BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida, Inc.	DOCKET NO. 090079-EI
In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.	DOCKET NO. 090144-EI
In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.	DOCKET NO. 090145-EI ORDER NO. PSC-10-0131-FOF-EI ISSUED: March 5, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. ALEXANDER GLENN, JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042; JAMES MICHAEL WALLS, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239; RICHARD D. MELSON, ESQUIRE, 705 Piedmont Drive, Tallahassee, Florida 32312
On behalf of Progress Energy Florida, Inc. (PEF).

CHARLES REHWINKEL, Associate Public Counsel, CHARLIE BECK, Deputy Public Counsel, and PATRICIA A. CHRISTENSEN, Associate Public Counsel, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

STEPHANIE ALEXANDER, ESQUIRE, 200 West 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the Florida Association for Fairness in Rate Making (AFFIRM).

CECILIA BRADLEY, Office of the Attorney General, The Capitol – PL01, Tallahassee, FL 32399
On behalf of the Office of the Attorney General (AG).

JON MOYLE, JR, and VICKI GORDON KAUFMAN, ESQUIRES, 118 North Gadsden Street, Tallahassee, Florida 32312 and JOHN W. McWHIRTER, JR., ESQUIRE, P.O. Box 3350, Tampa, Florida
On behalf of the Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Young van Assenderp, P.A., 225 South Adams Street, Suite 200, Tallahassee, Florida 32301
On behalf of the Florida Retail Federation (FRF).

AUDREY VAN DYKE and ELLEN EVANS, Naval Facilities Engineering Command, Litigation Headquarters, 720 Kennon Street, S.E. Building 36, Room 136, Washington Navy Yard, DC 20374
On behalf of the Navy (NAVY).

JAMES W. BREW and F. ALVIN TAYLOR, ESQUIRES, Brickfield, Burchette, Ritts and Stone, P.C., 1025 Thomas Jefferson St., N.W., Eighth Floor, West Tower, Washington, D.C. 20007
On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS PHOSPHATE or PCS).

KATHERINE E. FLEMING, CAROLINE M. KLANCKE, KEINO YOUNG, and ERIK L. SAYLER, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (STAFF).

FINAL ORDER DENYING RATE INCREASE

BY THE COMMISSION:

BACKGROUND

This proceeding commenced on March 20, 2009, with the filing of a petition for a permanent rate increase by Progress Energy Florida, Inc. (PEF or Company). The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to the jurisdiction of this Commission. PEF's service area comprises approximately 20,000 square miles in 35 of Florida's counties. PEF serves more than 1.6 million retail customers.

PEF requested an increase in its retail rates and charges to generate $499,997,000 in additional gross annual revenues. This increase would allow the Company to earn an overall rate of return of 9.21 percent or a 12.54 percent return on equity (range 11.54 percent to 13.54 percent). The Company based its request on a projected test year ending December 31, 2010. PEF stated that this test year is the appropriate period to be utilized because it represents the conditions to be faced by the Company, and is representative of the customer base, investment requirements, and overall cost of service to be realized for the period when the new rates will be in effect.

PEF also requested an interim rate increase in its retail rates and charges to generate $13,078,000 in additional gross annual revenues. This increase would allow the Company to earn an overall rate of return of 7.84 percent or a 10.00 percent return on equity. The Company based its interim request on a historical test year ended December 31, 2008. Order No. PSC-09-0413-PCO-EI, issued June 10, 2009, in Docket No. 090079-EI, suspended the proposed final rates and granted a $13,078,000 interim rate increase.

The Office of the Public Counsel (OPC),[1] the Office of the Attorney General (AG),[2] the Florida Industrial Power Users Group (FIPUG),[3] the Florida Retail Federation (FRF),[4] the Florida Association for Fairness in Rate Making (AFFIRM),[5] the Navy (NAVY),[6] and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS)[7] intervened in this proceeding.

By Order No. PSC-09-0415-PAA-EI,[8] issued June 12, 2009, Docket No. 090144-EI was consolidated with Docket No. 090079-EI. In addition, Order No. PSC-09-0586-PCO-EI,[9] issued August 31, 2009, consolidated Docket No. 090145-EI with Docket No. 090079-EI.

Ten customer service hearings were held at the following locations and dates: Lake Wales, July 7, 2009; New Port Richey, July 8, 2009; Live Oak, July 9, 2009; Lake Mary, July 15, 2009; St. Petersburg, July 16, 2009; Clearwater, July 16, 2009; Ocala, July 17, 2009; Citrus County, July 17, 2009; Apalachicola, July 30, 2009; and Tallahassee, September 21, 2009. The Technical Hearing was held in Tallahassee on September 21-25, 28-30, 2009 and October 1, 2009.

On October 2, 2009, Governor Charlie Crist sent a letter requesting that we postpone our decision on the rate increase until the two newly appointed Commissioners took office. All parties were invited to brief this Commission on the topics of whether we could postpone the

[1] Order No. PSC-09-0105-PCO-EI, issued February 23, 2009.
[2] Order No. PSC-09-0122-PCO-EI, issued March 2, 2009.
[3] Order No. PSC-09-0198-PCO-EI, issued April 1, 2009.
[4] Order No. PSC-09-0199-PCO-EI, issued April 1, 2009.
[5] Order No. PSC-09-0579-PCO-EI, issued August 27, 2009.
[6] Order No. PSC-09-0399-PCO-EI, issued June 6, 2009.
[7] Order No. PSC-09-0200-PCO-EI, issued April 1, 2009.
[8] Order No. PSC-09-0415-PAA-EI, issued June 12, 2009, in Docket No. 090144-EI, In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.
[9] Order No. PSC-09-0586-PCO-EI, issued August 31, 2009, in Docket No. 090145-EI, In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.

decision on the rate case, and whether PEF could implement rates, subject to refund. Order No. PSC-09-0753-PCO-EI, issued November 16, 2009, in this docket, recognized that PEF could increase its rates on January 1, 2010, subject to refund. However, we requested and directed PEF to do everything that it could to minimize any potential impact on ratepayers in the short-term.

In response to our request, PEF filed a Motion for Expedited Approval of a Regulatory Asset or Liability as an Alternative to Implementing Rates Subject to Refund Pursuant to Section 366.06(3), F.S., (Motion) on November 2, 2009. OPC filed a response to PEF's Motion on November 9, 2009. By Order No. PSC-09-0819-PCO-EI, issued December 14, 2009, we approved PEF's request for approval of a regulatory asset or liability. This order addresses PEF's requested permanent rate increase. We have jurisdiction pursuant to Sections 366.041, 366.06, 366.07, and 366.071, F.S.

DECISION

I. APPROVED STIPULATIONS

We have previously approved several stipulated issues. The stipulated issues are reflected below, as well as in a consolidated list attached hereto as Appendix 1.

II. TEST PERIOD AND FORECASTING

A. Test Period

We find that the twelve months ended December 31, 2010 is the appropriate test year.

B. Appropriate Inflation, Customer Growth and Other Trend Factors

We find that the appropriate inflation, customer growth and other trend factors for use in forecasting are those included in the MFRs, as filed.

C. Forecasts of Customer Growth

We find that PEF's forecasts of customer growth, KWH by revenue class, and system KW for the projected test year are appropriate.

D. PEF's Billing Determinants

We find that PEF's forecasts of billing determinants by rate class for the projected test year are appropriate.

III. QUALITY OF SERVICE

PEF's distribution system delivers power to approximately 1.6 million customers across a service area that is over 20,000 square miles. The system includes 18,000 circuit miles of overhead primary voltage distribution conductors, approximately 13,000 miles of underground primary voltage distribution cable, distribution substations and related poles, transformers, cables, wires, and other material and equipment ranging from bucket trucks to pickup trucks.

The quality and reliability of the electric service provided by a utility is objectively measured through the use of electric industry reliability indices and the number and types of customer complaints. We have established specific requirements and reliability indices for both the transmission and distribution system of a utility (found within Rule 25-6.0455, F.A.C.). The reliability indices track the duration and frequency of power interruptions and are typically examined at a system level. System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) are the most common indices, and are measures of unreliability such that as the indices increase, reliability becomes increasingly worse. All of the indices provide information about average system performance over a specific time period and that it is best to examine the current results of a single utility and to make a determination as to whether the trend of the current and past results are improving or worsening. However, using averages as the sole basis for decision making can mask the interruption for a specific customer. In determining the reliability and adequacy of PEF's electric service, staff notes that PEF's service territory covers approximately 20,000 square miles and that the utility serves over 1.6 million customers. Therefore, an individual customer's outage experience is averaged within the system indices.

Service Hearings and Complaints

The AG approached the determination of PEF's service quality and reliability from the single dimension of customer satisfaction/complaints, whereas FRF included objective measurements of system service reliability and customer satisfaction. Both parties argued that the J.D. Power and Associates Report for customer satisfaction indicated that PEF had a rating of 619, whereas Progress Energy Carolinas had a rating of 657 and that the relative position of PEF below Progress Energy Carolinas is significant. We find it extremely difficult to compare utilities in two different states and believe that the numbers serve to merely rank the companies among other utilities regarding customer satisfaction and that no determination was made as to whether the service reliability was adequate. Witness Dolan testified that PEF was in the first or second quartile of residential customer satisfaction for the past six years according to the J.D. Power and Associates Report. FRF does conclude that the objective measurements of service reliability indicate that PEF is providing adequate service reliability.

The AG argued that customers should not have to come to a public service hearing to have their complaints heard. Approximately 300 customers expressed their displeasure with either PEF's requested rate increase or problems with PEF's electric service. The electric service related problems involved 18 customers. We agree with the AG to the extent that customers should not have to appear at a public service hearing to have their complaints heard. The typical customer complaint is either handled directly by PEF and its customer service agents or as staff witness Hicks testified by this Commission's Bureau of Consumer Assistance. The function of the Bureau of Consumer Assistance is to resolve disputes between regulated companies and its customers. In her testimony, witness Hicks identified several programs for complaint resolution other than PEF's service hearings. These included the Commission's Transfer-Connect (Warm Transfer) System and the Consumer Activity Tracking System that logs and tracks the customer's complaint until it is resolved. The Transfer Connect system allows the Commission to put the customer in immediate contact with the Utility's customer service personnel. In response to the service hearings, PEF filed a Customer Service Hearing Report to document the corrective actions taken.

PEF witness Joyner explained several customer service complaints from PEF's service hearings and in reference to the Clearwater Service Hearing, he stated that PEF met with the individual experiencing surge related issues and offered to change out his service drop. Witness Joyner also stated that in the Lake Mary Service Hearing a customer alleged that a computer was damaged by PEF because of momentary interruptions. The investigation revealed that the customer was participating in PEF's Meter Base Protection (MBP) program and that the customer had a large scale suppression device on the meter base, but that the small appliance (computer) did not have an individual surge suppressor. The meter base protection mitigates power surges of a large scale; however, individual suppressors are still recommended for those high voltage spikes that on occasion make it through the meter base protector. We note that there is a difference between power surges which may occur due to lightning strikes and momentary interruptions. The momentary interruptions are typically caused by tree branches striking the line, an animal contacting a live circuit, equipment failure, or an automobile hitting a pole. Power surges cause an increase in voltage whereas a momentary interruption causes a loss of power. In this complaint and for every complaint, witness Joyner testified there are direct standards in which PEF will be held accountable for a claim. He also stated the investigation is the actual determinate of the claim and not whether the customer had two levels of surge suppression. The AG argued that two of PEF's witnesses testified to different procedures for processing a claim. Staff agrees that there are different procedures, one for processing claims made to PEF for customers that are participants in the MBP program and customers that are filing a claim. However, as witnesses Dolan and Joyner testified, the claim investigation is the ultimate determinate as to whether PEF will pay a claim.

Additional service issues included outages purported to be caused by the lack of tree trimming. Witness Joyner stated that there were cases where PEF had scheduled tree trimming based upon its cyclic schedule for vegetation management and that in several cases the tree trimming was scheduled for the first half of 2010. PEF indicated that all of the service related problems identified at the customer service hearings were corrected by PEF.

Staff witness Hicks provided Exhibits 206 and 207 concerning customer complaints reported to this Commission for a two year period from July 1, 2007 to June 30, 2009. She stated that 4,386 of the 5,611 complaints were warm-transferred directly to PEF for resolution via the Commission's Transfer Connect Program. Approximately 37 percent or 2,052 of the total complaints were service quality issues. An analysis of the PEF's service reliability complaints in Appendix B of the Commission's annual report "Review of Florida's Investor-Owned Electric Utilities' Service Reliability in 2007" indicates that the service reliability complaints since 2004 are trending downward. The service reliability complaints were categorized and included service interruptions, quality of service, repair, safety, and trees.

We do not discount the importance of each customer comment and problem expressed at the service hearings or recorded in the docket file; however, the overall number of service reliability related complaints has decreased since 2004. We believe the customer complaints are reflected in the reliability indices known as SAIDI, SAIFI and CAIDI recorded in PEF's distribution system. The electric utility indices described below are required by Rule 25-6.0455, F.A.C., and include a trend analysis for a five year period from 2004 through 2008.

Reliability Indices

The electrical system reliability indices are identified by acronyms and each is the result of a mathematical computation. PEF presented indices for both the transmission system and the distribution system. The transmission system was evaluated using several indices. First, the Circuit System Average Interruption Duration Index or Circuit-SAIDI tracks the average duration of a transmission system outage. Second, the System Average Interruption Frequency Index or SAIFI tracks the average frequency (number) of transmission caused outages. Third, the System Average Interruption Frequency Index for Momentary interruptions or SAIFI-M tracks the average frequency of transmission caused outages of less than a minute. Finally, the System Average Restoration Index or SARI, tracks the time required to re-energize the circuits following an outage. No party disputed witness Oliver's testimony that PEF's transmission system reliability indices had across the board improvements for the five year period beginning in 2003 and concluding in 2007.

Witness Joyner provided the indices that were used to evaluate the distribution system: SAIDI, the System Average Interruption Duration Index is calculated by dividing the customer minutes of interruption (CMI) by the number of customers (C) served by the system (SAIDI = CMI ÷ C). SAIFI, the System Average Interruption Frequency Index is calculated by dividing the number of service interruptions (CI) by the number of customers (C) served (SAIFI = CI ÷ C). CAIDI is the last index and it is known as the Customer Average Interruption Duration Index. CAIDI is calculated by dividing the total system customer minutes of interruption (CMI) by the number of interrupted customers (CI), (CAIDI = CMI ÷ CI).

PEF witness Joyner identified two additional programs, Customer Reliability Excellence Monitor (CREM) and Commitment to Excellence (CTE) that are utilized by the utility in determining electric reliability. The CREM program appears to be more customer oriented than the Commission's reporting requirements in that CREM tracks service interruptions for customers that experience more than four momentary interruptions on a yearly basis; whereas, the Commission requires that the IOUs report customer interruptions that are greater than five momentary interruptions. For those customers experiencing multiple momentary interruptions, triggering reporting on four interruptions versus five allows the Company to assess the impact of momentary interruptions sooner in order to maintain the overall system reliability.

PEF also utilizes goal setting for one of its distribution reliability indices. PEF set the SAIDI goal for the distribution system to 80 minutes in order to ensure that PEF is providing reliable distribution service. We believe this is a noteworthy approach and that goal setting appears to benefit PEF's customers by maintaining the SAIDI below 80 minutes for the past five years as seen in Figure 1 below.

