Levy power plant.

(Order No. PSC-11-0095-FOF-EI, p. 11)

In prehearing position statements, the intervenors' main focus concerning this issue revolves around the question of whether PEF's LNP activities demonstrate the requisite intent to construct the LNP project as contemplated by Order No. PSC-11-0095-FOF-EI.

PEF witness Elnitsky identified and described work on the LNP performed during 2010 and 2011. Witness Elnitsky further identified work which PEF plans to begin or complete during 2012. In general, witness Elnitsky stated:

> All of this work on the LNP is reasonable and necessary in 2011 and 2012 to move the LNP forward on a schedule with the expected in-service dates for Levy Units 1 and 2 in 2021 and 2022 respectively. PEF is moving forward with this

> work on the LNP in 2011 and 2012 with the intent of meeting the current estimated in-service dates for Levy Units 1 and 2. All of this work in 2011 and 2012 is reasonable and necessary to meet that schedule.

OPC witness Jacobs, in his prefiled testimony, presented certain factors and observations he identified as support for OPC's position on this issue. In general, witness Jacobs stated that in his opinion actions to date by PEF "demonstrate that PEF's internal resolve to complete the LNP appears to be weakening." In its post-hearing brief, OPC argues that this weakening of internal resolve shows that PEF has not satisfied its burden of demonstrating reasonable intent.

SACE, in its post-hearing brief stated: "PEF's activities and testimony make it clear that while PEF may intend to create the option to build the LNP it has failed to demonstrate that it intends to actually build the LNP." SACE argues:

> This "option creation" approach on the part of both PEF and FPL fails to demonstrate the requisite intent to actually construct the new nuclear projects, and, as a result, the utilities are not in compliance with Section 366.93, F.S. and thus are not eligible for any further advance cost recovery under this statutory provision.

The remaining intervenors, FIPUG and PCS Phosphate, adopted OPC's position on this issue.

In support of PEF's demonstration of intent to build, witness Elnitsky provided the following overview of LNP work performed, being performed in 2011, or which PEF plans to perform in 2012:

> The Company is also proceeding with work in 2011 and 2012 necessary to meet the current anticipated in-service dates for Levy Units 1 and 2 in 2021 and 2022, which is based on receiving the COL by the second quarter of 2012. This work generally falls within the following broad task descriptions for the LNP: (1) the performance of work activities needed to support environmental permitting and implementation of conditions of certification (CoC); (2) the continued disposition of long lead equipment (LLE) purchase orders; (3) the commencement of work on an updated transmission study given the current, anticipated in-service dates for Levy Units 1 and 2, the commencement of an updated Transmission Study, and any associated targeted land acquisitions; (4) the preparations for, and the negotiations of, the EPC Agreement Amendments(s) necessary to efficiently end the current partial suspension of the LNP and continue with the LNP work on the current, anticipated LNP schedule; (5) continued participation in industry groups to advance the AP-1000 design and operation; (6) active involvement in industry groups such as the Nuclear Energy Institutes (NEI) New Plant Working Group and Nuclear Plant Oversight Committee in addition to INPO's New Plant Deployment Executive Working Group to engage and support industry peers and constructively influence NRC senior management in the development of

regulatory response to emerging issues; and (7) continued joint owner negotiations.

In support of OPC's assertion that PEF's resolve and commitment to complete the LNP in 2021 and 2022 is weakening, witness Jacobs offered the following summary:

> PEF's resolve and commitment to complete the Levy nuclear project in 2021 for Unit 1 and 2022 for Unit 2 is clearly weakening. Factors supporting my conclusion include planning scenarios conducted by the company and senior management of the company.
>
> Planning Scenarios. One of the most significant indicators is PEF's extensive, methodical, and senior executive level analysis of planning scenarios, which indicate that PEF is seriously studying the possibility of further delaying the LNP and relying primarily on gas generation in the current planning horizon.
>
> Declining feasibility and cost-effectiveness of the LNP project. When the 2011 CPVRR analysis is compared with the 2010 CPVRR analysis, the 2011 CPVRR analysis demonstrates that the project is unfavorable and not cost-effective in more cases.
>
> Increased enterprise risks. The two enterprise risks identified by the Company with unfavorable trends are related to the lack of carbon legislation and lower natural gas prices. Both of these risks are fundamental drivers in the economic feasibility of the LNP.
>
> Lack of joint ownership. Joint ownership does not appear to be any more likely in 2011 than in prior years. Circumstances including increased estimated project costs, schedule delays, and recent statements by PEF that no final decision has been made to build LNP indicate no foreseeable receipt of joint owners any time soon, if ever.
>
> Diminished public support. Public support for the LNP and new nuclear power construction in general appears to be declining due to several recent events, including the Fukushima event in Japan, publicity related to the CR3, Crystal River 3 outage, NRC questions on the AP1000 design, and recent flooding at Fort Calhoun Nuclear Plant that got a lot of publicity.

In his rebuttal testimony, PEF witness Elnitsky addressed the concerns raised by OPC witness Jacobs:

> PEF's current IPP for the LNP reflects the Company's commitment to the LNP consistent with the Company's decision in March 2010 to proceed with the LNP on a slower pace by executing an amendment to the EPC agreement to continue the partial suspension and focusing near-term work on obtaining the Combined Operating License for the LNP. This decision is reflected in the April 2010 IPP

> approved by SMC ... and confirmed its commitment to the implementation of this decision for the LNP when it [SMC] approved the current LNP IPP in March 2011.

Witness Elnitsky further stated:

> Jacobs cannot and does not dispute this testimony and evidence of PEF's commitment to the LNP and its present intent to build the LNP on the current schedule with in-service dates for Levy Units 1 and 2 in 2021 and 2022. As a result, there is no reasonable basis for Jacobs' "significant doubt," "concerns," and opinion that PEF's "internal resolve to complete the LNP appears to be weakening" – or however else he characterizes it in his testimony – because the Company has committed to proceed with building Levy Units 1 and 2 with the approval of the current IPP for the LNP consistent with the April 2010 decision that the Commission ruled was reasonable. The Company is incurring cost in 2011 and 2012 to implement that decision.

We find witness Elnitsky's factual statements are consistent with witness Jacobs understanding of PEF's activities concerning the LNP. When questioned by PEF, witness Jacobs stated:

> Q. You would agree that as of March 29, 2011, in the LNP integrated project plan, Progress Energy Florida's senior management approved continued spend and in-service dates of 2021 and 2022 for the LNP project; correct?
> A. That's correct.
> Q. You would agree this year PEF is implementing the decision it presented and the Commission approved in the 2010 NCRC docket; correct?
> A. Yes.
> Q. You would agree with me that PEF's plan for the LNP has not changed since that presented in the 2010 NCRC docket; correct?
> A. I believe there were some minor changes in the 2011 IPP compared to the 2010 IPP, but the overall plan has not changed.
> Q. The plan has not material change – Materially changed in your opinion?
> A. That's correct. Particularly in terms of in-service date.

In its post-hearing brief OPC offered the following argument:

> While PEF publicly maintains that the "plan of record" (which reflects the IPP) or POR has not changed for the Levy Project, Progress Energy has been sending a mixed message about Levy commercial operations dates. Despite PEF's protestations to the contrary, evidence adduced at the hearing contradicts PEF's assertions. Progress Energy's actions (both publicly and as reflected in the confidential record in this case) have undermined confidence in PEF <u>public</u> POR for the Levy Project. These mixed messages include the following: Statements in the media by Progress Energy that it has not made a final decision to build the Levy Project; The serious strategic scenario planning exercises undertaken by

> Progress Energy's Senior Management Committee [SMC] on the eve of the 2010 NCRC proceeding; Material changes to Progress Energy's Security Exchange Commission two most recent 10-Qs, deleting all reference to a Levy Project commercial operation date; and qualified statements to the NRC and Commission about the project's commercial operation date.