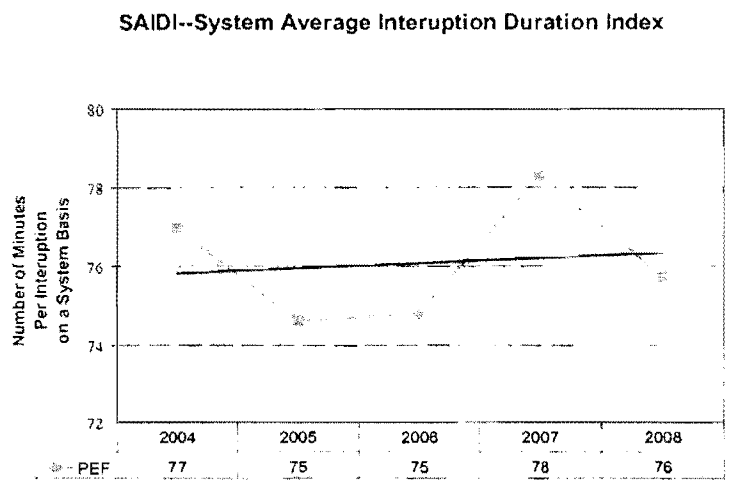

Figure 1 SAIDI

Figure 1 illustrates the average length of time, in minutes, for an outage or interruption on PEF's distribution system. For example, in 2004, when an outage on the system occurred, the outage would last an average of 77 minutes. The years 2005 through 2008 are also between 74 and 78 minutes. Plotting a linear trend line from the data indicates the SAIDI trend is relatively flat across the 76 minute axis. We conclude that when an outage occurs on PEF's distribution system, the length of time for the outage has remained fairly stable over the last five years. This is indicated by the trend line along the 76 minute axis.

The average number of interruptions on the distribution system is graphically illustrated in Figure 2. The SAIFI index is relatively flat and is trending downward for the last five years. The numbers of interruptions a customer experiences, on average, has steadily decreased from 1.19 interruptions in 2004 to 1.05 in 2008.

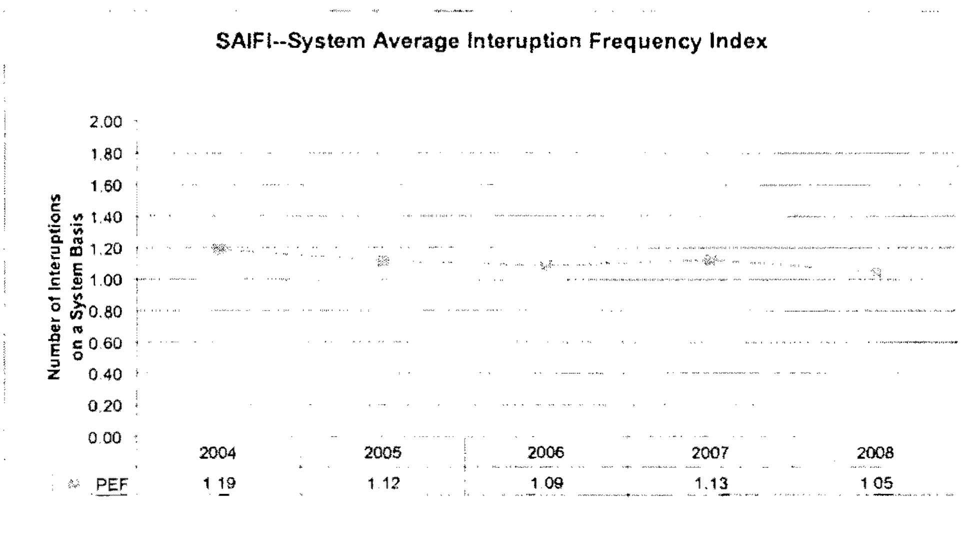

Figure 2 SAIFI

A graphical analysis of CAIDI, shown in Figure 3, indicates that the duration of a customer's average interruption has increased from a low of 65 minutes in 2004 to a high of 72 minutes in 2008. The CAIDI index is slightly increasing for the last five years; however, in 2006 and 2007 it remained unchanged. Staff also examined the data found in the "Review of Florida's Investor-Owned Electric Utilities' Service Reliability in 2007." Plotting a CAIDI trend line for the period of 1997 through 2008 indicates that CAIDI is trending downward. The 1997 CAIDI was reported as 75, in 2008 the CAIDI was reported as 72 and the highest CAIDI reported between 1997 and 2008 was recorded in the year 2000 which was 75.4 minutes. We believe that examining a broad range of years (5 to 10) is appropriate when trying to assess an electric utility's system reliability. The determination of the adequacy of PEF's service quality and reliability involves more than a single dimension or index. All of the indices for the distribution system and the transmission system coupled with PEF's customer service complaints indicate the adequacy of PEF's service quality and reliability.

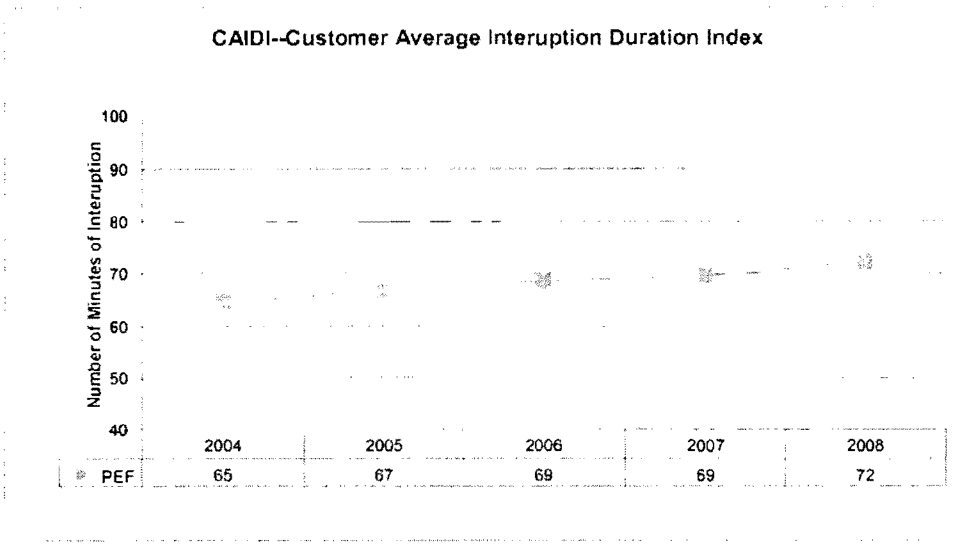

Figure 3 CAIDI

Conclusion

Based upon the analysis of customer complaints, the objective measurements of the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), the Customer Average Interruption Duration Index (CAIDI) relating to PEF's distribution system, and the four indices for the transmission system that include Circuit-SAIDI, Transmission-SAIFI, Momentary interruptions or SAIFI-M, and the System Average Restoration Index (SARI), we find that the quality and reliability of the electric service provided by PEF is adequate.

IV. DEPRECIATION STUDY

A. Depreciation Rates, Cost Recovery Schedules, and Amortization Schedules

We find that the current-approved depreciation rates, capital recovery schedules, and amortization schedules should be revised. The parties' positions on how they should be revised are set forth in subsequent issues.

B. Capital Recovery Schedules

Under the capital recovery schedule mechanism, the investment and associated reserve of installations facing near-term retirement are separated out as sub-accounts, and the unrecovered net amounts are amortized over the period of their remaining service to the public. The mechanism has been in our depreciation rules, and has been our standard practice for over 20 years. PEF witness Robinson asserted that capital recovery schedules are not needed; remaining life will provide full recovery. We agree that remaining life will provide recovery over the remaining life of the given account or the given group of assets. However, to the extent a company's planning changes, so should the remaining period of recovery.

The purpose of depreciation is to match expenses to the period the assets associated with those expenses are providing service to the public. Under group depreciation, it is recognized that some assets within the group will experience a life shorter than the average while others will experience a life longer than the average. However, if there is a group of assets planned for near-term retirement that now have a significantly shorter life than the overall group life, the associated investments should be withdrawn from the group and recovered over their expected life as provided by our rules.

The record in this proceeding shows that the remaining life mechanism is designed to recover the net investment over the remaining life of the group or account. We believe that recovery over the remaining period of service is in fact the remaining life methodology. This is the principle of matching expenses to consumption. If assets retire earlier than the average life of the group without recovery afforded, a negative reserve component is created. The negative reserve component translates into a positive rate base element. From the Company's standpoint, it will continue to earn a return on this non-existent plant over the life of the group. From the ratepayers' standpoint, they will continue paying for plant no longer providing service until the situation is corrected. Negative reserve amounts are non-life related net investments that the Commission has historically corrected as fast as practicable to remedy the existing intergenerational inequity.[10]

Utilities are required by Rule 25-6.0436, F.A.C., to file a depreciation study at least once every four years from the date of the last filed study. Because of rate case settlements in 2002 and 2005, the last depreciation study for PEF (then Florida Power Corporation, FPC) that underwent our review was in 1997. In that case, the Company itself proposed capital recovery schedules, clearly recognizing the advantage of our provided mechanism. In FPC's 1997 depreciation study,[11] revised depreciation rates and recovery/amortization schedules were approved for FPC, with an effective date of January 1, 1998. The Company's proposed recovery schedule concerning the net unrecovered assets of the Suwannee River Steam Production units was approved. In this instance, a four-year amortization, representing the time period between depreciation studies, was approved, even though Company planning indicated continued operation through 1999. Two additional recovery schedules were approved and related to the recovery of assets that were not viable for reuse with the repowering of the Higgins and Turner

[10] Order No. PSC-09-0229-PAA-GU, issued April 13, 2009, in Docket No. 080548-GU, In Re: 2008 depreciation study by Florida Public Utilities Company, p. 3; Order No. PSC-03-0260-PAA-GU, issued February 24, 2003, in Docket No. 010906-GU, In re: Request for approval of depreciation study for five-year period 1996 through 2000 by Sebring Gas System, Inc., p. 3; Order No. PSC-02-1492-PAA-GU, issued October 31, 2002, in Docket No. 010383-GU, In re: Application for approval of new depreciation rates by Tampa electric Company d/b/a Peoples Gas System, p. 3; Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 010669-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities Company, p. 2.

[11] Order No. PSC-98-1723-FOF-EI, issued December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study for Florida Power Corporation. (FPC 1997 Depreciation Study).

plants. The approved recovery period for these schedules represented the "remaining service period of the related assets."[12]

In the instant case, PEF has not proposed any capital recovery schedules. In response to discovery, PEF asserted that the Bartow Steam Units 1-3 are now planned for retirement in 2009 rather than 2016. PEF stated that it "is proposing updated Steam Production depreciation rates which when adopted will effectively recover the remaining unrecovered net investment associated with these retired assets over the useful life of the plants in the Steam Production depreciation group." Thus, PEF proposed that the recovery of the net investments no longer providing service be over the remaining life of the all steam production plant, including the new replacement plant. When our staff inquired through discovery about PEF's planning for near-term retirements in connection with major upgrades or overhauls, a satisfactory response was not provided. PEF objected to the request and identified only upgrades taking place in 2010. We are puzzled by PEF's attitude concerning a mechanism that is intended to work in conjunction with remaining life and ensure full recovery.

We note that Table 5F-Future (Pro Forma) of PEF's depreciation study shows several accounts with estimated negative reserves as of December 31, 2009. According to PEF witness Robinson, the negative reserve for Avon Park, Account 311, was an error and should be negative $5,410,811. The negative reserve amounts for Bartow, Accounts 311, 312, 314, and 316, are due to the unrecovered amounts at its 2009 retirement. Witness Robinson admits that these negative reserve amounts are not associated with plant that is serving the public. These negative amounts are associated with investments retired earlier than provided in the remaining life rate design. These unrecovered amounts create positive rate base components, upon which the Company continues to earn a return. Witness Robinson commented that the Bartow Steam unrecovered amounts are being distributed to the other properties within the plant account and recovered over the remaining life of the applicable group. This action was not specifically proposed or discussed in the depreciation study. Witness Robinson's proposal will ultimately recover the negative reserve amounts, but that recovery will be over the remaining life of all accounts. We believe that these unrecovered costs associated with the repowering of Bartow do not relate to the peaking or new combined-cycle plants. In this case, these assets will be recovered after they have been retired and are no longer serving the public. We believe that deferring recovery to the future is not good depreciation practice and is tantamount to mortgaging the future. We believe these net investments should be recovered as fast as practicable. As discussed in further detail later in this order, we believe a portion of the reserve surplus existing in PEF's production plants can be used to fully recover these unrecovered costs associated with the retirement of the Avon Park and Bartow steam plants.

Crystal River Units 4 and 5 (CR 4 & 5) are in the process of a major upgrade that will be completed in 2010. The upgrade includes adding a flue gas desulfurization system and scrubber at the units. As a result of the upgrade, PEF has identified investments of $21.2 million that will retire in 2009. The reserve associated with these investments is $15.3 million, resulting in a net unrecovered amount of $5.9 million as of December 31, 2009. We find that a portion of the

[12] Id., p. 8.

reserve surplus existing in the production accounts discussed later in this order shall be used to recover the associated unrecovered costs relating to plant no longer providing service.

In response to discovery, PEF identified $15.2 million retiring associated with the steam generator replacements at Crystal River Unit 3 (CR3) in 2009.[13] The projected estimated reserve at retirement is $12.6 million, not including removal costs. We believe the $2.6 million unrecovered cost should be recovered ideally over the remaining period in service. In this case, however, new depreciation rates are being prescribed effective January 1, 2010, after the generator's retirement. For this reason, this net unrecovered investment relates to plant no longer in service. These unrecovered net investments should be recovered as fast as practicable as they represent plant no longer in service and, like the Bartow retirements, result in a negative rate base component. We find that a portion of the reserve surplus existing in the nuclear production function shall be used to recover the associated retiring steam generator net investments.

PEF's depreciation study also identified a negative reserve for Account 370, Meters, in the amount of $11,443,192, and Account 396, Power Operated Equipment, in the amount of $3,221,612. The negative reserve for Meters is the result of the Automatic Meter Reading (AMR) upgrades that occurred in 2006. For Account 396, Power Operated Equipment, the specific cause for the account's negative reserve is not known and is not addressed in PEF's depreciation study. Nevertheless, both negative reserve amounts represent plant no longer providing service to the public, and thus recovery through a capital recovery schedule is necessary. Recovery of net investments such as these should be recovered as fast as practicable. As discussed in further detail later in this order, we find the reserve surplus existing in other distribution accounts can be used to fully recover this negative reserve.

The net unrecovered investments discussed above are associated with plant no longer providing service. Under PEF's proposal, these costs would be recovered over the remaining life of the replacement plant, perhaps as long as 30 years. We believe that ratepayers should not continue to bear the recovery of these costs of plant no longer in service while not receiving any benefits. These costs should be recovered as fast as practicable.

Conclusion

We hereby approve capital recovery schedules to address the net unrecovered investments associated with the retirement of the Avon Park and Bartow steam plants, the upgrade at CR 4 & 5, and the CR 3 steam generator replacement. We also approve recovery schedules to address the negative reserve amounts existing in Meters, Account 370, and Power Operated Equipment, Account 396. We find that existing reserve surpluses in the production plant and the distribution plant functions, as discussed below, can be used for the immediate recovery of the Avon Park, Bartow, CR 4 & 5, CR 3, meter, and power operated equipment unrecovered net investments, respectively.

[13] The new generators are similar in design to the original generators but are constructed with improved materials that will eliminate known failure mechanisms and reduce critical outage impacts.

C. Calculation of the Average Remaining Life

Testimony proffered by PEF and OPC discussed the determination of the remaining life. No other party presented testimony particularly on point with regards to this issue. While the parties disagreed with the assumptions and inputs to be used in the calculation of the remaining life, their positions indicate that they agree that the calculation itself is correct. PEF's assumptions, including life spans, and inputs used in determining its proposed average remaining lives are discussed later in this order. No party refuted PEF's mathematical calculation of remaining life. We reviewed PEF's remaining life calculation in its depreciation study and find that the calculation of the average remaining life is appropriate.

D. Life Spans for Coal Plants

Life spans are used in developing the average remaining lives of PEF's production plants. The life span of a given facility is the difference between the average in-service date and an estimated date of retirement.

We note that the retirement date for Crystal River Units 1 and 2 (CR 1 & 2) is tied to the commercial operation of Levy Unit 2, a PEF planned nuclear unit. For this reason, we find that PEF's retirement date for these units is reasonable to use in determination of the life and salvage parameters for revised depreciation rates.

However, we find that PEF has not supported the life spans for CR 4 & 5 used in the depreciation study. PEF witness Robinson was hired by the Company to perform its depreciation study. While the witness was the sole sponsor of the study, he received additional information from PEF operations personnel relative to plant operations, including the estimated retirement date for each generating unit. Even so, we believe that PEF's depreciation study and its results rest with witness Robinson, PEF's depreciation witness.

Witness Robinson agreed that life spans are important in developing depreciation rates. The witness also acknowledged that PEF's depreciation study did not include substantive information on PEF's generating unit life spans because they were provided by PEF. While the witness could broadly explain how retirement dates are determined, he admitted that these were developed by PEF. Witness Robinson stated that he did not review the life spans provided to him because he was only tasked with performing the depreciation study using the information provided to him. Therefore, we conclude that PEF's depreciation study does not contain persuasive supporting information with regards to its proposed life spans.

PEF witness Crisp provided the only support for PEF's estimated retirement dates and life spans. We observe that the claimed support consists of one page indicating the average in-service date for each generating unit, along with the retirement date assumed in the 2005 depreciation study, the current projected retirement date for use in the instant study, and some broad comments regarding PEF's plant sites. For example, the retirement dates for CR 4 & 5 were extended 14 years, from 2021 until 2035. The extent of PEF's comments for the estimated retirement dates for the Crystal River coal units is "clean air legislation."

As acknowledged by witness Crisp, the specific information supporting PEF's proposed life spans was not specifically identifiable in Exhibit 216; it was embedded in the exhibit but not disclosed discretely and separately. Witness Crisp explained that there are many factors that go into the determination of life spans, including the cost-effectiveness of a given unit and where it fits within certain external drivers, such as climate change, but acknowledged that none of this specific information was discussed in his testimony or his offered support. Absent this substantive information, we are unable to conclude whether or not PEF's life spans are appropriate.

Additionally, while witness Crisp stated that PEF's service lives reflect the optimum time based on its analyses, its Ten-Year Site Plan, and modeling studies, the witness acknowledged that longer life spans as proposed by the intervenors were not considered in PEF's analysis. We observe that it is therefore unknown whether the intervenors' proposed life spans would be optimal for PEF's ratepayers.

We believe that the criticisms PEF waged against the intervenors' proposed life spans can equally apply to PEF. Both OPC witness Pous and FIPUG witness Pollock asserted that based on their review of PEF's depreciation study, they found that the study did not contain specific information with regards to 1) the condition of PEF's generating facilities with respect to their life spans, 2) PEF's expertise in operating or maintaining its generating units, 3) substantiation that PEF has unique load demands or how load demands impact the life spans, 4) updates, changes and reconfigurations made at each plant and how each affects the operating characteristics of the generating units with respect to life spans, 5) how renewable energy requirements may impact the life spans, and 6) the environmental risks PEF faces and how these risks may impact the life spans of the generating facilities. We find that these omissions are compelling, especially given that PEF witness Robinson acknowledged that the depreciation study did not address or analyze such information. We note that PEF's depreciation witness admitted that he had no specific knowledge with regard to any of the items about which the intervenors are criticized. We believe that if PEF had specific information supporting its life spans, it should have provided it in the depreciation study. Rule 25-6.0436, F.A.C., requires that a depreciation study include a justification for a company's proposed depreciation parameters for each study category. This justification includes such things as growth, company planning, technology, physical conditions, and trends.

Based on the foregoing, we believe that PEF's depreciation study is void of any supporting information regarding the life spans for CR 4 & 5 used in the depreciation study. Moreover, we agree that the supporting information provided in response to discovery consisted of conclusory responses without any specific data or analysis to support the life spans. Further, recognizing that PEF itself acknowledged that the actual service life or life span of a generating unit is not actually known until it is retired, we agree with OPC and FIPUG that consideration of life spans used by other electric companies is in order. We find it compelling that PEF did not refute that other utilities use life spans for coal plants in the range of 55 to 65 years. In light of the lack of persuasive PEF-specific information supporting its proposed life spans, we find that OPC's proposed life span of 60 years for CR 4 & 5 is reasonable to use in this proceeding for determining appropriate life parameters for PEF's coal plants.

Conclusion

Accordingly, we find that a 54-year life span shall be used for CR 1 & 2 and a 60-year life span shall be used for CR 4 & 5 for determining appropriate life parameters in this proceeding.

E. Life Spans for Combined Cycle Plants

PEF witness Robinson testified that the estimated retirement dates and life spans for PEF's generating units were determined by the Company's operating and planning management. In the current depreciation study, PEF proposed a 29-year life span for Hines Unit 1, and a 30-year life span for each of the other three combined cycle units at the Hines Energy Center and the new Bartow unit planned for operation in 2009. For Tiger Bay, PEF proposed an estimated retirement date of 2038 and 43-year life span, based in part on the CT rotor replacement that occurred in 2008.

OPC witness Pous and FIPUG witness Pollock testified that PEF's 30-year life span for its combined cycle units is understated. Both witnesses contended that a life span of at least 35 years is more appropriate. Additionally, OPC witness Pous proposed that PEF should be directed to perform a detailed analysis in its next depreciation study demonstrating why its combined cycle generating facilities cannot be expected to operate for 35 years or longer.

FIPUG witness Pollock testified that the life span is the most important assumption in determining appropriate depreciation rates, an assumption not addressed in PEF witness Robinson's depreciation study. Witness Pollock asserted that PEF has not justified its proposed life spans. The witness also stated that PEF has not explained why its combined cycle units cannot operate longer than 30 years, especially given that these units represent the most efficient units on PEF's system.

FIPUG witness Pollock supported his proposed life span by reference to combined cycle life spans used by other utilities that ranged from 35 years to 60 years. Witness Pollock also noted that this Commission approved depreciation rates for Gulf Power Company (Gulf) that were based on a 34-year life span for Gulf's combined cycle units.[14] Both OPC witness Pous and FIPUG witness Pollock asserted that considering life spans approved in other states, as well as the Florida example, demonstrated the unreasonableness of PEF's proposed life spans.

PEF witnesses Robinson and Crisp responded to the recommendations of OPC witness Pous and FIPUG witness Pollock. PEF witness Crisp criticized the OPC and FIPUG proposals, although he had no direct role in preparing PEF's depreciation study. The witness contended that given the small differences between PEF's proposed life spans and those recommended by the intervenors, PEF's life spans should be considered reasonable. Witness Crisp testified that he provided witness Robinson with the "facility service lives of the power plants that were used in the depreciation study." Finally, the witness asserted that PEF's estimated lives for its combined

[14] Order No. PSC-07-0012-PAA-EI, issued January 2, 2007, in Docket No. 050381-EI, In re: Depreciation and dismantlement study at December 31, 2005, by Gulf Power Company, p. 2. (2005 Gulf Power Depreciation Order).

cycle units are "based on PEF's expertise and experience with the condition, operation, and maintenance of these units to meet PEF's load demands under the operational, environmental, and regulatory conditions facing PEF."

PEF witness Robinson testified that he discussed the service lives for PEF's generating facilities with the Company's resource planning group and reviewed the materials they provided. Witness Robinson stated that he visited representative generation plants "to observe field operations and obtain local operating input." The witness contended that OPC witness Pous and FIPUG witness Pollock did not visit PEF's generation facilities and did not consider the operational, environmental, and regulatory conditions in which the Company operates. Witness Robinson claimed that PEF's determination of the retirement dates and service lives for its generating facilities was based on its experience and judgment and was the product of an ongoing, internal management resource planning process. Witness Robinson maintained that there was no reason for him to substitute his judgment for PEF management as to the estimated retirement dates. Witness Robinson also contended that we should not substitute PEF's judgment with those made by the intervenor witnesses based on anecdotal information and generalizations.

Witness Crisp criticized the intervenor witnesses for using only information from other areas around the country that do not correlate to PEF's units and do not correlate to the climate, do not correlate to the operating conditions, do not correlate to the load requirements and do not correlate to the regulatory structure of Florida. The witness explained that PEF developed the projected retirement dates for its generating units in the course of its regular planning process that included 1) the specific current condition of each unit; 2) updates, changes, and reconfigurations made at each plant that affect operating characteristics; 3) complexity of operations and maintenance and longer term validity of the units; 4) subtropical operating environment; and 5) bulk system operating requirements and demands place on the generating plants. These decisions, asserted the witness, reflect PEF's accumulated past and current experience with operating its units under PEF's operating, environmental, and regulatory conditions to meet its load demands. The witness contended that neither OPC witness Pous nor FIPUG witness Pollock has experience with the operations and system planning considerations for PEF and has not visited any of PEF's generating plants. In contrast, the witness asserted, witness Robinson discussed the resource planning process and PEF's "estimated service lives" with PEF resource planning staff. Thus, witness Crisp concluded that there is no reason for the intervenors' judgment to be substituted for PEF's judgment.

In its brief, FRF advocated a 40-year life span for PEF's combined cycle units based on the following reasoning:

- Several of PEF's steam units and combustion turbines on its system have been in service for more than 40 years, and all are projected to be in service longer than 40 years.

- PEF's Ten-Year Site Plan indicated that its non-coal steam units have ages between 35 and 66 years, with the oldest units at the Suwannee station estimated to retire in 2015.

- PEF's simple cycle CT units are between nine years and 41 years of age, with the oldest units being considered for retirement or cold standby status in 2016, at ages approaching 50 years.

FRF argued that if these older technology units have operated for more than 40 years, it then follows that combined cycle units should experience life spans over 40 years. Additionally, FRF pointed out that Gulf, in its 2009 Ten-Year Site Plan, indicated plans to construct and operate a new combined cycle unit with an estimated 40-year life span.

FRF asserted in its brief that PEF's argument that cycling a combined cycle unit shortens its life span is meritless, as PEF witness Crisp testified that many of PEF's generating units have been used for cycling duty over their life spans. With respect to PEF's argument that environmental conditions may result in shorter life spans, FRF argued that this is contradicted by the fact that PEF's steam units at Bartow were over 50 years old when they were retired, and simple cycle CTs that are 37 years old remain at Bartow. FRF argued that this evidence supports a 40-year life span for PEF's combined cycle plants.

As with PEF's coal units previously addressed, we find that PEF has not supported the life spans used in the depreciation study for its combined cycle units. PEF witness Robinson was hired by the Company to perform its depreciation study. While the witness was the sole sponsor of the study, he received additional information from PEF operations personnel relative to plant operations, including the estimated retirement date for each generating unit. Even so, we believe that PEF's depreciation study and its results rest with witness Robinson, PEF's depreciation witness.

Witness Robinson agreed that life spans are important in developing depreciation rates. The witness also acknowledged that PEF's depreciation study did not include substantive information on PEF's generating unit life spans because they were provided by PEF. While the witness could broadly explain how retirement dates are determined, he admitted that these were developed by PEF. Witness Robinson stated that he did not review the life spans provided to him because he was only tasked with performing the depreciation study using the information provided to him. Therefore, we conclude that PEF's depreciation study does not contain supporting information with regards to its proposed life spans.

PEF witness Crisp provided the only support for PEF's estimated retirement dates and life spans. We observe that the claimed support consists of one page indicating the average in-service date for each generating unit, along with the retirement date assumed in the 2005 depreciation study, and the current projected retirement date for use in the instant study. However, as acknowledged by witness Crisp, the specific information supporting PEF's proposed life spans was not specifically identifiable in Exhibit 216; it was embedded in the exhibit but not disclosed discretely and separately. Witness Crisp explained that there are many factors that go into the determination of life spans, including the cost-effectiveness of a given unit and where it fits within certain external drivers, such as climate change, but acknowledged that none of this specific information was in his testimony or the support he offered. Without substantive information supporting PEF's life span determinations, we are unable to conclude whether or not they are appropriate to use in the instant depreciation study.

We believe that the criticisms PEF waged against the intervenors' proposed life spans can equally apply to PEF. Both OPC witness Pous and FIPUG witness Pollock stated that based on their review of PEF's depreciation study, they found that the study did not contain specific information with regards to 1) the condition of PEF's generating facilities with respect to their life spans, 2) PEF's expertise in operating or maintaining its generating units, 3) substantiation that PEF has unique load demands or how load demands impact the life spans, 4) updates, changes and reconfigurations made at each plant and how each affects the operating characteristics of the generating units with respect to life spans, 5) how renewable energy requirements may impact the life spans, and 6) the environmental risks PEF faces and how these risks may impact the life spans of the generating facilities. We find that these omissions are compelling, especially given that PEF witness Robinson acknowledged that the depreciation study did not address or analyze such information. We note that PEF's depreciation witness admitted that he had no specific knowledge with regard to any of the items about which the intervenors criticized. We find that if PEF had specific information supporting its life spans, it should have provided it in the depreciation study. Rule 25-6.0436, F.A.C., requires that a depreciation study include a justification for a company's proposed depreciation parameters for each study category. This justification includes such things as growth, company planning, technology, physical conditions, and trends.

Based on the foregoing, we agree with OPC and FIPUG that PEF's depreciation study is void of any supporting information regarding the life spans used in the depreciation study. Moreover, we find that the supporting information provided in response to discovery consisted of conclusory responses without any specific data or analysis to support the life spans. Further, recognizing that PEF itself acknowledged that the actual service life or life span of a generating unit is not actually known until it is retired, we agree with FIPUG that consideration of life spans used by other electric companies is in order. We find it compelling that Gulf lengthened the estimated life span for its combined cycle units in Florida to 34 years in 2007,[15] and that Gulf's 2009 Ten-Year Site Plan indicated an estimated 40-year life span for a new combined cycle unit.

On balance, we find a minimum life span of 35 years shall be used in this proceeding for PEF's combined cycle units. For the Hines Energy Complex and the new Bartow units for which PEF proposed life spans shorter than 35 years, we find that 35 years shall be used for determining depreciation parameters. PEF's proposed life span of 41 years for Tiger Bay appears reasonable for this proceeding. We recognize that FRF pointed out that based on the composition of combined cycle units, PEF should likely experience life spans of 40 years or more based on the ages of PEF's existing steam and combustion turbine units. For this reason, we find that PEF shall provide in its next depreciation study a detailed analysis demonstrating the expected life span of its combined cycle generating facilities including why they should not be expected to operate for 35 years or longer.

[15] 2005 Gulf Depreciation Study, p. 2.

Conclusion

Accordingly, we find that a 35-year life span shall be used in this proceeding to determine the appropriate depreciation parameters for the Hines Energy Complex Units 1-4 and the new Bartow unit. For Tiger Bay, we find that PEF's proposed 41-year life span is reasonable. Also, PEF shall provide with its next depreciation study a detailed analysis demonstrating the expected life span of its combined cycle generating facilities, including why the plants should not be expected to operate for 35 years or longer.

F. Depreciation Parameters for Production Units

PEF's depreciation rates were last fully reviewed in 1997 and the results of this review were memorialized in Order No. PSC-98-1723-FOF-EI, issued December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study by Florida Power Corporation (1997 FPC Depreciation Order). As part of its 2002 earnings settlement,[16] PEF's depreciation rates approved in 1997 continued unchanged. In the 2005 rate case settlement,[17] the depreciation rates contained in PEF's depreciation study filed in that proceeding were accepted with some modifications agreed to by the parties. The instant study therefore represents the first opportunity in 12 years for a complete and thorough review of PEF's recovery position by this Commission.

The scope of PEF's depreciation study included statistical analyses of Company historical data, discussions with Company management to identify prior and prospective factors that could impact service lives, and information from plant inspection tours. The FIPUG and OPC witnesses asserted that PEF did not provide the requisite specific substantiating information necessary to support and justify its proposals. PEF witness Robinson stated that while he had knowledge and general understanding of the production facilities, he could not identify specific factors affecting PEF's generating plants.