PEF provided the following argument concerning its intent:

> Intervenors did speculate about different LNP in-service dates based on Progress Energy Inc.'s Securities Exchange Commission (SEC) filings that included the current established Levy units' in-service dates and, later, did not; and strategic planning scenario analysis PowerPoint presentations that included later in-service dates for the LNP in scenarios that do not reflect the expected plan for the LNP represented by the LNP plan of record in the subsequently executed LNP IPP. This is speculation, not evidence. The evidence demonstrates conclusively the SMC-approved IPP for the in-service dates for Levy Units 1 and 2 in 2021 and 2022.

In reviewing this issue we took guidance from Order No. PSC-11-0095-FOF-EI. We note on page 9 of the Order that a utility need not engage in the siting, design, licensing, and construction of nuclear power plant activities simultaneously in order to meet the statutory requirements under Section 366.93, F.S. Further, as noted on page 11, the utility must demonstrate, through its actions, an intent to build the nuclear power plant for which it seeks advance recovery of costs to be in compliance with Section 366.93, F.S.

We find that PEF has satisfied Section 366.93, F.S., since the LNP activities undertaken in 2011 and projected for 2012 clearly fall within the statutory definition of preconstruction or construction. In addition, PEF's project plan as identified in the March 2011 IPP has not materially changed from last year's plan that was presented to and approved by us in Docket No. 100009-EI. We note that the argument offered by the Intervenors in support of their position on meeting the statutory requirements is substantially the same as that offered by them in Docket No. 100009-EI. Since this argument was rejected by us in Docket No. 100009-EI, and given that the PEF's project plan has not materially changed, we find that the Intervenor's argument shall be rejected in this docket as well.

Addressing demonstration of intent, we find that the factors and observations identified in OPC witness Jacobs testimony, taken in part or as a whole, would not led one to a conclusion concerning intent. We note that when witness Jacobs was cross examined as to what PEF should be doing that it is not currently doing to exhibit an intent to build the LNP, witness Jacobs responded that PEF should have submitted sworn testimony that it is planning to build the units in 2021 and 2022. We find that PEF witness Elnitsky repeated offer just that statement in his prefiled and live testimony at hearing. Likewise, we find that the arguments offered in OPC's brief concerning "mixed messages" are, at best, speculative in character and therefore add little support to conclude that PEF's intent to build is in question.

We find that PEF's actions continues to demonstrate its intent to build the LNP. The project has been approved by PEF's Senior Management Committee and Board of Directors as required by PEF's policy and governing procedures. The LNP is an active project under existing NRC licensing application and construction contract. The project is controlled according to the project parameters contained in the March 2011 IPP. One of the parameters in this IPP is an in-service date for Unit 1 of 2021 and 2022 for Unit 2. These in-service dates are supported by a project schedule. The project activities identified by PEF that are planned, undertaken, or completed during 2011 and 2012 are consistent with this project schedule.

Given the guidance afforded by us in Order No. PSC-11-0095-FOF-EI, and the preponderance of the evidence in the record, we find that PEF has satisfied the requirement to demonstrate its intent to build the nuclear power plant for which it seeks recovery of costs. Therefore we find that find PEF's activities to date continue to demonstrate PEF's intent to build the LNP as contemplated by Section 366.93, F.S.

XXII. Prudence of 2010 LNP Project Management

This issue addresses project management, contracting, accounting and oversight controls employed by PEF during 2010 for the LNP. With the exception of FIPUG, no specific concerns or deficiencies were identified by the intervenors or audit staff witnesses.

A. LNP Project Management and Related Controls

PEF witnesses Garrett, Franke, Hardison and Elnitsky provided reviews of PEF's major project management systems and identified key activities and changes that took place in these systems during 2010. As stated in witness Hardison's prefiled testimony, there have been no substantial changes to the LNP project management and cost oversight controls since she described them in Docket No. 100009-EI. Witness Hardison further testified that in both 2009 and 2010, PEF hired independent expert Gary Doughty of Janus Management Associates, Inc. to review the reasonableness and prudence of the project management and control systems that were in place to manage the LNP. She testified that Mr. Doughty was not retained this year to review the LNP project management and oversight controls since there has been no substantial change to these systems since his review in 2010.

This was confirmed by PEF witness Franke who noted that, for the LNP, these management standards, policies and procedures have been approved as reasonable and prudent by us for three consecutive years.

Since the LNP is a major project, PEF witnesses Garrett and Franke both stated that the project must comply with PEF's major capital projects IPP procedures. According to witness Garrett, per PEF's policy, all projects equal to or exceeding $50 million require completion of an IPP which must be approved by a Project Review Group, the Senior Management Committee, and the Board of Directors.

Witness Hardison noted that PEF senior management revised the LNP IPP in 2010 to incorporate PEF's decision to proceed with the LNP on a slower pace by extending the partial suspension of the EPC agreement and focusing on near term work to obtain the COL for the LNP.

Witness Elnitsky confirmed this change in the IPP and described actions that PEF took to implement the Company's decision to continue to pursue the COL. Witness Elnitsky stated that this project approach was found to be reasonable by us in Order No. PSC-11-0095-FOF-EI. Actions identified by witness Elnitsky included: continued work with the NRC on obtaining the LNP COL, work on obtaining or fulfilling other regulatory permit requirements, work on the disposition of Long Lead Equipment (LLE) purchase orders, and preparations for an updated transmission study.

B. LNP Accounting and Related Controls

PEF's LNP accounting and related controls were described by witnesses Garrett, Hardison and Elnitsky. Witness Garrett noted in his prefiled testimony that project accounting and cost oversight controls utilized by PEF to ensure the proper accounting treatment for the LNP and CR3 Uprate projects have not substantively changed from those found last year by us as prudent. However, according to witness Hardison:

> PEF continues to review policies, procedures, and controls on an ongoing basis and makes revisions and enhancements based on changing business conditions, organizational changes and lessons learned. This process of continuous review of our policies, procedures, and controls is a best practice in our industry and is part of our existing LNP project management and cost control oversight.

PEF witness Hardison identified that during 2010 PEF revised or enhanced 69 corporate, nuclear and EPC procedures. In addition, eight new procedures were created. Of these eight new procedures, five were new "Project Management Center of Excellence" procedures which generally address the management of contractors for the LNP. Witness Hardison also noted that, during 2010, a vendor invoice audit was completed by Shaw and the Joint Venture Team (Sargent & Lundy, Worley Parsons, and CH2M Hill). Activities performed under this audit included a review of vendor time, expense, and subcontract procedures and verification that invoices were being billed according to contract terms and conditions. Contract language was also strengthened in all Joint Venture Team COLA contract work authorizations to better define the change order process.

Witness Garrett stated that PEF verified that their accounting and cost oversight controls are effective based on the standards and framework established by the Committee of Sponsoring Organizations of the Treadway Commission. This framework includes reviews by both internal and external audit teams. During 2010, PEF's internal auditors determined that PEF maintained effective controls over financial reporting and identified no material weakness within the required Sarbanes-Oxley controls. PEF's external auditor, Deloitte and Touche, also determined that during 2010, PEF maintained effective controls regarding financial reporting.

In summary, witness Hardison concluded:

> These project management policies and procedures reflect the collective experience and knowledge of the Company and have been vetted, enhanced, and revised over several years to reflect industry leading best project management and cost oversight policies, practices and procedures. We believe, therefore, that our project management policies and procedures are consistent with the best practices for capital project management in the industry and are reasonable and prudent.

Audit staff witnesses Coston and Carpenter reviewed PEF's project management, accounting, and related controls in their 2011 audit report on CR3 and LNP. In this report, witnesses Coston and Carpenter stated; "The primary objective of this review was to document project key developments, along with the organization, management, internal controls and oversight that PEF has in place or plans to employ for these projects." A review of this report revealed no recommendations or issues concerning project management or project controls.