Rule 25-6.0436, F.A.C. (our depreciation study rule), sets forth depreciation study requirements. Subsection 6(f) of the rule requires that each study contain:

> An explanation and justification for each study category of depreciable plant defining the specific factors that justify the life and salvage components being proposed. Each explanation and justification shall include substantiating factors utilized by the utility in the design of depreciation rates for the specific category, e.g., company planning, growth, technology, physical conditions, and trends. The explanation and justification shall discuss any proposed transfers of reserve between categories or accounts intended to correct deficient or surplus reserve

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[16] Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket Nos. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor, p. 17. (2002 PEF Earnings Settlement)

[17] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc., pp. 3, 159-165. (PEF 2005 Rate Case Settlement Order).

> balances. It should also state any statistical or mathematical methods of analysis of calculation used in the design of the category rate.

The depreciation study rule also requires that depreciation studies be filed at least once every four years from the date of the previously filed study, unless otherwise required by this Commission. If a company wishes to have revised depreciation rates considered in a base rate revenue requirements proceeding, the rule requires that the study be submitted by the time of the filing of the Minimum Filing Requirements (MFRs). (Rule 25-6.0436(8), F.A.C.).

While PEF witness Robinson testified that the depreciation study was prepared in accordance with Rule 25-6.0436, F.A.C., we note that witness Robinson admitted that not all the documentation required by the depreciation study rule was included in the depreciation study. Although additional information was provided in response to discovery requests, witness Robinson acknowledged that it was not sufficient to comply with the depreciation study rule requirements. When PEF was asked to specifically identify what information was relied upon in the course of performing the depreciation study, what life analysis procedure was utilized, and any other information specifically relied upon in developing the resulting life parameters, PEF witness Robinson responded that "the process of service life and future net salvage estimation is interpretative as opposed to an arithmetic approach." We find that the information PEF provided to support the average service lives for PEF's generating units simply shows its proposed service lives with some conclusory statements, but no substantiating information. For the production accounts, PEF's depreciation study only provided the proposed parameters with generalized discussions. There is no discussion or explanation of the pressures facing PEF, how those pressures are impacting life and salvage parameters, or how PEF plans to address those pressures.

PEF's depreciation study did not discuss how or why witness Robinson selected the specific experience bands[18] that he used in his statistical actuarial analyses. While witness Robinson quoted from the National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices (NARUC depreciation manual) that "depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions," if he relied on anything besides the past, we find that information was not specifically identified in the depreciation study.

Section 4 of the PEF depreciation study provided the study analysis and results. For example, Account 311 contained plant statistics as of December 31, 2007, such as the investment, average age of the surviving investment, original gross additions, the oldest surviving vintage, historical retirements, and the average age of retirements. These statistics were not estimated out to PEF's proposed implementation date of January 1, 2010. Section 4 of the study also provided a narrative of plant considerations and future expectations. This included a general description of the generating plants, including when they were placed into service. The remaining discussion consisted of:

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[18] Experience bands refer to the range of years being studied upon which the observed life table is constructed. The observed life table represents the experienced or estimated survival characteristics of the property.

> The Crystal River Units 4 & 5 are in the process of undergoing major upgrading and the Bartow Units are scheduled for retirement during 2009. The increasing focus on air quality standards inclusive of carbon regulation will continue to place increasing burdens on the Company to maintain and/or continue to operate generating plants within i[t]s fossil fleet.

We note that this exact same narrative was provided for each of the steam production accounts. Similar non-specific narratives were provided for PEF's nuclear and other production accounts. Other than the results of the historical statistical analysis, this language was the only support offered for PEF's proposed life and salvage factors for the steam production plants and accounts. We find that these narratives did not constitute an adequate explanation and justification for any of the steam production accounts, and did not define or describe the specific factors that justified the life and salvage components being proposed. We cannot locate anything in PEF's study that meaningfully discussed the key factors presumably considered by PEF in its design of depreciation rates for a given category, such as company planning, anticipated growth, technology, physical conditions, and trends. The only thing the study contained was the results of the statistical analyses performed and the calculations yielding the category's rate. There was no indication how the interim retirement rate was selected or why. There was no information regarding how potential changes in air quality standards may impact the lives of the steam plants.

In a depreciation study review, depreciation rates should only be revised where warranted. With the passage of time, all other things remaining equal, the average remaining life will necessarily change due to the increased age of the plant. OPC witness Pous asserted that the sole support and basis for PEF's life and salvage proposals for production plant are only the numerical analyses presented and a statement that life and salvage determinations are not an arithmetic process but an interpretative process. Our staff requested that PEF identify the factors it evaluated that indicate a need to revise the estimated life and salvage values from the 2005 study, other than the results of the depreciation computer program analysis. PEF responded, "Mr. Robinson's depreciation study analysis approach is to view each study as a fresh start project." The response goes on to state that the study analysis is the reason for the proposed changes. We find that PEF provided no other basis, narrative, or explanations supporting its assumptions or determinations. Thus, we conclude that PEF failed to carry its burden of proof regarding its proposed depreciation rates for production plant. We agree with OPC witness Pous that PEF has provided only generalized statements with little support or documentation. We believe there should be an objective reason for changing life and salvage values other than that the computer program dictates the change. We further believe that company planning is an important element in developing appropriate life parameters for production plant, a discussion that was lacking in PEF's depreciation study and discovery responses, even though it was requested.

OPC witness Pous stated that the remaining life technique recognizes that depreciation is a forecast or estimation process. Both PEF witness Robinson and OPC witness Pous testified that depreciation involves subjectivity and judgment plays an important role. However, OPC witness Pous asserted that simply referring to judgment as the basis for a proposal without providing factual support, or as the basis for ignoring relevant facts, is inappropriate. We find that OPC's arguments are persuasive.

1. Life Spans

Production plant was studied using the life span method. The depreciation study narrative stated that a probable retirement date was determined after considering "management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current – as well as the overall – expected service life of the property being studied." When asked to identify the industry standards considered in determining the probable retirement dates, PEF responded, "company management completed a specific detailed review of its generating plants with the task of estimating terminal dates at which time the various operating plants would be retired and/or anticipated to be significantly upgraded/rebuild to enable the facilities to continue to provide future service." None of the referenced "detailed review" was documented or provided in the depreciation study or in PEF's discovery responses.

PEF's proposed retirement date for the Suwannee steam units is 2013. With an in-service date of 1953, this translates into a life span of 60 years. PEF's 2009 Ten-Year Site Plan encompassed planning for the retirement of this plant. Recognizing that OPC or any intervenor did not appear to object to the projections for the Suwannee plant, we find that a 60-year life span is appropriate to use in this proceeding.

For Anclote, we believe that the criticisms PEF waged against OPC's proposed life span can equally apply to PEF. OPC witness Pous stated that based on his review of PEF's depreciation study, he found that the study did not contain specific information with regards to 1) the condition of PEF's generating facilities with respect to their life spans, 2) PEF's expertise in operating or maintaining its generating units, 3) substantiation that PEF has unique load demands or how load demands impact the life spans, 4) updates, changes and reconfigurations made at each plant and how each affects the operating characteristics of the generating units with respect to life spans, 5) how renewable energy requirements may impact the life spans, and 6) the environmental risks PEF faces and how these risks may impact the life spans of the generating facilities. We find that these omissions are compelling, especially since PEF witness Robinson acknowledged that the depreciation study did not address or analyze such information. We note that PEF's depreciation witness admitted that he had no specific knowledge with regard to any of the aforementioned items for which the intervenors are criticized. If PEF had specific information supporting its life spans, it should have provided it in the depreciation study.

We note that PEF admitted that its proposed life spans did not reflect firm decisions. Further, although PEF witness Crisp provided the only support for PEF's life spans, we note that this was not filed as support for PEF's depreciation study. Even so, find the information presented by witness Crisp is not adequate in that it gave only conclusory comments.

We agree with OPC that PEF's depreciation study is void of any supporting information regarding the life spans used in the depreciation study. While we generally believe that the lives of production plant should be based on company-specific planning and information, in the instant case, that information is lacking. Further, recognizing that PEF itself acknowledged that the actual service life or life span of a generating unit is not actually known until it is retired, we agree with OPC that consideration of life spans used for other electric companies is reasonable.

In sum, we find PEF has not provided competent substantial evidence supporting its proposed life spans. We reiterate our belief that company-specific planning is a very important element in a depreciation study. In this respect, we find PEF's depreciation study falls short. For these reasons, we find that relying on the life span estimates of other companies, as OPC did, has merit. Accordingly, we find that a 50-year life span for the large steam or oil-fired plants shall be used to determine the appropriate life factors in this proceeding.

a. Nuclear Production

The narrative discussion in Section 4 of the depreciation study regarding plant considerations and future expectations for PEF's nuclear plant, Crystal River Unit 3, described the investment and the method used for life analysis. Given that PEF is seeking a license extension for Crystal River Unit 3, we are puzzled why issues relating to license extension were not considered sufficiently important to discuss in the depreciation study.

PEF developed its proposed life span assuming a 20-year license extension is approved by the Nuclear Regulatory Commission. PEF's life span was based on a retirement date of mid-2036. OPC witness Pous' proposed life span was based on an actual license termination date of December 2036. All things considered, we find that OPC witness Pous' life span is more reasonable, because it matches the end of the unit's extended operating licensed life.

b. Other Production

Other production includes combustion turbines and combined cycle plants. Given that no evidence was presented that challenged PEF's proposed life spans for its combustion turbines, we find that those be used in determining the depreciation life parameters in this proceeding. For the reasons previously discussed, as well as those discussed above regarding steam production life spans, we find that the use of a minimum life span of 35 years in determining the appropriate life parameters for PEF's combined cycle plants is appropriate in this proceeding.

2. Interim Retirement Rate

Under the life span study method, an interim retirement rate was developed to recognize investments expected to retire prior to the retirement date of the applicable property. We note that interim retirements represent the investments not expected to live the full life span of the generating plant. PEF witness Robinson used an actuarial survivor curve analysis[19] to develop his interim retirement rates. The witness' approach was based on an Iowa curve truncated at the retirement date. Witness Robinson stated that the specific Iowa curve he selected to represent future interim retirements was representative of historical retirements. If this is true, then we

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[19] Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. An actuarial analysis is a study of historical retirements that have taken place at various ages in relation to the property exposed to retirement.

infer that witness Robinson concluded that PEF's generating plants will experience the same level of interim retirements in the future as they did in the past.

On the other hand, OPC witness Pous used a constant interim retirement rate based on PEF's historical retirement data for each account. While PEF witness Robinson alleged that OPC witness Pous' calculation produced one single interim retirement rate for all production accounts, this is not correct. We note that contrary to PEF's contention, the OPC witness developed a constant interim retirement rate for each production account, not one rate for all accounts.

Regarding the use of actuarial analyses in determining interim retirement rates, OPC witness Pous asserted that actuarial analyses are not suitable for production plant investments and they overstate projected interim retirements. As an example, witness Pous referenced Account 312, Boiler Plant Equipment. Using PEF's proposed interim retirement approach, $394 million of investments would be expected to retire over the 20-year remaining life, or about $20 million annually. However, a review of the historical retirement activity for this account indicated total retirements of about $60 million over the past 32 years. Witness Pous concluded that, on an annual basis, PEF's approach results in projected interim retirement levels that would result in more than 10 times the average annual historical retirement levels. The OPC witness contended that no evidence demonstrated that Boiler Plant Equipment could reasonably be expected to incur future interim retirements of this magnitude. We agree and note that PEF did not refute OPC's allegation that actuarial analyses can overstate interim retirements.

Both PEF witness Robinson and OPC witness Pous cited to the California Public Utilities Commission PUC-U-4[20] publication to support their selected approach to calculate the interim retirement rates used in determining the average remaining lives for each account within each plant. The witnesses also acknowledged that both approaches are recognized approaches in the NARUC depreciation manual for determining an interim retirement rate.

An actuarial analysis studies how property has lived historically. Knowing what happened yesterday may help one better understand what is happening today and what may happen tomorrow. However, PEF provided no substantive information regarding anticipated future retirement characteristics. Moreover, if PEF witness Robinson's analysis is representative of historical retirements, then presumably so is that of OPC witness Pous, since his method is also based on historical retirements.

PEF was requested to identify and provide documents supporting its selected life and Iowa curve combinations for each of the production plant accounts. In some responses, PEF stated that the estimation of life parameters is "interpretative," which includes a consideration of historical data as well as anticipated future changes. In another response, PEF stated that "[a]ll Iowa curves that indicate a good fit with the observed data are the product of our proprietary software model and would have to be rerun to provide all other curve fits besides the selected curves provided in this study." In another response, PEF stated that the computer software was

[20] California Public Utilities Commission, Determination of Straight-Line Remaining Life Depreciation Accruals Standard Practice U-4.

proprietary and provided statistical output. We find that these responses do not support the reasonableness of PEF's interim retirement rate. Absent sufficient evidence as gleaned from these responses, we are unable to verify that witness Robinson's interim retirement rates are appropriate.

For the above reasons, we believe that PEF has not provided substantial, competent evidence supporting the reasonableness of its interim retirement rates. Thus, we are unable to approve the use of them in this proceeding. However, we recognize that PEF acknowledged that OPC's interim retirement approach was an acceptable method, although not what it recommended. Because an interim retirement rate is needed to determine the average remaining life for each production account within each production account, we find that the interim retirement rates proposed by OPC witness Pous are appropriate to use in this proceeding.

3. Lives

The interim retirement rate is applied to the life span to determine the resulting average service life for each account within each plant. No party objected to this methodology. We observe that both PEF and OPC recognize that depreciation involves estimates. For this reason, we believe there is little reason to be as precise as a hundredth of a year. Our approved lives reflect the rounding of lives over 20 years to the nearest whole year and lives less than 20 years to the tenth of the year.

Our approved remaining lives reflect applying the applicable interim retirement rates truncated at the retirement date as determined by the life spans discussed above. We agree with PEF that using the life span study method, no investment can be considered surviving past the retirement date of the production unit.

4. Interim Net Salvage

PEF's depreciation study stated that the level of interim net salvage was based on an account level analysis of historical data. The result was then applied to the level of interim retirements anticipated to occur over the life span of the applicable plant. However, like OPC, we were unable to duplicate PEF's historical results.

Considering PEF's reliance on historical data, discovery responses stating that PEF's approach was interpretive rather than mathematical is puzzling. While PEF witness Robinson stated that management input regarding current and potential changes were considered, we are perplexed that PEF did not provide information regarding its net salvage analysis, even when requested. For this reason, we agree with OPC that PEF did not adequately explain how the initial net salvage result before adjusting for interim retirements was determined.

Under a reserve-sensitive depreciation methodology like remaining life, we believe it is requisite that the data match the implementation date of revised depreciation rates. Estimates are permitted under the depreciation study rule, and PEF used its forecasted 2008 and 2009 data in its remaining life calculations. However, as noted by OPC, PEF's salvage data was provided through December 31, 2007. PEF contended that because its life analyses did not include 2008 and 2009 forecasted addition and retirement data, then its salvage analyses did not necessitate updated data. As noted by OPC, to the extent there were significant additions and retirements forecasted and these were not considered in the analyses, PEF's proposed net salvage results could be overstated. We agree with OPC and believe that the same can be said with regard to PEF's life analyses. Whether estimating life or salvage characteristics, the data being studied, estimated if necessary, should match the implementation date of proposed depreciation rates. We find this is another reason to question PEF's proposals.

The approved net salvage proposals for each account reflect PEF's historical salvage analysis, adjusted for interim retirements using the applicable constant retirement rates discussed previously. As with the determination of lives, we truncated the constant interim retirement curve at the date of retirement. As the OPC witness proposed, where the historical data yielded a positive net salvage, we conservatively approve a zero interim net salvage. With respect to OPC's additional proposal that PEF be directed to perform a detailed, thorough, and documented depreciation study for its next regularly scheduled filing, we believe the substance of this proposal is set forth in the depreciation study rule and no other direction is necessary.

Conclusion

The approved depreciation parameters and resulting depreciation rates for production plant are shown on Table 1. The reserve positions shown incorporate the effects of the approved reserve allocations addressed later in this order.

Table 1: Production Plant Life and Salvage Components and Depreciation Rates

	CURRENT APPROVED*			COMMISSION APPROVED				
ACCOUNT	Average Remaining Life	Net Salvage	Remaining Life Rate	Average Remaining	Net Salvage	Allocated Reserve		Remaining Life Rate
STEAM PRODUCTION								
Anclote Steam								
311 Structures and Improvements	15.0	(2.3)	3.24	16.7	(3.0)	71.51		1.9
312 Boiler Plant Equipment	14.5	(12.5)	3.34	16.5	(4.0)	68.16	**	2.2
314 Turbogenerator Units	14.5	(3.3)	2.31	16.1	(4.0)	58.92	**	2.8
315 Accessory Electric Equipment	14.5	(3.0)	1.99	16.7	(1.0)	74.68		1.6
316 Misc. Power Plant Equipment	13.4	(5.9)	2.21	15.4	(3.0)	77.64		1.6
Crystal River 1 & 2 Steam								
311 Structures and Improvements	14.2	(2.3)	2.57	10.5	(3.0)	80.22		2.2
312 Boiler Plant Equipment	13.7	(12.5)	4.03	10.4	(4.0)	65.52	**	3.7
314 Turbogenerator Units	13.9	(3.3)	3.06	10.2	(1.0)	75.11	**	2.5
315 Accessory Electric Equipment	13.8	(3.0)	2.88	10.5	(3.0)	76.12		2.6
316 Misc. Power Plant Equipment	12.7	(5.9)	3.19	9.9	(3.0)	82.66		2.1
Crystal River 4 & 5 Steam								
311 Structures and Improvements	17.0	(2.3)	3.39	33.0	(3.0)	53.96	**	1.5
312 Boiler Plant Equipment	16.1	(12.5)	2.83	33.0	(4.0)	22.49	**	2.5
314 Turbogenerator Units	16.2	(3.3)	2.14	31.0	(1.0)	70.82	**	1.0
315 Accessory Electric Equipment	16.4	(3.0)	2.78	33.0	(3.0)	71.65	**	1.0
316 Misc. Power Plant Equipment	15.0	(5.9)	3.27	28.0	(4.0)	44.78	**	2.1
Suwannee River Steam								
311 Structures and Improvements	11.9	(2.3)	1.45	3.5	(3.0)	94.95	**	2.3
312 Boiler Plant Equipment	11.6	(12.5)	2.96	3.5	(4.0)	93.15	**	3.1
314 Turbogenerator Units	11.7	(3.3)	1.13	3.5	(4.0)	93.85	**	2.9
315 Accessory Electric Equipment	11.8	(3.0)	0.98	3.5	(1.0)	91.90	**	2.6
316 Misc. Power Plant Equipment	10.9	(5.9)	1.71	3.4	(3.0)	93.01		2.9
Bartow/Ancl. Pipeline								
311 Structures and Improvements	14.8	(2.3)	3.07	16.4	(3.0)	73.18		1.8
312 Boiler Plant Equipment	14.8	(12.5)	4.10	16.4	(4.0)	62.05		2.6
315 Accessory Electric Equipment	15.1	(3.0)	2.78	16.4	(4.0)	81.77		1.4
316 Misc. Power Plant Equipment	13.6	(5.9)	5.20	15.1	(3.0)	52.27		3.4

* Order No. PSC-05-0945-S-EI, Docket No. 050078-EI.
** Reserve after Commission approved reallocations.

G. <u>Depreciation Parameters for Transmission, Distribution, and General Plant Accounts</u>

PEF depreciation witness Robinson averred that the process of service life and future net salvage estimation is interpretative as opposed to an arithmetic approach. He asserted that while analysis of historical information is used to determine what has occurred in the past, there is no assurance that the future will mirror past circumstances. He asserted that a depreciation professional uses personal knowledge and experience of property classes, but also considers other factors. These factors include the account's content, detailed discussions with PEF, whether the composition of the account has changed over time, changes in the growth of the account, the ages of the property under analysis, and what impact future retirements are expected to have on plant lives.

Witness Robinson included retirements, cost of removal, and salvage data that occurred as result of the 2004-2005 hurricanes in his historical life analysis. Witness Robinson did not consider hurricane-impacted retirements to be abnormal or atypical data. Witness Robinson included hurricanes because they occur with sufficient frequency such that it is highly probable that they will regularly impact property over its typical useful life. When asked in his deposition for an example of an atypical event that he would exclude from analysis, witness Robinson responded that a 9/11-type attack would be excluded.

Witness Robinson excluded gross salvage related to "return to stores" (inventory) because these transactions "are not true gross salvage" because "they are simply an accounting entry related to limited retirements of the Company's total plant in service and are applicable to reuse of material within the Company's operating system." Witness Robinson averred that the inclusion of these items in future net salvage estimates is inappropriate because the overwhelming majority of retired property in service will not experience such treatment.

PEF witness Robinson based the average service lives for certain transmission and distribution accounts on the judgment and consideration of industry data because of limited or no available PEF data. The industry data used by witness Robinson was from an AGA/EEI (American Gas Association/Edison Electric Institute) depreciation survey. Although witness Robinson's use of industry data will be discussed in the account-specific portion of this order, we note that for each account, witness Robinson's proposed average service life is longer than industry average life contained in the survey.

Witness Robinson characterized his approach to a depreciation study as a "fresh start;" that is, he does not view the results of the prior study until after the current study is completed. Witness Robinson asserted that unless there is some compelling reason to maintain the existing depreciation parameters (which is not typically the circumstance) the newly estimated parameters become the basis of the proposed depreciation rates.

OPC witness Pous provided testimony as well as specific proposals for some of the transmission, distribution, and general plant accounts. OPC argued that PEF's depreciation study is in violation of Rule 25-6.0436, F.A.C., because PEF did not provide the mandatory, required specific substantiating information. OPC witness Pous asserted that the basis for PEF's study is not in the study, workpapers, and responses to data requests where witness Pous requested the basis for PEF's proposals. OPC argued that PEF witness Robinson acknowledged that the company did not file the documentation required by the rule. OPC contended that because of this failure alone, we should accept the recommendations of OPC witness Pous relating to all depreciation issues. Witness Pous noted that PEF described the depreciation study process as one that is "interpretative," not "arithmetic;" however, witness Pous asserted, what was presented by PEF was "numerical" and without any other basis, narrative, explanations. Witness Pous further contended that in the 2005 PEF depreciation study, witness Robinson provided a narrative, unlike the 2009 depreciation study.

Witness Pous disagreed with PEF witness Robinson's view that hurricane data should not be removed from the study. He asserted that, to base a negative net salvage proposal on unusual activity which reflects higher costs of removal than would be anticipated during more normal operation should not be relied upon for establishing long term net salvage expectations.

PEF argued that, based on the evidence, sound regulatory policy, and well recognized depreciation principles, the intervenor witnesses' recommendations must be rejected. PEF witness Robinson asserted that it was his testimony that a depreciation expert can turn to the study, look at the range of data and rather quickly visualize and interpret what we estimated in the way of net salvage and to either agree or disagree with that estimate. PEF characterized OPC's study as "results-driven;" for example, OPC's recommendations to increase average service lives for two of the largest accounts have a much larger impact on the Company's level of depreciation expense.

In his response to a question about the information available in the study for a particular account, witness Robinson testified that

> It's there, black and white. It's in data. One can see it. I would anticipate that anyone that is investigating this study would be knowledgeable in depreciation analysis, and if they look and see that I've estimated zero percent, to me – maybe I'm reading things into it, but to me it's rather obvious that, well, you've experienced positive salvage, it's now turned negative, so certainly zero would be a reasonable, gradual approach in the middle of that estimate.

Witness Robinson further testified that those knowledgeable about depreciation might not "concur" with his answer, but that they could either accept or reject his estimate based upon the range of data that is there.

Witness Robinson compared his proposed net salvage factors for selected plant accounts with those for Florida investor-owned utilities. His comparison included proposed net salvage percentages for FPL and Gulf, with Commission-approved net salvage for Tampa Electric Company (TECO). Witness Robinson asserted this comparison shows that his proposals are reasonably comparable, if not lower, than the other operating entities. While witness Robinson asserted that net salvage factors should be based on the merits of the information within each operating company, the comparison demonstrates that his recommendations are not excessively negative and in fact are conservative.

PEF argued that the comparison of net salvage factors demonstrates that OPC's proposed net salvage factors for PEF and FPL are driven by a results-oriented approach. According to witness Robinson, OPC witness Pous recommended a considerably lower level of negative net salvage for PEF's property than he recommended for FPL's property.

The approved depreciation parameters include the remaining life, net salvage percent, and reserve percent, all of which are used to calculate the remaining life depreciation rate. Parties also provided a proposal for a curve and average service life (often referred to as ASL), both of which are used in the calculation of the remaining life. Curves are generally denoted by a letter that describes when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the average life, while an R curve implies that retirements tend to occur after the average life of plant. The average service life denotes the average number of years that the plant within a particular account is expected to live. While the ASL may be based, at least in part, on historical data, it is prospective in its outlook and implementation. The remaining life is the average number of years left for plant in the account.[21] The net salvage, also based on historical data and prospective in outlook, is the sum of the gross salvage and cost of removal. The reserve percent is calculated by dividing the book reserve by the original cost of plant. We note that the reserve is discussed later in the order.

OPC witness Pous provided testimony as well as proposals for some of the transmission, distribution, and general plant accounts. PEF's and OPC's arguments can be divided into those that apply to all accounts and those that are account-specific. This order will discuss the parties' arguments that apply to all accounts first and then follow with an account-by-account analysis which includes arguments specific to each account.

Not unexpectedly, there are many points of disagreement between PEF and OPC. Two of the most significant include the required and appropriate level of supporting documentation, and whether the impacts of hurricanes should be included in, or excluded from, the data analyzed.

A key element missing from PEF's proposals is a narrative that explains the reasons for proposed changes. PEF's view is that any person knowledgeable in depreciation can review the study data and understand why PEF is proposing what it is. As a corollary to that, PEF believes that a "fresh start" is appropriate and that it is not necessary to explain large differences between current and proposed parameters because the data tells the story.

Narratives are the simplest way to describe the underlying reason why, for example, a change in curve from L2 to R3 is being proposed. We believe that the level of explanation or narrative preferred may differ depending on the difference between the current and proposed parameters. However, the burden is on the Company to provide a depreciation study that adequately explains the basis for its proposals. While a review of the data analyzed provides a depreciation analyst with a great deal of information, data analysis alone does not tell the whole story. For example, most depreciation analysts familiar with recent hurricane activity in Florida will suspect that unusually high retirements and cost of removal in or adjoining major hurricane years (such as 2004 and 2005) are the results of the hurricanes. But there may be other factors at play, and unless the Company explains what those factors are, we are unable to develop a complete understanding of what is occurring in each account.

We are puzzled by PEF's "fresh start" approach. We agree that the data should be studied independently; however, a key part of any study is understanding what the differences are between what is currently in use and what is proposed. The reason may be as simple as four

[21] We observe that both PEF and OPC recognize that depreciation involves estimates. Thus, as stated previously in this order, there is little reason to be as precise as a hundredth of a year for remaining lives. The approved lives reflect the rounding of lives over 20 years to the nearest whole year and lives less than 20 years to the tenth of year.

more years of data yields better results, but it may be more complex than that. Whatever the reason, the Company is in the best position to know. The Company should explain significant differences between its current and proposed parameters in its study.

With regard to hurricane data, PEF clearly includes it as normal data. We are not advocating that PEF exclude the data for years with significant hurricane impacts, but we agree with OPC that including hurricane data can skew the results. Hurricanes are a fact of life in Florida; however, predicting their frequency and severity is something not even the experts can do. We believe that PEF's approach can lead to overestimating the impact of hurricanes, thus unnecessarily increasing depreciation expense. For the purpose of this proceeding and given recent hurricane activity, it is reasonable and appropriate to discount or eliminate hurricane activity to the extent the record permits.

While PEF's comparison of some net salvage percentages with other Florida utilities is interesting, it is not possible to accurately compare PEF's selected proposals with the other Florida utilities because there is no information in this record, for example, on whether FPL, Gulf, and TECO include the impacts of hurricanes in their net salvage analysis, as PEF does. We agree with PEF that net salvage should be based on the merits of the information within each operating company.

PEF argued that OPC's proposals are "results driven." We are not privy to how OPC determined the accounts for which it made proposals. We believe that the appropriate analysis is done on an account-by-account basis, analyzing the basis of the proposals from both PEF and OPC rather than the results.

Our staff and OPC conducted extensive discovery on PEF's depreciation study. PEF also provided additional information in its rebuttal of OPC's proposals for certain accounts. We find that the record contains sufficient information to analyze and critique PEF's depreciation study.

Account-Specific Analysis: Transmission Plant

1. <u>Account 350.10 – Land Rights</u>

PEF proposed no change in its curve (R3), its average service life (75), or its net salvage (0 percent). PEF witness Robinson considered and based his proposal on industry data for this account. Industry data, obtained from the AGA/EEI depreciation survey, show an industry average life of 66 years for this account. None of the intervenors offered a proposal for this account different from PEF's proposal.

2. <u>Account 352.00 – Structures and Improvements</u>

PEF proposed no change in its curve of R2.5, or its net salvage of (15) percent. PEF proposed an increase in the average service life from 60 to 75 years. None of the intervenors offered a proposal for this account that differs from PEF's proposal.

When asked in discovery for the "specific factors" that resulted in the change of ASL, witness Robinson did not provide any information specific to this account; instead, he provided a general explanation.

3. Account 353.10 – Station Equipment

PEF proposed a modest change in the curve from R1 to R0.5, an increase in the average service life from 52 to 53 years, and no change in the net salvage of 0 percent. OPC proposed an increase in net salvage from 0 to 5 percent.

OPC argued in support of its net salvage proposal that PEF is unable to identify the "mix" of investment and retirements in this account which means that it has not investigated the investment mix and retirement mix to see if the historical data represents current expectations. OPC also argued that transformers have increased in scrap value recently. Witness Pous also asserted that, witness Robinson has over-reacted to recent negative net salvage occurrences that correspond to hurricane time frames.

PEF witness Robinson responded that a portion of the large net salvage in 2007 was related to over 50 transformers that had been long out of service. According to witness Robinson, excluding the effect of these old transformers would have resulted in (22.2) net salvage. Witness Robinson opined that any increase in scrap value is far from certain. PEF witness Robinson's rebuttal is persuasive; therefore, we find that keeping the net salvage of 0 percent is appropriate.

4. Account 353.20 – Station Equipment – Station Control

PEF proposed a significant change in its curve, from L2 to R3, but no change in its average service life of 17 years, and its 0 percent net salvage. None of the intervenors offered a proposal for this account different from PEF's proposal.

As described earlier, an L curve implies that retirements tend to occur prior the average life, while an R curve implies that retirements tend to occur after the average life of plant. When asked in discovery for the specific factors that resulted in the need to change the curve, other than the results of the depreciation program's computer analysis, PEF witness Robinson responded with a general response that described his "fresh start" approach. He stated that the results of the previous study are not compared to the current study until the current study has been completed. He asserted that, unless there is some compelling reason to maintain the existing depreciation parameters (which is not typically the circumstance) the newly estimated parameters become the basis of the proposed depreciation rates being set forth in the current depreciation study. Witness Robinson did not provide specific reasons that could account for the change from an L curve to an R curve. A curve change from L2 to R3 is too great a change to occur without any information about why the average plant appears to be retiring at a later age. Witness Robinson's support for his change in curve was inadequate. Therefore, a more reasonable approach is to retain the L2 curve.

5. Account 354.00 – Towers & Fixtures

PEF proposed a modest change in its curve, from R4 to R3, an increase in average service life from 58 to 65 years, and a decrease in net salvage, from (25) percent to (30) percent. PEF witness Robinson considered and based his proposal on the AGA/EEI industry data for this account, which show an industry average life of 50 years. None of the intervenors offered a proposal for this account different from PEF's proposal.