A review of OPC witness Jacobs' testimony revealed that he did not focus his efforts on the adequacy of PEF's project management and cost control given, in his opinion, the time constraints in the docket. Witness Jacobs, in his testimony and in cross-examination, stated that he had no opinions concerning PEF's efforts in this area during 2010. Witness Hardison noted in her prefiled testimony that witness Jacobs had reviewed the LNP management and cost controls in the 2009 and 2010 NCRC proceedings and had expressed no opinion concerning the prudence of these systems or offered any recommendations concerning PEF's LNP project management and cost oversight controls.

In their-post hearing briefs, OPC, PCS Phosphate, and SACE stated no position on this issue. FIPUG, in its post-hearing brief, stated that: "as a condition precedent to finding that certain 2010 costs were reasonable and prudent; the Levy project must be feasible." We disagree. We find that the application of a forward looking analysis, such as the feasibility analysis, when determining if a past cost was prudently incurred would be an inappropriate application of hindsight review and inconsistent with our practice in this docket.

Based on the foregoing, we find that PEF's 2010 LNP project management, accounting, and related controls were subjected to a reasonable level of review and examination sufficient to determine prudence. We find that the level of review and examination is significant because, "the standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should have been known, at the time the decision was made." (See Order No. PSC-08-0749-FOF-EI, p. 28) We note that we once again affirmed this opinion concerning the prudence standard in Order No. PSC-09-0783-FOF-EI:

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

We further note that a review of the record produced no evidence that any 2010 LNP project management decisions or accounting actions were challenged as to their need or reasonableness nor did any intervenor identified that these decisions or actions produced an unreasonable or imprudent result.

C. Conclusion

Therefore we find that project management, contracting, accounting and cost oversight controls employed by PEF for the LNP during 2010 were reasonable and prudent.

XXIII. Prudence of 2010 LNP Incurred Costs

This issue addresses PEF's request concerning the prudence of 2010 final costs and true-up amounts for the LNP. PEF witness Garrett provided support for the activities and the method used to determine the requested recovery amounts. PEF witnesses Hardison and Elnitsky provided descriptions of the activities and project cost variances associated with the final 2010 costs and true-up amounts for the LNP.

Witness Garrett stated that the data was taken from PEF's books and records that are kept in accordance with general accepted accounting principles and practices, provisions of the Uniform System of Accounts, and other accounting rules and orders as established by this Commission.

Witness Garrett identified the 2010 LNP costs PEF believes were prudently incurred. These costs include: Capital Costs in the amount of $[redacted] ($79,917,103 jurisdictional), O&M expenses of $2,877,079 ($2,496,726 jurisdictional), Carrying Costs of $49,280,391 and a credit to other adjustments in the amount of $5,302. In support of PEF's request, witness Hardison stated in her prefiled testimony:

> These 2010 LNP costs were incurred in connection with licensing application activities to support the Levy Combined Operating License Application (COLA) to the Nuclear Regulatory Commission (NRC), engineering and procurement activities in support of the COLA, and for continuation of PEF's Engineering, Procurement and Construction (EPC) contract and disposition of Long Lead Equipment (LLE) Purchase Orders (PO) for the LNP. In addition, costs were incurred for Levy Transmission strategic land acquisition activities. PEF took adequate steps to ensure that the 2010 LNP costs were reasonable and prudent and that all of these costs were necessary to the LNP for the completion and operation of Levy Units 1 & 2.

PEF witness Elnitsky provided a detailed review of PEF's efforts during 2010 concerning the disposition of the LLE purchase orders.

The final 2010 project costs were compared to our prior approved recovered amounts to determine the net final true-up amount for 2010 as a $60,743,424 over-recovery. Witness Garrett states that PEF is requesting that we approve, as reasonable, this over-recovery amount as PEF's 2010 final true-up and incorporate it in determining the 2012 recovery factor.

The make-up of the final 2010 LNP true-up is the summation of the following factors: a $58,175,233 over-projection of Preconstruction Costs, a $1,190,702 over-projection of O&M expenses, a $1,372,188 over-projection of Carrying Costs, and a $5,302 over-projection of other adjustments.

OPC, PCS Phosphate, and SACE in their post-hearing briefs did not offer a position on this issue. FIPUG stated in its brief that, "This is a fall out amount from the substantive issues."

As previously discussed above, the standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should have been known, at the time the decision was made. Order No. PSC-08-0479-FOF-EI, p. 28

In reviewing the post-hearing position of the parties, we note that no specific items were identified concerning PEF's requested 2010 incurred costs and final true-up amounts for the LNP. We agree with PEF witness Elnitsky's observation that none of the audit staff or intervenor witnesses' testimony filed in this proceeding disputed PEF's testimony and other evidence that the actual costs for the LNP in 2010 were prudently incurred. During cross-examination, OPC witness Jacobs, stated he had no opinion whether 2010 LNP actual costs were prudently incurred. Reviews of audit staff witnesses' accounting and management review audits identified no recommendations concerning 2010 LNP costs.

Consistent with our decision above, our verification of PEF's calculations, true-up amounts, and a preponderance of the evidence in the record, we find that PEF has demonstrated the prudence of its requested 2010 LNP costs and true-up amounts. Therefore we approve the following amounts as prudently incurred 2010 LNP costs: Capital Costs of $[redacted] ($79,917,103 jurisdictional), O&M expenses of $2,877,079 ($2,496,726 jurisdictional), Carrying Costs of $49,280,391, and a credit to other adjustments in the amount of $5,302. The resulting final 2010 true-up of negative $60,743,424 shall be used in determining the 2012 NCRC recovery amount.

XXIV. Recovery of 2011 Non-Combined Operating License Costs

This issue addresses whether it is reasonable for PEF to incur any estimated 2011 LNP costs not necessary for receipt of the COL. PEF witness Elnitsky identified LNP actions and activities PEF continued to work on or started during 2011. Witness Elnitsky further described the importance and necessity of the identified 2011 project activities. In general, concerning the need and reasonableness of these activities and costs, witness Elnitsky stated:

> All of this work on the LNP is reasonable and necessary in 2011 and 2012 to move the LNP forward on a schedule with the expected in-service dates for Levy

> Units 1 and 2 in 2021 and 2022 respectively. PEF is moving forward with this work on the LNP in 2011 and 2012 with the intent of meeting the current estimated in-service dates for Levy Units 1 and 2. All of this work in 2011 and 2012 is reasonable and necessary to meet that schedule.

OPC witness Jacobs provided support for OPC's position that recovery of 2011 LNP costs should be limited to only those activities necessary to obtain receipt of the LNP COL. Witness Jacobs stated:

> While the Commission may have found PEF meets the minimum test set out in the 2010 NCRC order of "demonstrating an intent to build" PEF's actions continue to demonstrate doubt as to the likelihood of completion of the project on the current schedule – if at all. For this reason, customers should not be forced to bear any of the costs beyond that needed to meet PEF's Commission-endorsed goal of spending hundreds of millions of dollars to receive the COL before then deciding where to go next.

FIPUG and SACE's position concerning the recovery of 2011 LNP costs, as reflected in their post-hearing briefs, is that: "PEF failed to demonstrate the requisite intent to actually construct the LNP; therefore, we should not approve recovery of any estimated 2011 costs not necessary for receipt of the COL." We addressed the issue of intent above.

PCS Phosphate, in its post-hearing brief, adopted the position of OPC. In its post-hearing brief OPC recommended that:

> [t]he Commission disallow as unreasonable all the yet-to-be-incurred non-COLA costs PEF estimates to incur in 2011 and projects to incur in 2012. Alternatively, the Commission should find the following as two conditions precedent before allowing receipt of any non-COLA costs on a true-up basis: 1) the receipt of the COL; and 2) PEF's affirmative and irrevocable decision to issue the FNTP [Final Notice to Proceed] and thus proceed with the Levy Project according to the 2021/2022 commercial operations dates.