PEF's proposed original cost balance for this account is $66.5 million dollars as of December 31, 2009. Since 1999, there have been retirements in only three years: 2002 ($165,088), 2005 ($2.6 million), and 2007 ($5,484). We believe that these limited retirements over the past ten years lend credence to PEF's proposed lengthening of life to 65 years. Although the cost of removal has been negative since 2003, the limited amount of data is inadequate to support a decrease in net salvage from (25) percent to (30) percent.

6. Account 355.00 – Poles and Fixtures

PEF proposed a modest change in the curve from R1.5 to R2, a decrease in the average service life from 40 to 38 years, and a decrease in net salvage from (25) to (50) percent. OPC proposed that the net salvage remain at (25) percent.

OPC argued that its net salvage recommendation does not react to the unexplained 5 to 10 fold increase in cost of removal seen by PEF during the last several years, coincident with hurricane impacts. OPC witness Pous asserted that gross salvage has occurred in only one of the last four years, which contrasts significantly with PEF's historical gross salvage of 36 percent.

PEF witness Robinson did not address the impact of hurricanes; however, he did point to some modest level of third party damages. Witness Robinson also speculated that a sizeable portion of the recorded gross salvage is likely property returned to stores, and thus not real salvage at all. We find OPC's argument in favor of retaining the current net salvage is persuasive and provides for a moderate result.

7. Account 356.00 – Overhead Conductors and Devices

PEF proposed a modest change in curve from R2 to R1.5, an increase in average service life from 48 to 55 years, and no change in the (30) percent net salvage. OPC proposed an increase in salvage from (30) percent to (10) percent.

OPC argued that its proposed net salvage of (10) percent recognizes that prior to the impact of the recent hurricanes the Company had almost exclusively experienced positive net salvage for this account. OPC also argued that PEF appears to be overreacting to the excessive level of negative net salvage incurred in association with various projects that are heavily weighted to hurricane activity.

PEF did not respond to OPC's argument concerning hurricane impacts. PEF witness Robinson did not provide an explanation of considerable levels of negative net salvage; rather, he discussed his belief that historical gross salvage will simply not occur at the end of the property's life. Witness Robinson noted that there will be "some level" of scrap value but it will be limited due to primarily aluminum conductors.

We find that OPC's observation that hurricane impacts likely account for net salvage appearing too negative is persuasive; however, we are concerned that OPC's recommended change from (30) to (10) percent net salvage might be drastic. The record supports a compromise between the two positions; thus, we find that (20) percent is appropriate.

8. Account 357.00 – Underground Conduit

PEF proposed a modest change in its curve from R2.5 to R3, no change in its average service life of 55 years, and no change in its net salvage of 0 percent. This is one of the accounts for which PEF witness Robinson used industry data. The industry average life for this account is 51 years, less than PEF's proposed 55 years. None of the intervenors offered a proposal for this account different from PEF's proposal.

9. Account 358.00 – Underground Conductors and Devices

PEF proposed a modest curve change from R2.5 to R3, a decrease in the average service life from 55 to 50 years, and no change in the net salvage of (3) percent. OPC proposed an increase in net salvage from (3) percent to 0 percent.

OPC witness Pous asserted that, absent any narrative explanation in PEF's 2009 depreciation study, he looked to PEF's 2005 depreciation study for insight. According to witness Pous, the 2005 depreciation study estimated the net salvage at (3) percent because of the limited size of the amount of the property. According to witness Pous, there have been four retirements in 31 years and the overall net salvage is (0.27) percent. Witness Pous contended that a net salvage of zero is the only appropriate net salvage based on the information available.

PEF witness Robinson responded that a modest level of future negative net salvage will be required to disconnect the facilities. This is one of the accounts for which PEF used industry data for the average service life, which shows an average age of 39 years.

We are not persuaded by PEF's arguments. We agree with OPC witness Pous a net salvage of 0 percent is appropriate in light of the extremely limited historical data and the long life of this account.

10. Account 359.00 – Roads and Trails

PEF proposed a modest change in the curve, from R2.5 to R3, a decrease in average service life from 90 to 75 years, and no change in net salvage (0 percent). None of the intervenors offered a proposal for this account different from PEF's proposal.

PEF explained the decrease in life in general terms; however, it did not offer any specific reasons for the proposed decrease in life. This account is one of the accounts for which witness Robinson relied on his industry survey data. The industry average life for this account is 58 years. We find that the evidence to change the ASL is inadequate and the magnitude of PEF's proposed change is too large; therefore, the ASL shall remain at 90 years.

Account-Specific Analysis: Distribution Plant

1. Account 360.10 -- Land Rights

PEF proposed no change in its curve (R3), its average service life (75), or its net salvage (0 percent). PEF relies on industry data for use with this account. The average life for PEF's industry data is 57 years. None of the intervenors offered a proposal for this account different from PEF's proposal.

2. Account 361.00 – Structures and Improvements

PEF proposed a modest change in its curve, from R2.5 to R2, an increase in the average service life from 55 to 75 years, and a decrease in the net salvage, from (5) percent to (10) percent. None of the intervenors offered a proposal for this account different from PEF's proposal.

Witness Robinson provided no specific explanation for the change in net salvage. However, in a discovery response, he stated that, the current estimate of future net salvage is based upon a conservative approach in that current estimates are routinely focused on more recent experience with a gradualism towards the longer term future net salvage forecast. We find that PEF's proposal appears to be reasonable.

3. Account 362.00 – Station Equipment

PEF proposed a modest change in curve from R1 to R0.5, an increase in the average service life from 45 to 60 years, and no change in the net salvage of (15) percent. OPC proposed an increase in the net salvage from (15) to 0 percent.

OPC's primary arguments for increasing net salvage included removing the impact of recent hurricanes and an expected increase in scrap metal prices. PEF witness Robinson asserted that OPC witness Pous ignored the historical data provided to witness Pous at his request. PEF also argued that increases in scrap prices are far from certain.

While we find OPC's hurricane impact argument to be persuasive, we are concerned that a change in the net salvage from (15) to 0 percent is too great an increase. We find that net salvage shall be increased; however, the increase should be smaller. We find that a change from (15) to (10) percent is a moderate change that also recognizes OPC's hurricane impact argument.

4. Account 364.00 – Poles, Towers, and Fixtures

PEF proposed a significant change in curve from L4 to R4, an increase in average service life from 28 to 29 years, and a decrease in net salvage from (35) percent to (50) percent. OPC proposed an increase in average service life from 28 to 35 years, an R3 curve, and no increase to the (35) percent net salvage.

This is one of two accounts where OPC proposed a change in average service life (the other is Account 368.00, Line Transformers). OPC witness Pous asserted that PEF's proposed average service life is significantly shorter than any ASL Mr. Robinson has presented for investment in this account during the past 10 years. This fact alone, OPC argued, should have caused Mr. Robinson to further investigate or explain in detail why his proposed life is appropriate. OPC also pointed to significantly higher retirements for a three-year period. OPC witness Pous averred that this period of higher retirements, unexplained by PEF, can have an impact on the shape of the survivor curve, indicating a longer ASL. OPC argued that its 35-year ASL proposal is a conservative estimate for this account.

PEF witness Robinson asserted that OPC witness Pous reached his proposal by eliminating retirements that did not assist his objective and by using unsupported statements and conclusions. Yet, the retirements are substantial enough that we believe they should have been explained by PEF witness Robinson. Witness Robinson, however, did not offer any reasons for the retirements referred to by OPC.

PEF witness Robinson averred that he believes it is inappropriate to depend on studies for other companies when PEF-specific data is available. Witness Robinson summed up his rebuttal by stating that "Mr. Pous' estimate is simply a results oriented estimate from other operating company's service life information."

We believe that both PEF and OPC made good arguments; however, we are uncomfortable with the lack of explanation for the retirements in the three-year period. At the same time, we are uncomfortable with basing a decision on what PEF witness Robinson has presented in other cases. We believe the most reasonable approach is a compromise. Therefore, we find that an average service life of 32 years is appropriate.

PEF proposed a change in curve from L4 to R4, while OPC proposed an R3 curve. We note that when the average service life is changed to 32 years, the difference in remaining lives between the L4 and R4 is one tenth of a year. With a modest difference between the R3 and R4 curves, we believe an R4 curve is reasonable.

PEF and OPC disagreed as to the appropriate net salvage. PEF proposed a decrease in net salvage from (35) to (50), percent while OPC proposed that net salvage remain at (35) percent. According to OPC witness Pous, PEF's proposal relies on data that the Company admits occurred under catastrophic circumstances. OPC argued that its proposal of (35) percent is very conservative while providing additional time to determine how net salvage levels settle once the impacts of catastrophic circumstances associated with hurricane activity subside.

PEF argued in response that OPC's proposal is based heavily on historical data as opposed to consideration of future expectancies. PEF witness Robinson asserted that the cost of removal is likely to return to higher levels, fueled in part by labor costs and the fact that retirements and related cost of removal routinely occurs randomly in PEF's service territory, thus necessitating extensive travel time. Witness Robinson considered his proposal of (50) percent to be conservative.

Since PEF witness Robinson effectively built the effects of the 2004 and 2005 hurricanes into his analysis, we are concerned that his proposal understates net salvage. We find that the appropriate approach is to retain the current net salvage of (35) percent.

5. Account 365.00 – Overhead Conductors and Devices

PEF proposed a modest change in curve from R2 to R0.5, an increase in the average service life from 33 to 36 years, and a decrease in net salvage from (15) percent to (45) percent. OPC proposed a decrease in net salvage from (15) to (20) percent.

OPC witness Pous asserted his proposal places less weight on more recent data for two reasons. The first reason is that PEF admitted it did not report gross salvage for 2003 – 2006. The second reason is that PEF stated that retirements in 2004 and 2005 include equipment removed due to hurricane damage. Hurricane damage accounted for approximately 67 percent of retirements in 2004 and 64 percent in 2005. The 2004 and 2005 hurricanes have also caused the cost of removal to fluctuate because of timing differences.

PEF explained that the reason for no gross salvage was because of a true-up of the salvage for return to stores inventory that was processed in 2007. According to PEF, this account's property units are normally scrapped.

OPC witness Pous averred that PEF's net salvage proposal appears to be in reaction to hurricane related activity. We agree and find that net salvage of (20) is more reasonable.

6. Account 366.00 – Underground Conduit

PEF proposed a modest change in curve from R3 to R2.5, an increase in average service life from 55 to 67 years, and a decrease in net salvage from 0 to (10) percent. OPC proposed that the net salvage remain at 0 percent.

OPC argued that if the plant is abandoned there should be minimal negative net salvage and that if the plant is removed, there should be some gross salvage. OPC also noted the excessive level of cost of removal the Company experienced during the recent hurricanes. According to OPC witness Pous, PEF proposed 0 percent net salvage in its last (2005) depreciation study.

PEF argued that OPC's proposal is entirely based upon the statement that the property will be abandoned in place irrespective of the fact that the Company has experienced negative net salvage. Witness Robinson asserted that the very modest (10) percent net salvage is reflective of the fact that "much of the property may be abandoned in place.

We believe that both parties make good points in their arguments. In an effort to at least partially remove the hurricane impact and to account for cost of removal for abandoned plant, and finally, in an effort to change the net salvage in a more gradual manner, we find that a compromise, a net salvage of (5) percent, is appropriate.

7. Account 367.00 – Underground Conductors and Devices

PEF proposed a modest change in curve from R3 to R2, an increase in average service life from 34 to 35 years, and a decrease in net salvage from (5) percent to (10) percent. OPC proposed no change in net salvage, leaving it at (5) percent.

When asked in discovery why PEF is proposing to change the net salvage from (5) to (10) percent, witness Robinson provided the same answer that he provided for other accounts, which is the "fresh start." PEF's response stated that the newly estimated parameters are used unless there is compelling evidence not to use them.

OPC argued that if the excessive levels of negative net salvage associated with calendar years 2004 and 2005 were excluded, PEF's net salvage would be positive. OPC witness Pous also stated that PEF admits to retiring investment in place. Witness Pous asserted that when PEF actually retires and removes conductors, there should be gross salvage associated with the retirements. According to witness Pous, a net salvage of (5) percent may also be excessively negative.

PEF witness Robinson did not address hurricane impacts. While he agreed that gross salvage is possible with third party damage, he asserted that it is extremely unlikely that levels of gross salvage anywhere near the levels recorded in the past will be applicable. He also asserted that cost of removal actually forecasts to in excess of 130 percent. We find that OPC's proposal to retain (5) percent net salvage is a reasonable approach in the face of significant hurricane impacts in recent data.

8. Account 368.00 – Line Transformers

PEF proposed a modest change in curve from R2.5 to R2, an increase in average service life from 26 to 27 years, and a decrease in net salvage from (5) to (15) percent. OPC proposed an increase in the ASL from 26 to 33 years, an S0.5 curve, and no change in the net salvage of (5) percent.

OPC's arguments for an increased life for this account are similar to the arguments for an increased life in Account 364.00, Poles, Towers, and Fixtures. PEF witness Robinson's rebuttal is also similar to his rebuttal for Account 364.00. However, for this account, OPC proposed a different mode curve, an S0.5. A compromise is the most reasonable approach for the ASL; however, for the curve, we believe that PEF's proposal is reasonable. Therefore, an R2 curve with a 31 year ASL is a reasonable compromise.

For net salvage, PEF proposed a change from (5) to (15), percent while OPC proposed that the net salvage remain at (10) percent. The OPC witness asserted that hurricane-related retirements need to be taken into account. Witness Pous asserted that during 2005 and 2006, PEF retired a significantly higher percentage of equipment which is opposite the actual investment mix. OPC witness Pous characterized his proposal as conservative. PEF witness Robinson countered that there is a recent decline in gross salvage, while cost of removal levels have been increasing in the last several years. We find that both parties have made persuasive arguments; therefore, we find that a compromise of (10) percent is appropriate.

9. Account 369.10 – Services – Overhead

PEF proposed no change in the R3 curve, a decrease in average service life from 36 to 34 years, and no change in the net salvage of (50) percent. OPC proposed to increase the net salvage from (50) to (40) percent.

OPC argued that PEF did not recognize that the most recent data, including the effects of hurricanes, result in a positive net salvage. Since 2001, there have been retirements only in 2004, resulting in a net salvage of 2.67 percent. According to OPC witness Pous, reliance on recent data would serve to reduce the negative net salvage; however, he based his recommendation on the "concept of gradualism . . . only recommending a change to a negative 40% net salvage for this account."

PEF witness Robinson asserted that OPC witness Pous' assertion that recent data yields a positive level of net salvage is incorrect and unsupported. PEF witness Robinson further averred that OPC witness Pous was wrong when he asserted that this account routinely generates positive salvage because of the labor intensive removal and limited scrap value. Witness Robinson asserted that although there may be gross salvage in the future, nothing near the overall recorded levels of gross salvage will be experienced. We find OPC's argument is persuasive; it is a moderate change, based on available data.

10. Account 369.20 – Services – Underground

PEF proposed a relatively modest change in curve from R2.5 to R0.5, an increase in average service life from 38 to 43 years, and a decrease in net salvage from 0 to (15) percent. OPC proposed that the net salvage remain at 0 percent.

OPC argued that the net salvage should be increased because PEF's proposal appears to react to a major cost of removal reported during 2005 corresponding to hurricane related activity. Witness Pous asserted that witness Robinson's failure to compensate in any manner for the unusual storm related activity during the last several years is incorrect and unacceptable. According to witness Pous, if PEF had eliminated the retirements and the corresponding negative net salvage from 2005, overall net salvage for the last 10 years would have been between zero and (4) percent.

PEF witness Robinson disagreed that hurricane damage is a contributing factor to negative net salvage because with underground facilities, little, if any hurricane damage would occur. Witness Robinson asserted that PEF's historic net salvage of (6) percent is influenced by the significant levels of positive salvage during the 1970's and early 1980's. Witness Robinson averred that even if much if not most of this account will be abandoned in place, there will still be cost of removal because PEF will need to disconnect the plant.