As presented in OPC witness Jacobs' testimony in Docket No. 100009-EI, we have reviewed and found as reasonable PEF's revised LNP approach to proceed with the LNP on a slower pace by extending the partial suspension of the EPC contract and focus near-term work on obtaining the COL.[24] Due to this change in approach, witness Jacobs opined that we should only allow actual COLA necessary costs to be recovered or defer recovery of all non-COLA costs to a later date or determine that any non incurred non-COLA expenses are unreasonable at this time.

We note that during PEF's cross-examination of witness Jacobs, he responded to the following LNP questions concerning reasonability and necessity of 2011 costs:

[24] Order No. PSC-11-0095-FOF-EI, p. 35.

Q. Is it true that it's necessary - - isn't it true that it's necessary for Progress Energy Florida to perform preconstruction and construction work for the LNP?
A. Yes. That's correct.
Q. Mr. Elnitsky, as project manager, has testified the in-service dates for the Levy nuclear project are 2021 and 2022; isn't that correct?
A. He has testified that those are the dates included in the plan of record. That's correct.
Q. So Mr. Elnitsky has testified that the in-service dates are 2021 and 2022 in front of this Commission?
A. That's correct.
Q. And you have no reason to disagree with Mr. Elnitsky that non-COL related preconstruction and construction work would be necessary to meet those in-service dates; correct?
A. That's correct.
Q. Nowhere in your 2011 testimony do you state that any of the non-COL preconstruction or construction costs estimated for 2011 and 2012 are unreasonable; right?
A. That's correct. Only to the extent that they are, would be performed prior to receiving the COL.
Q. You don't state anywhere that they're unreasonable in amount.
A. No. That's correct.
Q. You don't state anywhere that they're unnecessary for the LNP.
A. That's correct.
Q. You would agree then that your testimony for 2011 includes no opinion that any specific 2011 or projected 2012 LNP cost is unreasonable.
A. In amount, that's correct. But not in timing of those, of those expenses.

Under additional questioning concerning the timing of non-COL activities and expenses witness Jacobs offered the following clarifying comments:

Q. Now I assume that your statement that only pursuing activities that are necessary to obtain the COL are what Progress should be doing. And in doing so, it would not affect the in-service date of 2021 and 2022; correct?
A. That's correct.
Q. So I would assume that those activities that are not part of the COL, the transmission work, land purchases, et cetera, are not on the critical path for the project schedule?
A. That's correct.
Q. And I looked through this, the integrated project plan. Is that the only document you reviewed? Is there a more detailed schedule that clearly shows what critical path items are?
A. I'm sure there is. I have not reviewed - - I only relied on reviewing the IPP. But, but I, I'm familiar with the schedule required to build an AP1000 due to my work for the Vogtle project. I know that schedule in detail, and I know the durations of activities that are required. And there's enough float in the Levy

County schedule to complete any work that's needed, any work that would be delayed.

Q. And just based on the information in the integrated project plan and your experience for the Georgia plant? I'm just trying to understand. Because that's a very powerful statement that you made in determining what is on a critical path and what is not, and I want to understand what you're basing that on. So if you can elaborate on that again.

A. Sure. Well specifically we've said the transmission studies, I don't know if that's what you're referring to, but there are several years of time to complete the transmission studies and any transmission work that needs to be done, and that work could be accelerated. I don't believe that work has to be done prior to receiving the COL. And, again, since the company hasn't even decided to build the project, it seems to spend additional money before making that decision is not reasonable.

During cross-examination, PEF witness Elnitsky voiced disagreement with witness Jacobs's assessment concerning the timing of non-COL activities and expenses. Witness Elnitsky testified:

Q. Would you agree with Mr. Jacobs when I asked him the question are any of those items (non-COL) on the critical path and that they would delay the in-service date of the projects, and he indicated that none of those items are critical path items; do you agree with that?

A. No, I do not. And the reason is we have a pretty detailed project schedule that we've provided in production of documents that clearly lays out critical path activities necessary to maintain the current 2021 service date.

Later, witness Elnitsky was asked by FIPUG:

Q. Mr. Elnitsky, all of this kind of happened pretty quickly with this document (detailed project schedule). I appreciate you answering the questions. I was interested in matching the items that you had on your handwritten piece of paper to this, and I was hoping I could argue that all the items that are on this handwritten list that don't fall on critical path are not things we need to be spending money on. Would you kind of agree with that?

A. No, I would not. And, again, because if you stop doing some of those activities, those activities then become the critical path because it disrupts the schedule.

Our review of the record found no direct challenge to the level of what PEF presented as its actual or estimated 2011 costs for the LNP. Nor did we find that any of the activities which produced these costs were challenged by the intervenors on the grounds of their not being necessary for the project. The information reflected in the exchange between OPC witness Jacobs and PEF counsel supports this conclusion by us. Based on record evidence, we find that

PEF has met its requirement to demonstrate that these costs are reasonable in level and necessary for the LNP.

Given our findings above concerning intent, and the discussions above, the remaining question to be addressed in this issue is the reasonableness of the timing of non-COL related expenses. Witness Jacobs opined that certain non-COL related activities can be re-scheduled to begin after the receipt of the COL. By implementing this change in schedule, total project spending would be reduced in the event that PEF cancels the LNP shortly after COL receipt. Witness Jacobs opined that based on his review of the current LNP IPP and his knowledge of the construction needs for Plant Vogtle [a plant using the same AP1000 technology], the LNP has sufficient "float" in the project schedule to accommodate his recommended delay in starting certain project activities.

We agree with PEF witness Elnitsky that the detailed project schedule showing critical paths, as compared to the IPP, is a superior document concerning when an activity must be scheduled to begin or end so as to not affect the overall project's COD or "float." Further, while we do not dispute OPC witness Jacobs' understanding of the construction needs for the Vogtle plant, we note that beyond building the same type of unit, there is no record evidence which indicates a similarity of any other non-AP1000 project requirements (such as transmission) between the two projects. Given this, we do not find that there is a basis to evaluate whether there is sufficient "float" in the LNP schedule to accommodate witness Jacobs' recommended change in scheduling activities based on his expert knowledge. We note that our review of revealed that the preparation for and initialization of a transmission study is identified as a critical path item during the period under review. We find that the information contained on the detail project schedule supports PEF's contention that the timing of the non-COL activities is reasonable. As clearly displayed in this schedule, work on these non-COL activities needs to begin in 2011 and 2012 to remain on or within the critical path.

Consistent with our findings above, and the preponderance of evidence in the record, we find that PEF has been reasonable in incurring LNP costs in 2011 including non-COL related costs which are reasonably necessary to meet the scheduled 2021 COD date for Levy Unit 1. Therefore, we find that it is reasonable for PEF to incur estimated 2011 LNP costs which are not directly necessary for receipt of the combined operating license for the Levy project.

XXV. Reasonableness of 2011 LNP Estimated Costs

This issue addresses PEF's request concerning the reasonableness of 2011 actual/estimated and estimated true-up amounts for the LNP. PEF witness Foster provided support for the costs and method of calculations used to determine the requested recovery amount. PEF witnesses Hardison and Elnitsky provided an overview of activities, project costs and variances associated with the actual/estimated 2011 costs and true-up amounts for the LNP.

Witness Foster stated that the schedules provided with his testimony were true and accurate and filed in accordance with the requirements of the NCRC and other rules and orders established by us.

Witness Foster identified 2011 LNP actual/estimated costs that PEF believes were reasonably incurred. These costs include: Capital Costs in the amount of $[redacted] ($72,747,008 jurisdictional), O&M expenses of $1,557,765 ($1,414,573 jurisdictional), and Carrying Costs in the amount of $48,372,525. In support of PEF's request, witness Hardison provided descriptions of the activities associated with these amounts:

> In 2011 and 2012, PEF has incurred and will continue to incur reasonable costs for work on its Combined Operating License Application (COLA) to the Nuclear Regulatory Commission (NRC) and work related to environmental permitting and implementation of the conditions of certifications for its Site Certification Application (SCA), which was approved by the Governor and Cabinet sitting as the Siting Board. This work is necessary to obtain the required licenses and permits for the LNP.
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> In addition, under its Engineering, Procurement, and Construction Agreement (EPC Agreement) entered into with Westinghouse and Shaw, Stone and Webster (the Consortium), PEF incurred and will continue to incur costs for Long Lead Equipment (LLE) items, associated support costs, and purchase order management and disposition. PEF will also prepare for and commence negotiations of necessary amendments to the EPC Agreement to efficiently end the current partial suspension of the LNP and continue with the LNP work on the anticipated LNP schedule as discussed in the testimony of Mr. John Elnitsky filed in this docket.
>
> In 2011, PEF will begin work on an updated transmission study given the anticipated in-service dates for the LNP. In 2012, PEF will commence work related to detailed transmission design packages. In 2011 and 2012, PEF will continue activity associated with strategic land acquisitions for transmission lines.
>
> As demonstrated in my testimony and the NFR's 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 2011 and all of 2012. The cost of this work is necessary for the LNP and therefore is reasonable.

PEF witness Elnitsky provided a detailed review of PEF's efforts on and the status of the LNP during 2011 in his prefiled testimony.

As testified by PEF witness Foster, a comparison of actual 2011 LNP costs to previously approved projected 2011 LNP costs results in a 2011 true-up amount of a $5,775,217 under-recovery. PEF is requesting that this true-up amount be used in determining the 2012 NCRC recovery amount. The requested 2011 estimated true-up amount includes the following items: $6,190,954 under-projection of Preconstruction Costs, a $2,409,310 over-projection of O&M expenses, and a $1,993,574 under-projection of Carrying Costs.

SACE's position concerning the recovery of 2011 LNP costs is, "PEF has failed to demonstrate the requisite intent to actually construct the LNP, therefore, the Commission should not approve recovery of any estimated 2011 costs not necessary for receipt of the COL." As stated, we addressed the issue of intent above.

PCS Phosphate, in its post-hearing brief, adopted the position of OPC. FIPUG stated that this is a fall out amount from the substantive issues.

In its post-hearing brief OPC stated:

> OPC contests the estimated non-COLA costs and requests that the Commission finds and disallow the estimated non-COLA costs as unreasonable until after the receipt of the COL and PEF's affirmative and irrevocable decision to issue the FNTP and thus proceed with the Levy Project in order to meet the 2021/2022 commercial operations dates. Alternatively, defer a finding of reasonableness until then.

As we note above, none of the intervenors directly challenged the level of actual and estimated LNP 2011 costs or challenged the necessity of the activities which produced these costs. In an attempt to identify the non-COL activities and associated amounts, OPC provided the following information in its post-hearing brief:

> OPC urges this Commission to find as unreasonable, and thus disallow for 2012 recovery all not-yet-incurred non-COLA costs. The non-COLA costs OPC has identified for 2011 and 2012 are as follows: $400,000 in transmission study costs (T. 1859); $xx (confidential amount) in transmission engineering procurement construction request for proposal (EPC RFP) and detailed design costs (T. 1860-1861; Confidential transmission EPC RFP amount shown in Ex. 210); $3 million additional land acquisition costs (T. 1862); and $200,000 in costs to restart internal pre-FNTP negotiations and long-lead equipment (LLE) negotiations. (T. 1863)

We were unable to verify the accuracy of the cost amounts identified in OPC's brief for the non-COL activities in dispute. Our review of the transcript references offered by OPC and PEF witness Foster's Exhibit 149, leads us to conclude that the referenced dollar amounts, represent a mixed bag of activities, all of which affect the calculations of a recovery amount in any one year in different ways. Consistent with our findings above, our verification of PEF's calculations and true-up amount, and the preponderance of evidence in the record, we find that PEF has demonstrated the reasonableness of its requested 2011 actual/estimated costs and true-up amounts for the LNP. Therefore, we approve as reasonable the following LNP actual/estimated 2011 costs: Capital Costs of $[redacted] ($72,747,008 jurisdictional), O&M Costs of $1,557,765 ($1,414,573 jurisdictional), and Carrying Costs of $48,372,525. We also approve as reasonable an estimated true-up of 2011 LNP costs of a $5,775,217 under-recovery for use in determining the 2012 NCRC recovery amount.

XXVI. Reasonableness of PEF to Incur Any Projected 2012 Costs Not Necessary for Receipt of the Combined Operating License (COL)

This issue addresses whether it is reasonable for PEF to incur certain projected 2012 LNP costs which are not necessary for receipt of the COL. PEF witness Elnitsky identified LNP activities PEF has scheduled to begin or complete in 2012. Witness Elnitsky described these 2012 project activities and why they are important and necessary to the project. In general, concerning the need and reasonableness of these 2012 projected costs, witness Elnitsky stated:

> All of this work on the LNP is reasonable and necessary in 2011 and 2012 to move the LNP forward on a schedule with the expected in-service dates for Levy Units 1 and 2 in 2021 and 2022 respectively. PEF is moving forward with this work on the LNP in 2011 and 2012 with the intent of meeting the current estimated in-service dates for Levy Units 1 and 2. All of this work in 2011 and 2012 is reasonable and necessary to meet that schedule.

OPC witness Jacobs asserted that recovery of 2012 LNP costs should be limited to only those activities necessary to obtain receipt of the LNP COL. Witness Jacobs argued:

> While the Commission may have found PEF meets the minimum test set out in the 2010 NCRC order of "demonstrating an intent to build" PEF's actions continue to demonstrate doubt as to the likelihood of completion of the project on the current schedule – if at all. For this reason, customers should not be forced to bear any of the costs beyond that needed to meet PEF's Commission-endorsed goal of spending hundreds of millions of dollars to receive the COL before then deciding where to go next.

FIPUG and SACE's position concerning the recovery of certain projected 2012 LNP costs, as reflected in their post-hearing briefs is: "PEF has failed to demonstrate the requisite intent to actually construct the LNP; therefore, the Commission should not approve recovery of any projected 2012 costs not necessary for receipt of the COL." The issue of intent to build was addressed above.

PCS Phosphate, in its post-hearing brief, adopted the position of OPC. In its post-hearing brief, OPC stated its position that the Commission should:

> disallow as unreasonable all the yet-to-be-incurred non-COLA costs PEF estimates to incur in 2011 and projects to incur in 2012. Alternatively, the Commission should find the following as two conditions precedent before allowing receipt of any non-COLA costs on a true-up basis: 1) the receipt of the COL; and 2) PEF's affirmative and irrevocable decision to issue the FNTP and thus proceed with the Levy Project according to the 2021/2022 commercial operations dates.

We note that the concerns and arguments of the intervenors in this issue are exactly the same as those presented above for the 2011 period. In addition, since projected 2012 costs are, by definition, forward-looking, the reasonableness of incurring such projected costs will be affected by our decision concerning continuing project feasibility. Project feasibility for the LNP was addressed earlier in this Order.

Consistent with our findings above and the preponderance of evidence in the record, we find that it is reasonable for PEF to incur projected 2012 LNP costs necessary to obtain the LNP COL and other non-COL related costs which are reasonably necessary to meet the scheduled 2021 COD date for Levy Unit 1. Therefore, we find that it is reasonable for PEF to incur projected 2012 LNP costs which are not directly necessary for receipt of the combined operating license for the Levy project.

XXVII. 2012 System and Jurisdictional Amounts Approved as Reasonably Projected Costs for PEF's Levy Units 1 & 2 Project

This issue addresses PEF's request concerning the reasonableness of projected 2012 LNP costs. PEF witness Foster provided support for the costs and method of valuations used to determine the requested recovery amount. PEF witnesses Hardison and Elnitsky provided an overview of activities and project costs associated with the requested projected 2012 LNP recovery amount.