We find that PEF's argument is somewhat persuasive, even with hurricane-related retirements included. We also agree with OPC that the net salvage should not be changed from 0 to (15) percent. Accordingly, we find that a net salvage of (5) percent is an appropriate compromise.

11. Account 370.00 – Meters

PEF proposed a relatively modest change in the curve from R2.5 to R0.5, a decrease in the average service life from 26 to 18 years, and a decrease in net salvage from (8) to (10) percent. OPC offered a proposal to increase the net salvage from (8) to (6) percent.

PEF witness Robinson testified that PEF's proposed 18-year average service life was based on his analysis of meter investment through December 31, 2007. Witness Robinson further testified that because of changing technology, the historical experience is considered conservative, and that 18 years is likely the maximum life in the future. OPC witness Pous provided no testimony pertaining to the average service life. We find that PEF's average service life proposal is reasonable based on the record evidence.

This account saw significant retirements in 2006, approximately $82 million. Of this amount, about $81 million of the retirements were related to replacing current meters with advanced meters, known as AMR (automatic meter reading) meters. According to PEF, historical net salvage for this account averaged (7) percent, "dramatically influenced by the change out of a significant quantity of meters during the last couple of years." Salvage amounts reflected in 2005 and 2006 were part of a formal salvage agreement PEF had with the vendor of the new meters. PEF witness Robinson asserted that with the meter project complete in 2007, he expects a return to a more typical cost for net salvage of (10) to (15) percent or higher.

OPC witness Pous proposed a change in net salvage to (6) percent because this is reflective of the net salvage percent achieved after 2005 retirements. Witness Pous also pointed to the experience of a utility in Texas that achieved a cost of removal per meter of $5.63. According to witness Pous, relying on a cost of removal per meter of $5.63 in PEF's territory would result in net salvage close to (6) percent. Therefore, he recommends (6) percent cost of removal.

We find that it is premature to decrease the net salvage, as PEF proposes. There has been a large change in the account with the addition of the new AMR meters. We do not find that using the information provided by witness Pous on the Texas utility's cost of removal per meter is sufficient to be used as support for an increase in net salvage. Additionally, the negative net salvage achieved by PEF for the $82 million of retirements was in part based on a salvage agreement with the vendor. We find that the appropriate approach at this time is to retain the current net salvage of (8) percent.

12. Account 371.00 – Installation on Customers Premises

PEF proposed no changes in its curve (R2) or its net salvage of 0 percent. PEF proposed to lengthen the average service life from 24 to 25 years. PEF witness Robinson considered an industry life of 19 years for this account. None of the intervenors offered a proposal for this account different from PEF's proposal.

13. Account 373.00 – Street Lighting and Signal Systems

PEF proposed a modest change in the curve from L2 to L1.5, an increase in the average service life from 17 to 20 years, and a decrease in net salvage from 0 percent to (20) percent. OPC proposed a decrease in net salvage from 0 percent to (5) percent.

OPC witness Pous averred that his proposed net salvage of (5) percent is both reasonable and appropriate, but that it does not give adequate weight to the potential of selling future street lighting systems. Witness Pous asserted that because of the future sale potential, his recommendation is conservative in favor of the Company.

PEF witness Robinson asserted that much of the gross salvage is likely attributable to return to stores, which is not true gross salvage. According to witness Robinson, there are no anticipated street lighting acquisitions. We find that OPC's arguments are more persuasive.

Account-Specific Analysis: General Plant

1. Account 390.00 – Structures and Equipment

PEF proposed a modest curve change from L0 to L0.5, a decrease in the average service life of four years from 28 to 24, and a decrease in net salvage, from 0 to (5) percent. OPC proposed a net salvage of 15 percent.

OPC argued that buildings can be anticipated to appreciate rather than depreciate in value. OPC witness Pous asserted that given the type of investment and PEF's proposed 24-year average service life, it is unreasonable and unrealistic to expect that relatively new buildings would require demolition and removal instead of a sale or reuse. Witness Pous opined that some form of net salvage is appropriate; therefore, he recommended a 15 percent net salvage. PEF argued that OPC ignores the realities of the operations of special use utility properties. Witness Robinson pointed to a $12 million retirement in 2007 which resulted in net salvage of more than (5) percent. We believe that both parties make reasonable arguments; however, we find OPC's argument is generally more persuasive. Therefore, we find that a compromise net salvage of 10 percent is appropriate.

2. Other General Plant Accounts

Pursuant to Rule 25-6.04361(5)(f), F.A.C., certain General Plant Accounts may use an amortization schedule. PEF proposed to amortize these accounts in accordance with the rule, continuing to use a seven-year amortization schedule for:

- Account 391.00 – Office Furniture and Equipment,
- Account 393.00 – Stores Equipment,

- Account 394.00 – Tools, Shop, and Garage Equipment,
- Account 395.00 – Laboratory Equipment,
- Account 397.00 – Communication Equipment; and
- Account 398.00 – Miscellaneous Equipment.

Under PEF's proposal there will be no change to the depreciation accrual. None of the intervenors offered a proposal for this account different from PEF's proposal.

For each of the following general accounts, PEF currently is using a depreciation rate approved in Order No. PSC-05-0945-S-EI, issued on September 28, 2005, in Docket No. 050078-EI, page 164. The accounts and their current depreciation rates are shown in Table 2.

Table 2: General Accounts with Specific Depreciation Rates

Account No.	Account Name	Depreciation Rate (percent)
392.10	Passenger Cars	8.7
392.20	Light Trucks	8.7
392.30	Heavy Trucks	4.8
392.40	Special Trucks	5.0
392.50	Trailers	1.7
396.00	Power Operated Equipment	5.8

PEF proposed to continue using the previously approved depreciation rates. There will be no change to the depreciation accrual under PEF's proposal. None of the intervenors offered any proposal for these accounts.

Conclusion

The approved remaining life, net salvage percent, allocated reserve percent, amortizations, and resulting rates for each transmission, distribution, and general plant account are contained in Table 3.

Table 3: Current and Commission Approved Parameters and Rates

ACCOUNT	CURRENT APPROVED* Average Remaining Life (Yrs.	CURRENT APPROVED* Net Salvage (%)	CURRENT APPROVED* Remaining Life Rate (%)	COMMISSION APPROVED Average Remaining Life (Yrs.	COMMISSION APPROVED Net Salvage (%)	COMMISSION APPROVED Allocated Reserve (%)	COMMISSION APPROVED Remaining Life Rate (%)
TRANSMISSION PLANT							
350.10 Land Rights	33.0	0	1.21	53.0	0	35.50	1.2
352.00 Structures and Improvements	35.0	(15)	1.87	57.0	(15)	32.74	1.4
353.10 Station Equipment	29.0	0	1.78	43.0	0	22.00	1.8
353.20 Station Equipment-Station Control	5.0	0	0.90	7.2	0	91.80	1.1
354.00 Towers and Fixtures	27.0	(25)	1.72	31.0	(25)	84.19	1.3
355.00 Poles and Fixtures	22.0	(25)	2.72	29.0	(25)	30.46	3.3
356.00 Overhead Conductors and Devices	21.0	(30)	2.26	43.0	(20)	39.37	1.9
357.00 Underground Conduit	18.8	0	1.28	16.9	0	80.29	1.2
358.00 Underground Conductors & Devices	16.8	(3)	1.13	47.0	0	6.32	2.0
359.00 Roads and Trails	31.0	0	0.76	69.0	0	35.81	0.9
DISTRIBUTION PLANT							
360.10 Land Rights	31.0	0	1.19	67.0	0	7.64	1.4
361.00 Structures and Improvements	39.0	(5)	1.86	64.0	(10)	19.06	1.4
362.00 Station Equipment	27.0	(15)	2.57	51.0	(10)	18.20 **	1.8
364.00 Poles, Towers and Fixtures	20.0	(35)	3.86	18.8	(35)	55.95	4.2
365 Overhead Conductors and Devices	20.0	(15)	2.66	27.0	(20)	46.28 **	2.7
366.00 Underground Conduit	35.0	0	1.78	56.0	(5)	16.86 **	1.6
367.00 Underground Conductors and Devices	26.0	(5)	3.19	25.0	(5)	31.20	3.0
368.00 Line Transformers	15.2	(5)	3.38	21.0	(10)	49.31	2.9
369.10 Services-Overhead	24.0	(50)	2.86	15.4	(40)	77.64	4.0
369.20 Services-Underground	26.0	0	2.76	35.0	(5)	26.89	2.2
370.00 Meters	19.6	(8)	3.57	13.5	(8)	27.00 **	6.0
370.10 Meters-Energy Conservation	10.3	0	0.00				
371.00 Installation on Customers Premises	25.0	0	3.93	17.6	0	36.10	3.6
373.00 Street Lighting and Signal Systems	9.1	0	4.59	12.3	(5)	67.29	3.1
GENERAL PLANT							
389.00 Land Rights							
390.00 Structures and Improvements	26.0	0	3.48	17.8	10	24.00	3.7
391.00 Office Furniture and Equipment			14.30	7 Year Amortization			
Transportation Equipment							
392.10 Passenger Cars			8.70				8.70%
392.20 Light Trucks			8.70				8.70%
392.30 Heavy Trucks			4.80				4.80%
392.40 Special Trucks			5.00				5.00%
392.50 Trailers			1.70				1.70%
393.00 Stores Equipment			14.30	7 Year Amortization			
394.00 Tools, Shop and Garage Equipment			14.30	7 Year Amortization			
395.00 Laboratory Equipment			14.30	7 Year Amortization			
396.00 Power Operated Equipment			5.81				5.8
397.00 Communication Equipment			14.30	7 Year Amortization			
398.00 Miscellaneous Equipment			14.30	7 Year Amortization			

* Order No. PSC-05-0945-S-EI, Docket No. 050078-EI.

** Reserve after Commission approved reallocations.

H. Calculated Theoretical Reserves

The theoretical reserve is the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied. The book reserve is the amount actually recovered to date. The formula for the prospective theoretical reserve is provided in Rule 25-6.0436(4)(k), F.A.C. Using this formula and the life and salvage components we have previously approved, we find a reserve imbalance of $697.4 million, as shown in Table 4:

Table 4: Reserve Imbalance

	(million)
Steam Production	$173.5
Nuclear Production	102.5
Other Production	55.8
Transmission	99.5
Distribution & General	266.1
Total Reserve Imbalance	$697.4

I. Corrective Reserve Measures

We note that all witnesses agreed that the remaining life depreciation methodology recovers the net remaining investment over the average remaining life of the associated assets. We observe that the parties also agreed that:

- Depreciation rates should be based on the best information available.
- A reserve surplus of at least $646 million exists based on the theoretical reserve calculation.
- The reserve surplus serves to reduce PEF's future depreciation expenses.

We believe the crux of this issue is whether the reserve imbalance should be corrected over the remaining life or a shorter period of time. To this end, PEF witnesses Robinson and Garrett contended that the remaining life depreciation approach to resolve reserve imbalances is the norm and there is no reason to deviate. OPC witness Pous and FIPUG witness Pollock asserted that the magnitude of the reserve variance warrants a corrective approach other than the normal remaining life depreciation approach. We note that PEF witness Vilbert agreed that it would be best if there were no reserve imbalance.

We observe that the NARUC depreciation manual sets forth two accepted methods for calculating a theoretical depreciation reserve: the prospective method and the retrospective method. The prospective method is required in our depreciation study rule, Rule 25-6.0436(6)(d), F.A.C. PEF witness Robinson and OPC witness Pous acknowledged the NARUC manual as setting forth standard depreciation practices.

The NARUC depreciation manual states that if a reserve imbalance is material, common methods for correcting the imbalance are either through an amortization over an abbreviated period of time or remaining life depreciation rates. We note that the NARUC depreciation manual does not quantify what constitutes a "material" imbalance. In its brief, PEF argued that amortization of reserve deficiencies caused by plant retiring earlier than the average service life is what NARUC meant when it referenced amortization as a common method to address reserve imbalances, because amortization in this instance more closely follows the matching principle. We disagree with PEF's assertion. The NARUC depreciation manual is clear that amortization is an acceptable method for correcting material reserve imbalances. We believe that if there were exceptions to the use of amortization, as PEF implied, the NARUC depreciation manual would have so stated. Moreover, we agree with FRF that it makes little sense that the NARUC depreciation manual would support a policy that violated GAAP or represented retroactive ratemaking as alleged by PEF. While PEF apparently agreed with the recovery of investments retiring earlier than their average service life, it did not address the negative reserves that currently exist with the retirement of Bartow, Avon Park, meters, or power operated equipment.

FIPUG argued in its brief that PEF's claim that amortization of a reserve imbalance is retroactive ratemaking is without merit. FIPUG asserted that retroactive ratemaking involves going back in the past and changing an approved rate. FIPUG cited in its brief to City of Miami v. FPSC, 208 So. 2d 249, 259-260 (Fla. 1968), for the proposition that retroactive ratemaking involves the application of new rates to past consumption.

FIPUG asserted that in the instant case, the issue is the setting of PEF's prospective depreciation rates. FIPUG contended that revised depreciation rates will be applied going forward and an amortization of a reserve imbalance going forward is not retroactive ratemaking. We agree. Depreciation rates are designed and applied prospectively and so is the correction of any reserve transfers or correction of a reserve imbalance via an amortization. The calculation of the theoretical reserve is prospective, as defined in Rule 25-6.0436, F.A.C.

1. Intergenerational Inequity

The intervenors claimed that the existence of PEF's reserve imbalance indicates that past and current customers have paid more than their fair share of depreciation expenses and that future customers will therefore pay less than their fair share. In contrast, PEF contended that the existing imbalance would inure to the benefit of current and future customers because the depreciation rates will be lower than they otherwise would be.

We believe that the very presence of a reserve imbalance indicates the existence of an intergenerational inequity. Based on what is known today, the estimates of yesterday are now viewed as being too short. PEF has lengthened the life span estimates for its production plants.

Net salvage estimates have changed. Does that mean that past life and salvage estimates were wrong? We believe it does not. Disregarding that settlements were reached in 2002[22] and 2005[23] that addressed depreciation and many other matters, the last time this Commission actually conducted a thorough review and analysis of PEF's depreciation parameters was in 1997. Conditions, Company plans, and regulatory requirements change. OPC witness Pous acknowledged that depreciation parameters change over time simply because depreciation is a projection of anticipated events in the future. FRF recognized in its brief that in a depreciation study review, a goal has been to align the actual and theoretical reserve positions for all accounts.

We agree with PEF witness Robinson and OPC witness Pous that it is unlikely there would ever be a time when there is no reserve imbalance, simply because as time passes, more information is known and hopefully better estimates of life and salvage can be determined. That said, there is no reason for not taking some action to correct reserve imbalances, where possible, either through reserve transfers or an amortization. We also believe it is the magnitude of the reserve imbalance that dictates what action is taken.

We agree with PEF that current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates. If the reserve surplus is reduced, the depreciation reserve will increase thereby, all things remaining equal, causing depreciation rates and future revenue requirements to naturally increase. At the present time, it can be argued that the current reserve surplus results in prospective depreciation rates that are artificially low. This is the beauty or the beast of the remaining life rate methodology. A surplus means that more than enough has been recovered under present expectations, and so there is a smaller amount left to be recovered over the average remaining life. Conversely, the presence of a reserve deficit means that not enough has been recovered to date, so the depreciation rate must increase to make up the difference in the future.

2. Previous Commission Orders Regarding Reserve Imbalances

We observe that the intervenors contended that our past orders support a position that reserve imbalances have historically been recovered over a period of time that is shorter than the average remaining life. PEF, on the other hand, contended that the orders referenced by the intervenors refer to reserve deficiencies, not to reserve surpluses as exist in this case, and so these orders are not pertinent. We believe this is a distinction without a difference.

The existence of a negative reserve caused by plant retiring earlier than the related average service life creates a positive component in rate base on which the Company is allowed to earn a return until it is corrected. We believe that negative reserves reflect an overstatement of rate base. We presume that PEF undoubtedly concurs or it would not have made the statement that amortization in these circumstances is warranted.