Witness Foster stated that the schedules attached to his testimony are true and accurate and filed in accordance with the requirements of the NCRC and other rules and orders established by us.

Witness Foster identified the projected 2012 LNP costs that PEF believes are reasonably forecasted. These costs include: Capital Costs of $[redacted] ($39,583,863 jurisdictional), O&M expenses of $1,545,388 ($1,405,073 jurisdictional) and Carrying Costs of $48,466,132.

PEF requested that we approve, as reasonable, the recovery of projected 2012 LNP costs in the amount of $75,324,920. This amount includes $25,453,715 Preconstruction and Site Selection costs, $1,405,073 O&M expenses, and Carrying Costs of $48,466,131. In support of PEF's request, witness Hardison provided descriptions of the activities associated with these amounts:

> In 2011 and 2012, PEF has incurred and will continue to incur reasonable costs for work on its Combined Operating License Application (COLA) to the Nuclear Regulatory Commission (NRC) and work related to environmental permitting and implementation of the conditions of certifications for its Site Certification Application (SCA), which was approved by the Governor and Cabinet sitting as the Siting Board. This work is necessary to obtain the required licenses and permits for the LNP.
>
> In addition, under its Engineering, Procurement, and Construction Agreement (EPC Agreement) entered into with Westinghouse and Shaw, Stone and Webster

(the Consortium), PEF incurred and will continue to incur costs for Long Lead Equipment (LLE) items, associated support costs, and purchase order management and disposition. PEF will also prepare for and commence negotiations of necessary amendments to the EPC Agreement to efficiently end the current partial suspension of the LNP and continue with the LNP work on the anticipated LNP schedule as discussed in the testimony of Mr. John Elnitsky filed in this docket.

In 2011, PEF will begin work on an updated transmission study given the anticipated in-service dates for the LNP. In 2012, PEF will commence work related to detailed transmission design packages. In 2011 and 2012, PEF will continue activity associated with strategic land acquisitions for transmission lines.

As demonstrated in my testimony and the NFR's 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 2011 and all of 2012. The cost of this work is necessary for the LNP and therefore reasonable.

PEF witness Elnitsky provided a review of PEF's efforts that will be completed or begun during 2012 on the LNP.

Responding to questions during cross-examination concerning the reasonableness and necessity of LNP estimate or projected 2011/2012 cost, OPC witness Jacobs testified:

Q. So you have no opinion that any specific 2011 or 2012 LNP costs are unreasonable or imprudent in amount?
A. In amount. That's correct.
Q. Nowhere in your 2011 testimony do you state that any of the non-COL preconstruction or construction costs estimated for 2011 and 2012 are unreasonable; right?
A. That's correct. Only to the extent that they are, would be performed prior to receiving the COL.
Q. You don't state anywhere that they're unnecessary for the LNP?
A. No. That's correct.
Q. You would agree then that your testimony for 2011 includes no opinion that any specific 2011 or projected 2012 LNP cost is unreasonable?
A. In amount, that's correct. But not in timing of those, of those expenses.

SACE's position concerning the recovery of 2012 LNP costs is that, "PEF has failed to demonstrate the requisite intent to actually construct the LNP, therefore, the Commission should not approve recovery of any projected 2012 costs not necessary for receipt of the COL." We addressed the issue of intent earlier in this Order.

PCS Phosphate, in its brief, adopted the position of OPC. OPC's brief on this issue notes:

> OPC contests the estimated non-COLA costs and requests that the Commission finds and disallow the projected non-COLA costs as unreasonable until after the receipt of the COL and PEF's affirmative and irrevocable decision to issue the FNTP and thus proceed with the Levy Project in order to meet the 2021/2022 commercial operations dates. Alternatively, defer a finding of reasonableness until then.

FIPUG, in its post-hearing brief, noted that this is a fall out amount from the substantive issues.

We note that beyond the parties' concerns over project feasibility and the limits on the recovery of certain costs, no party identified any other specific concerns as to the reasonableness of projected 2012 LNP activities or associated projected costs. Consistent with our findings above, our verification of PEF's forecasts and calculations, and the preponderance of evidence in the record, we find that PEF has demonstrated the reasonableness of its requested projected 2012 costs for the LNP. Therefore, we approve the following LNP projected 2012 costs as reasonable: Capital Costs of $[redacted] ($39,583,863 jurisdictional), O&M expenses of $1,545,388 ($1,405,073 jurisdictional) and Carrying Costs of $48,466,132. Further, we approve $75,324,920 as reasonable projected LNP costs for use in determining the 2012 NCRC recovery amount.

<u>XXVIII. 2012 Rate Management Amount</u>

This issue addresses what dollar amount from the rate management plan (RMP) deferred balance should be included in the 2012 CCRC factor.

PEF witness Foster identified the mechanics of PEF's calculation, and provided support for PEF's 2011 requested amount to be withdrawn from the RMP deferred balance for recovery in the 2012 CCRC factor. In his testimony, witness Foster stated that PEF is requesting recovery of approximately $115 million from the deferred balance plus $15.1 million in associated carrying costs. The amount would be recognized in the 2012 NCRC amount for recovery in the CCRC factor. Both PEF witnesses Foster and Elnitsky submitted rebuttal testimony responding to the testimony of OPC witness Jacobs on this issue.

OPC witness Jacobs testified that OPC objected to PEF's request to accelerate recovery of the RMP remaining deferred balance. Witness Jacobs provided support for his opinion and OPC's position on this issue.

<u>A. Brief history of the RMP</u>

In Docket No. 090009-EI, PEF proposed that we approve a rate management plan to provide some level of relief to ratepayers in 2010. Under this plan, PEF would defer recovery of certain approved and prudently incurred costs and subsequently recover them over a five-year period by applying a fixed recovery amount (approximately $60 million) in each of the following year's recovery factors. The proposed deferred amount was approximately $273 million, which consisted of certain site selection and preconstruction costs.

In Order No. PSC-09-0783-FOF-EI, we approved a modified version of PEF's proposal. The modification approved by us eliminated the fixed recovery schedule. As outlined on page 38 of the Order, this modification introduced a level of recovery flexibility, allowing for more effective management of rates over time:

> We agree that PEF's proposed rate management plan could provide relief to ratepayers by decreasing rate impact during 2010 and that PEF shall be permitted to defer recovery of costs that have been approved for recovery through the NCRC. However, while PEF's proposal suggests recovery of the deferred balance over a five-year period, we find that greater flexibility to manage rates shall be retained and that PEF shall be permitted to annually reconsider changes to the deferred amount and recovery schedule.
>
> Therefore, we approve a rate management plan whereby PEF will be permitted to defer recovery of certain approved site selection and preconstruction costs and then collect those cost during subsequent years. The deferred costs shall be treated as a regulatory asset with carrying charges applied pursuant to Section 366.93(1)(f), F.S., and Rule 25-6.0423(5)(a), F,A.C.

In Order No. PSC-11-0095-FOF-EI, p. 46, we reaffirmed our position concerning the mechanics of the RMP:

> We note our approval of the rate management plan in Order No PSC-09-0783-FOF-EI did not set or require a particular amortization schedule be used for any recovery of the deferred balance.

In effect, we through these Orders required PEF to annually file updated RMP testimony and schedules to establish the amount, if any, to be removed from the deferred balance and recognized for recovery in an NCRC recovery amount.

B. Current Request

PEF requested that approximately $115 million from the deferred balance and an additional $15.1 million in associated carrying costs be included for recovery in the 2012 CCRC factor. We note that the actual dollar amount requested to be withdrawn from the deferred balance is $114,968,361. In support of this request witness Foster testified:

> Consistent with this Order (PSC-09-0783-FOF-EI) PEF has looked at both the short term and long term implications of the amortization schedule. In the short term, there is an opportunity to reduce the outstanding balance of already approved for recovery costs while still decreasing the overall NCRC rate from 2011 to 2012. This has the benefit of reducing the carrying costs to our customers over the next several years. Looking out into future years, it is apparent that once PEF receives the COL and gives Westinghouse a full notice to proceed, the estimated revenue requirements per year increase significantly.

OPC is opposed to what it characterized as an accelerated recovery of the remaining deferred balance. OPC witness Jacobs argued:

> This accelerated recovery in one year would adversely affect PEF's customers. In these trying economic times for PEF's customers, PEF should not be allowed to accelerate the recovery of this deferred amount. In addition, PEF's intent to accelerate recovery of the remaining deferred balance in 2012 may indicate that Progress Energy may consider cancelling the LNP project once all the outstanding monies approved for recovery for the LNP have been recovered from the customer.

We assume that OPC's characterization of the acceleration of recovery is based on an understanding that we approved PEF to recover annually at least $60 million from the RMP deferred balance. OPC witness Jacobs further testified:

> Given the current economic situation, the cost imposed on PEF customers for Crystal River 3 replacement steam generators, replacement power costs due to the extended outage at Crystal River 3 and costs for the LNP which currently contribute nearly $5 per month to the residential bill, I do not believe it is reasonable for customer bills to be any higher than absolutely necessary.

In response to witness Jacobs's statements, PEF witness Elnitsky provided the following rebuttal testimony:

> I wanted to address Jacobs' rank and incorrect speculation that the Company's proposal is an indication that the Company is not committed to the LNP. First, the exact opposite is true; the Company's proposal is an indication of the Company's commitment to build the Levy Units on the current planned schedule with an in service dates for Levy Units 1 and 2 in 2021 and 2022. PEF proposes its current rate management plan to reduce the customer rate impact due to the LNP in 2013 and 2014 when the Company plans to increase spending on the LNP under the current plan to meet the 2021 and 2022 schedule in-service dates for Levy Units 1 and 2.
>
> Second, PEF is entitled to recover the costs under the LNP rate management plan no matter what decision the Commission makes with respect to the Company's proposal. These prudent costs do not represent "dollars remaining to be recovered" in the sense that Jacobs apparently uses these words because they are not subject to disallowance no matter what decision the Company makes in the future with respect to the LNP. These costs were determined prudent by the Commission and, therefore PEF is entitled to recover them from customers, whether or not PEF in the future cancels the LNP or completes the LNP.

In their post-hearing briefs, FIPUG and SACE stated that they adopted OPC's position. In reviewing the evidence, we find that the testimony and arguments presented regarding whether the requested recovery amount is an accelerated recovery, or that it provides any insight as to PEF's intent to build the LNP, provides little help to us in making a decision on this issue. As identified in the above-noted Orders, we did not approve or set any amount that would be periodically recovered in future periods from the RMP deferred balance. Similarly, since we have previously found that the costs which make up the deferred balance were prudently incurred, PEF has the right to recover the entire balance whether it continues to build the LNP or not. We note that OPC witness Jacobs, during cross-examination, acknowledged this is the case:

> Q. Are you aware that this money was already determined prudent in prior NCRC proceedings and is already approved for recovery, notwithstanding what happens with the LNP going forward?
> A. That's correct. I'm not disagreeing with the recovery of this amount, merely with the timing and the acceleration of these costs.

We find that the standard we shall apply in making a decision on this issue is not the standard of prudence as applied to many of the other issues in this docket. Since the costs which comprise the RMP deferred balance have previously been determined to be prudently incurred, we are not required to make this decision again. We find that the proper measure we shall apply in this issue is whether or not the requested level of recovery from the RMP deferred balance reasonably meets the objective of annually managing customer rate impacts.

We note that selecting an amount to be withdrawn from the deferred balance in any year is, for lack of a better term, a balancing act. The smaller an amount recovered in any one year will result in comparatively lower rates in that year but, due to carrying costs and possible compounding of unrecovered carrying costs, place comparatively more stress on rates in future years. The reverse (a higher current recovery) also holds true in this inverse relationship between current and future rate impacts.

We note that OPC suggested that we limit our approval of recovery from the RMP deferred balance in 2012 to no more than $60 million due to current economic conditions. Limiting recovery in 2012 to $60 million is also supported by SACE, FIPUG and PCS Phosphate.

In response to questions during cross examination, PEF witness Foster agreed that a $60 million dollar recovery in 2012 would result in a reduction to a thousand-kilowatt hour residential customer bill of $1.75 per month during 2012 when compared to PEF's request. We note that the Levy portion of PEF's 2012 request would result in a $4.47 monthly residential bill impact. Witness Foster did note that PEF's proposal for 2012 ($4.47) represents a (slightly over 10 percent) reduction in the recovery factor for Levy as compared to the factor currently in place.

We note that OPC's suggestion would result in a significant reduction ($1.75) in the 2012 CCRC factor compared to PEF's proposal. OPC's suggestion, however, could (all other things being equal) result in an estimated cumulative additional pressure on monthly rates in 2013 and 2014 of approximately $1.93. According to witness Elnitsky, under PEF's current plan, spending will increase on the LNP in these years due to the issuance of the full notice to proceed to construct the LNP.

We find that OPC's suggestion, and PEF's proposal, is not inconsistent with our original objective for approving the RMP, that being managing rate impacts over time. Given this, we could approve either approach. In general, we note the primary difference between the two proposals is that OPC's position appears to value current reductions over future rate impacts, whereas PEF's proposal values reductions in future rate impacts over current reductions.

We find that that OPC's suggestion of limiting current recovery from the RMP deferred balance is more effective at managing near term rate impacts. Therefore, we approve OPC's proposal. Thus, we approve a withdrawal of no more than $60 million from the RMP deferred balance, and $15.1 million in associated carrying cost for inclusion in the 2012 NCRC recovery factor.

XXIX. PEF's Net 2012 Recovery Amount

This is a fall-out issue that reflects our decisions on all prior issues. We note that PEF's recoverable amounts for the CR3 Uprate project were stipulated and we approved the stipulation at hearing. Pursuant to the stipulation, PEF will forego collection of $500,000 in project management costs. The $500,000 adjustment was a one-time reduction to the 2009 capital costs. The amount, after adjustment due to the stipulation, is $117,640,493 ($87,028,310 jurisdictional). The effect of this restatement of the 2009 CR3 Uprate CWIP balance will impact the calculation of carrying costs for 2009, 2010, and 2012. These carrying cost impacts, pursuant to the stipulation, will be reflected as a true-up in PEF's March 2012 filings.

Consistent with our findings on the LNP issues, and our prior actions concerning CR3 Uprate issues, we find that $85,951,036 ($140,919,397- ($114,968,361+$60,000,000)) shall be approved as the 2012 NCRC recovery amount. Therefore, we approve a total jurisdictional amount of $85,951,036 for the 2012 NCRC recovery amount. This amount shall be used in establishing PEF's 2012 Capacity Cost Recovery Clause factor.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the stipulations and findings set forth in the body of this Order are hereby approved. It is further

ORDERED that all matters contained in the attachments appended hereto are incorporated herein by reference. It is further

ORDERED that Florida Power & Light Company is hereby authorized to include the nuclear cost recovery amount of $196,088,824 to be used in establishing its 2011 capacity cost recovery factor. It is further

ORDERED that Progress Energy Florida, Inc. is hereby authorized to include the nuclear cost recovery amount of $85,951,036 to be used in establishing its 2011 capacity cost recovery factor. It is further

By ORDER of the Florida Public Service Commission this 23rd day of November, 2011.

Hong Wang

HONG WANG
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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Attachment A:

ISSUE: Should the Commission defer its decision regarding the long-term feasibility of completing the Crystal River Unit 3 (CR3) Extended Power Uprate (EPU) project and the reasonableness of PEF's 2011 and 2012 ongoing construction expenditures, including associated carrying charges?

STIPULATION: This issue is moot because on August 10, 2011, the Commission voted to approve PEF's motion requesting deferral of the Commission's review of the long-term feasibility of completing the CR3 Uprate until the 2012 NCRC proceedings. (TR 21-25)

ISSUE: Should the Commission approve what PEF has submitted as its 2011 annual detailed analysis of the long-term feasibility of completing the CR3 EPU project, as provided for in Rule 25-6.0423, F.A.C? If not, what action, if any, should the Commission take?

STIPULATION: Resolution of this issue is deferred because on August 10, 2011, the Commission voted to approve PEF's motion requesting deferral of the Commission's review of the long-term feasibility of completing the CR3 Uprate until the 2012 NCRC proceedings.

ISSUE: What system and jurisdictional amounts should the Commission approve as reasonable actual/estimated 2011 costs and estimated true-up amounts for PEF's CR3 EPU project?

STIPULATION: On August 10, 2011, the Commission voted to approve PEF's motion requesting deferral of the Commission's review of the reasonableness of PEF's 2011 and 2012 CR3 Uprate expenditures and associated carrying costs until the 2012 NCRC proceedings. The following position excludes PEF's estimated 2011 CR3 Uprate expenses and associated carrying costs. The approved amounts shown for 2011 are a result of the true-up process of costs incurred prior to 2011.

PEF Position B: Consistent with PEF's motion for deferral filed July 1, 2011, which used PEF's response to Staff POD 1 Question 3 as the basis for the revenue requirement calculation updated for changes as identified in the motion: PEF is not requesting a review of reasonableness of capital spend at this time.

O&M Costs (System) $0; (Jurisdictional, net of joint owners) $75 prior period credit. Carrying Costs $12,920,780 and a base revenue requirement credit of $3,176,396.

The Commission should also approve an estimated 2011 EPU project true-up over- recovery of $4,127,377 to be included in setting the allowed 2012 NCRC recovery. The 2011 variance is the sum of an O&M over-projection of $423,168, plus an under-projection of carrying charges of $2,896,951 plus an over-projection of other adjustments of $6,601,160.

ISSUE: What system and jurisdictional amounts should the Commission approve as reasonably projected 2012 costs and for PEF's CR3 EPU project?

STIPULATION: On August 10, 2011, the Commission voted to approve PEF's motion requesting deferral of the Commission's review of the reasonableness of PEF's 2011 and 2012 CR3 Uprate expenditures and associated carrying costs until the 2012 NCRC proceedings. (TR 21-25) The following position excludes PEF's projected 2012 CR3 Uprate expenses and associated carrying costs. The approved amounts shown for 2012 are a result of the true-up process of costs incurred prior to 2011.

PEF Position B: Consistent with PEF's motion for deferral filed July 1, 2011, which used PEF's response to Staff POD 1 Question 3 as the basis for the revenue requirement calculation updated for changes as identified in the motion: PEF is not requesting a review of reasonableness of capital spend at this time.

O&M Costs (System) $0; (Jurisdictional, net of joint owners) $710 prior period credit. Carrying Costs $12,875,746 and a base revenue requirement credit of $3,261,939.

Attachment B:

Approved CR3 Uprate Stipulation

1. As a compromise in settlement, Progress (PEF) agrees to permanently forgo collection of $500,000 in Project Management Costs to resolve Issue 31. This adjustment will be recognized in the order issued in Docket 110009-EI, but the full revenue requirement effect will be reflected as a true-up in the March 2012 NFRs.

2. For 2009 & 2010 CR3 EPU project costs, the parties do not object to the Commission making a final prudence determination for those costs pursuant to Sections 366.93 and 403.519(4), Fla. Stat. in the 2011 NCRC docket. In so agreeing, the parties maintain and do not waive, concede, or give up their right to offer any testimony in any other FPSC docket, nor do they waive, concede, or give up any remedy at law that may exist in any other docket.

ISSUE: For the years 2009 and 2010, should the Commission find PEF reasonably and prudently managed its Crystal River Unit 3 Uprate license amendment request? If not, what dollar impact did these activities have on 2009 and 2010 incurred costs?

STIPULATION: PEF, OPC, SACE, FEA, FIPUG, PCS:

Pursuant to the stipulation entered August 15, 2011, as a compromise in settlement, Progress Energy Florida (PEF) agrees to permanently forgo collection of $500,000 in Project Management Costs to resolve Issue 31. This adjustment will be recognized in the order issued in Docket 110009-EI, but the full revenue requirement effect will be reflected as a true-up in the March 2012 NFRs. This agreement resolves this issue.

For 2009 & 2010 CR3 EPU project costs, the parties do not object to the Commission making a final prudence determination for those costs pursuant to Sections 366.93 and 403.519(4), Fla. Stat. in the 2011 NCRC docket. In so agreeing the parties maintain and do not waive, concede, or give up their right to offer any testimony in any other FPSC docket, nor do they waive, concede, or give up any remedy at law that may exist in any other docket.

ISSUE: Should the Commission find that for 2010, PEF's project management, contracting, accounting and cost oversight controls were reasonable and prudent for the CR3 EPU project? If not, what action, if any, should the Commission take?

PEF:
Yes, PEF's project management, contracting, accounting and cost oversight controls were reasonable and prudent for the CR3 Uprate. These procedures are designed to ensure timely and cost-effective completion of the project. They include regular status meetings, both internally and with its vendors. These

project management and oversight controls also include regular risk assessment, evaluation, and management. There are also adequate, reasonable policies regarding contracting procedures. The Company also has appropriate, reasonable project accounting controls, project monitoring procedures, disbursement services controls, and regulatory accounting controls. Pursuant to these controls, PEF regularly conducts analyses and reconciliations to ensure that proper cost allocations and contract payments have been made. (Garrett, Franke).

OPC, SACE, FEA, FIPUG, PCS:
Pursuant to the stipulation entered August 15, 2011, no position.

ISSUE: What system and jurisdictional amounts should the Commission approve as PEF's 2009 and 2010 prudently incurred costs for the Crystal River Unit 3 Uprate project?

PEF:
2009:
Capital Costs (System) $117,640,493; (Jurisdictional, net of joint owners) $87,028,310

O&M Costs (System) $821,773; (Jurisdictional, net of joint owners) $762,529 Carrying Costs $14,351,595 and a base revenue requirement of $396,018.

The over recovery of $244,745 should be included in setting the allowed 2011 NCRC recovery. The 2009 variance is the sum of an O&M over-projection of $9,999, under-projection of carrying charges of $122,005 and an over-projection of adjustments of $356,771. (Garrett, Franke)

2010:
Capital Costs (System) $45,544,492; (Jurisdictional, net of joint owners) $40,179,535

O&M Costs (System) $917,972; (Jurisdictional, net of joint owners) $823,467 Carrying Costs $10,106,450 and a base revenue requirement credit of $2,901,536.

The under recovery of $108,602 should be included in setting the allowed 2012 NCRC recovery. The 2010 variance is the sum of an O&M over-projection of $286,017, under-projection of carrying charges of $2,549,380 and an over-projection of other adjustments of $2,154,760. (Garrett, Franke).

Pursuant to the stipulation entered August 15, 2011, as a compromise in settlement, Progress Energy Florida (PEF) agrees to permanently forgo collection of $500,000 in Project Management Costs to resolve Issue 31. This adjustment will be recognized in the order issued in Docket 110009-EI, but the full revenue requirement effect will be reflected as a true-up in the March 2012 NFRs.

PEF, OPC, SACE, FEA, FIPUG, PCS:
Pursuant to the stipulation entered August 15, 2011, the parties do not object to the Commission making a final prudence determination for 2009 and 2010 CR3 EPU costs pursuant to Sections 366.93 and 403.519(4), Fla. Stat. in the 2011 NCRC docket. In so agreeing the parties maintain and do not waive, concede, or give up their right to offer any testimony in any other FPSC docket, nor do they waive, concede, or give up any remedy at law that may exist in any other docket.