[22] Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket Nos. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (FPC 2002 Rate Case Settlement Order).

[23] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc. (PEF 2005 Rate Case Settlement Order).

We agree with OPC witness Pous that whether the imbalance is a deficiency or a surplus, the rate base is misstated and should be corrected. By design, the remaining life rate self-adjusts and corrects any reserve imbalance over the remaining life of the associated plant. Historically, this Commission has addressed reserve imbalances through the use of reserve transfers or allocations. For electric companies, in light of possible cross-subsidies between functions, we have limited transfers between accounts within the same function. In other words, transfers are only made between accounts within the production function, transfers between accounts within the transmission function, and so on.

PEF recognized our practice of using reserve transfers between accounts to correct reserve imbalances. PEF witness Vilbert also acknowledged that this practice was not a restatement of depreciation reserve, but rather a reallocation among accounts. However, PEF asserted that reserve transfers were not needed or were inappropriate to use in its depreciation study. PEF witness Garrett contended that such reserve correction would effectively represent reserve transfers that may not be compliant with Generally Accepted Accounting Principles (GAAP), although this is contradicted by PEF witness Vilbert. We also note that, according to PEF's outside auditors' guidance, transfers of depreciation expense from transmission or distribution accounts to generating accounts are generally acceptable under Financial Accounting Standard (FAS) 71, as long as the transfers do not result in negative depreciation for any account. Thus, we believe that the practice of reserve transfers between accounts does not violate GAAP.

In its brief, PEF recognized that we have previously approved accelerated depreciation when faced with potential changes in the regulatory environment as a result of possible deregulation. In this instance, we stated that the accounting adjustments "will facilitate the establishment of a level 'accounting' playing field between [the utility] and possible non-regulated competitors."[24] We note that the expected competition did not come to fruition. We do not believe that this means that an error was made. Just as the Commission reacted to events it thought were likely to take place, we can react to existing circumstances by amortizing PEF's reserve imbalance over a shorter period of time than the remaining life. There is nothing in our prior order or any other order that prohibits us from addressing the reserve imbalance identified in this proceeding in a manner different from the remaining life rate design approach.

In Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket Nos. 000824-EI, <u>In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light</u> and 020001-EI, <u>In re: Fuel and purchased power cost recovery clause with generating performance incentive factor</u> (PEF 2002 Rate Case Settlement Order), the Company agreed to a credit to depreciation expense, which is tantamount to an annual amortization. PEF opposed the intervenors' current proposals, which are similar approaches. We recognize, as pointed out by PEF in its brief, that settlements involve give and take. We also agree with PEF that a settlement is not binding precedent on the Commission. That said, we are puzzled why PEF would have agreed to a credit to depreciation expense if it indeed believed that doing so was in violation of GAAP and Federal Energy Regulatory Commission (FERC) guidelines.

[24] Order No. PSC-97-0499-FOF-EI, issued April 29, 1997, in Docket No. 970410-EI, <u>In re: Proposal to extend plan for recording of certain expenses for years 1998 and 1999 for Florida Power & Light Company</u>, p. 3.

FIPUG argued in its brief that the current proposed amortization of the reserve imbalance is conceptually the same as our prior actions for Florida Power & Light Company (FPL). By Order No. PSC-96-0461-FOF-EI,[25] FPL was authorized to record additional depreciation expense of $126 million in 1995, an additional $30 million beginning in 1996, and additional expenses in 1996 and 1997 based on differences between actual and forecasted revenues to correct a $175.3 million reserve deficiency existing in FPL's nuclear production facilities, with any residual expense to be applied to the other production facilities. In its 1997 depreciation study,[26] Florida Power Corporation (FPC) was ordered to amortize the gain realized from the sale of a combustion turbine (CT), to be used to offset a reserve deficiency at the Suwannee Peaking Plant. In the FPL 2005 Rate Case Settlement Order, FPL was authorized to amortize up to $125 million annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Settlement. FIPUG asserted that the material reserve surplus in the instant case warrants similar adjustments to restore generational equity and to help mitigate the impact of the proposed base rate increases. FIPUG's arguments do not recognize that in the cited FPL cases, the recording of additional depreciation expense to correct perceived reserve deficiencies was made in the context of ensuring the Company would earn within its authorized rate of return. For the FPC case cited, we note that rather than amortizing the proceeds from the sale of the CT unit over five years, we held that the proceeds should have been recognized as gross salvage and recorded as a credit to the depreciation reserve. Because the sale proceeds exceeded the net unrecovered costs associated with the retired CT, the surplus was transferred to help offset a reserve deficiency for the Suwannee Peaking Plant.

FRF argued in its brief that our declared policy with respect to reserve imbalances is to correct them as soon as possible without adversely impacting a company's ability to earn a fair and reasonable return.[27] FRF noted that this Commission also targeted overearnings in the past to book additional depreciation expense, thereby lowering reported earnings and bringing them in line with the allowed rate of return. In the instant proceeding, we are setting a new rate of return for PEF. In deciding whether to amortize the reserve imbalance as the intervenors proposed, we will also consider any negative impacts such an amortization will have on PEF's financial integrity and the ratepayers.

3. GAAP

PEF witnesses Garrett and Vilbert asserted that amortization of a reserve imbalance violates GAAP, specifically FAS 154. The witnesses contended that retroactive depreciation adjustments and reversal of prior period depreciation expenses are not GAAP-compliant. While this may be, we do not believe the intervenors' proposals constitute retroactive adjustments or the reversal of depreciation expenses. The intervenors have not claimed that PEF's prior

[25] Order No. PSC-96-0461-FOF-EI, issued April 2, 1996, in Docket No. 950359-EI, In re: Petition to establish amortization schedule for nuclear generating units to address potential for stranded investment by Florida Power & Light Company.
[26] Order No. PSC-98-1723-FOF-EI, issued December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study by Florida Power Corporation. (FPC 1997 Depreciation Order).
[27] Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 010699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

depreciation rates were incorrect. The existing reserve imbalance is due to changes in prospective life and salvage estimates. Depreciation rates are prospective in nature and so is any correction to the reserve imbalance.

PEF witness Garrett testified that FAS 154 does not necessarily limit how regulated companies establish their cost of service, and this Commission has considerable latitude in its ratemaking endeavors. While FAS 154 governs financial accounting, it does not govern regulatory accounting. In response to discovery, PEF stated that as long as an action did not result in negative depreciation for any account, the action would be generally acceptable under FAS 71. PEF witness Garrett testified to the same point.

When asked at the hearing whether remaining life rates restated depreciation expense, PEF witness Garrett responded in the negative. We disagree. If the remaining life rate is lower prospectively than the currently approved depreciation rate, the reserve is being restated over the newly-established remaining life. The very nature of remaining life depreciation rates is that they self-adjust to recover net unrecovered investments over the applicable remaining life. Under PEF's logic then, remaining life depreciation rates would be considered retroactive, since the methodology, by design, restates the reserve.

4. Financial Integrity

Regarding the intervenors' amortization proposals, PEF asserted that depreciation expense will be reduced during each year of the amortization period and rate base will accordingly increase, thereby increasing the return to which the Company is entitled. The resulting reduction in cash flow will require PEF to raise additional capital to meet its construction budget. This will likely lead to higher transaction costs associated with acquiring new capital for capital investments. However, we note that since PEF's forecast of capital expenditures is in excess of its cash flows, it already plans to go to the market to raise more debt and equity.

PEF also cautioned that the intervenors' proposed amortization would increase its cost of capital due to increased investor uncertainty. Moreover, such an amortization would likely weaken PEF's credit metrics and result in an increase in its cost of debt and cost of equity on a going forward basis. A higher cost of capital applied to a larger rate base yields higher customer rates. As illustrated by PEF witness Vilbert, the intervenors' proposals would decrease revenue requirements in the short term, but would increase revenue requirements about $200 million between year 4 and year 5. We note that witness Vilbert did not provide a sensitivity analysis that quantified the minimum level of reduced depreciation cash flow that would not have an adverse affect on the Company's financial integrity.

The intervenors' proposed adjustment for the theoretical reserve surplus will lower PEF's cash flow metrics. Witness Lawton demonstrated that PEF's CFO/Interest will decrease from 4.9x to 4.0x and its CFO/Debt will decrease from 35 percent to 29 percent based on PEF receiving the full amount of its requested rate increase except for the amortization. However, the proposed adjustment does not take into account any other adjustments that will impact cash flow. By itself, the intervenors' proposed adjustment would not lower PEF's financial metrics below the standards required for its current credit rating. Then again, the proposed adjustment in combination with other adjustments that reduce cash flow could result in PEF's credit metrics falling below those required for an investment grade rating. For example, OPC's proposed $35 million revenue reduction will result in a CFO/Interest of 3.8x and a CFO/Debt of 18 percent. The resulting financial metrics would not meet the standards for Moody's financial metrics for PEF's current credit rating of A3. While there is no one key financial metric that determines a particular bond rating level, these financial ratios are helpful in evaluating a company's financial integrity and liquidity for assessing its credit quality.

5. Conclusion

In the review of any depreciation study, the reserve position of the company should be reviewed. Indeed, the depreciation study rule, Rule 25-6.0436, F.A.C., requires a calculation of the prospective theoretical reserve for each account. As noted previously, this is the first thorough review of PEF's reserve position since 1997. Reserve imbalances are to be expected in over 10 years' time. As previously discussed, our calculation indicates a total reserve imbalance of $697.4 million.

PEF reports net unrecovered investments associated with the retirement of the Bartow Plant and Avon Park steam plants, the CR 4 & 5 upgrade, and the CR 3 steam generator. There are also negative reserves associated with the retirement of meters and power operated equipment that retired earlier than the associated expected life. The initial appropriate corrective action is to allocate some of the reserve surplus existing in the production and distribution plant functions to correct these net unrecovered costs.

We reviewed the reserve position of PEF's accounts. Based on our calculations, the reserve surplus existing for Anclote, CR 1 & 2, and CR 4 & 5 can be transferred to correct the reserve deficiencies existing at Suwannee, to correct the negative reserves at the retired Bartow and Avon Park sites, and to offset the unrecovered net investments at CR 4 & 5 associated with the retirements planned in connection with the upgrade. For CR 3, an allocation of reserve from Account 325, Miscellaneous Power Plant Equipment, shall be made to offset the calculated reserve deficiency in Account 312, Reactor Plant Equipment, and to recover the net investments associated with the steam generator retirement. Additionally, reserve allocations shall be made among the accounts of the other production sites at Avon Park, Bartow, Debary, Debary P7-1, Higgins, Hines Energy Complex (Units 1-4), Intercession City (#11, P1-P6, and P12-P14), Turner, Rio Pinar, and Suwannee to bring their respective book reserve positions more in line with the theoretically correct levels.

The reserve surpluses existing in the Distribution Plant function, specifically in Account 362, Station Equipment; Account 365, Overhead Conductors and Devices; and Account 366, Underground Conduit, shall be transferred to correct the calculated reserve deficiencies in Account 367, Underground Conductors and Devices, and the negative reserves in Account 370, Meters, and Account 396, Power Operated Equipment. These transfers will bring the reserve for both underground conductors and devices and meters to their theoretically correct levels, and correct the negative reserve in power operated equipment.

Our approved reserve allocations are shown in Table 5. The question remains what additional action should be taken with respect to the remaining calculated reserve surplus of $690 million. Balancing the need to correct the reserve surplus with concerns regarding reduced cash flow and financial integrity, we find that $23 million of the reserve surplus shall be amortized over four years in the annual amount of $5,840,613, thereby bringing the increase in annual revenue requirement to zero. The remaining $667 million reserve surplus shall be recovered through the remaining life rate design. In light of the minimal amount of reserve surplus being amortized, we believe the impact to depreciation rates is negligible. For this reason and for purposes of simplicity, we will not recalculate the depreciation rates previously approved.

Table 5: Reserve Allocations

	Book Reserve Est. 12/31/09 ($)	Theoretical Reserve ($)	Imbalance ($)	Approved Allocation ($)	Allocated Reserve ($)
PRODUCTION PLANT					
Anclote Steam					
312 Boiler Plant Equipment	76,215,849	64,643,696	11,572,153	(4,102,074)	72,113,775
314 Turbogenerator Units	62,869,369	66,971,443	(4,102,074)	4,102,074	66,971,443
Bartow Steam					
	(15,690,209)	0	(15,690,209)	15,690,209	0
Avon Park					
	(5,410,811)	0	(5,410,811)	5,410,811	0
Crystal River 1 & 2 Steam					
312 Boiler Plant Equipment	125,928,327	129,194,659	(3,266,332)	3,266,332	129,194,659
314 Turbogenerator Units	97,505,207	80,652,588	16,852,619	(3,266,332)	94,238,875
Crystal River 4 & 5 Steam					
311 Structures and Improvements	94,380,530	70,931,184	23,449,346	(6,602,228)	87,778,302
312 Boiler Plant Equipment	353,494,603	317,701,142	35,793,461	(16,397,008)	337,097,595
314 Turbogenerator Units	152,123,615	87,432,013	64,691,602	(5,044,194)	147,079,421
315 Accessory Electric Equipment	59,293,343	35,188,257	24,105,086	(1,470,314)	57,823,029
316 Misc. Power Plant Equipment	9,493,042	5,724,742	3,768,300	(467,491)	9,025,551
312 Crystal River 4 & 5 Upgrade	15,332,125	21,192,417	(5,860,292)	5,860,292	21,192,417
Suwannee River Steam					
311 Structures and Improvements	4,745,118	4,842,866	(97,748)	97,748	4,842,866
312 Boiler Plant Equipment	14,003,681	14,107,051	(103,370)	103,370	14,107,051
314 Turbogenerator Units	10,220,962	12,523,891	(2,302,929)	2,302,329	12,523,291
315 Accessory Electric Equipment	1,983,090	2,499,566	(516,476)	516,476	2,499,566
Crystal River Unit 3					
322 Reactor Plant Equipment	117,836,426	128,461,561	(10,625,135)	10,625,135	128,461,561
325 Misc. Power Plant Equipment	36,335,036	13,647,920	22,687,116	(13,246,624)	23,088,412
322 Crystal River Unit 3 Steam Gen. Ret.	(2,621,489)	0	(2,621,489)	2,621,489	0

Table 5: Reserve Allocations

	Book Reserve Est. 12/31/09	Theoretical Reserve	Imbalance	Approved Allocation	Allocated Reserve
	($)	($)	($)	($)	($)
PRODUCTION PLANT					
Avon Park Peaking					
342 Fuel Holders, Prod. and Accessories	481,251	521,912	(40,661)	40,661	521,912
343 Prime Movers	4,726,338	4,768,751	(42,413)	42,413	4,768,751
344 Generators	1,667,410	1,288,579	378,831	(39,393)	1,628,017
346 Misc. Power Plant Equipment	101,380	57,699	43,681	(43,681)	57,699
Bartow Peaking					
342 Fuel Holders, Prod. and Accessories	1,083,322	1,105,444	(22,122)	22,122	1,105,444
343 Prime Movers	10,599,451	6,711,392	3,888,059	(91,128)	10,508,323
344 Generators	4,914,423	4,983,429	(69,006)	69,006	4,983,429
Debary Peaking					
341 Structures and Improvements	3,642,049	3,558,170	83,879	(83,879)	3,558,170
342 Fuel Holders, Prod. and Accessories	4,431,240	5,045,248	(614,008)	614,008	5,045,248
343 Prime Movers	19,428,389	18,776,338	652,051	(652,051)	18,776,338
344 Generators	6,295,677	7,119,836	(824,159)	824,159	7,119,836
345 Accessory Electric Equipment	3,608,765	4,375,471	(766,706)	766,706	4,375,471
346 Misc. Power Plant Equipment	380,148	422,416	(42,268)	42,268	422,416
Debary Peaking P7-1 (New)					
341 Structures and Improvements	2,338,183	2,614,264	(276,081)	276,081	2,614,264
342 Fuel Holders, Prod. and Accessories	3,754,425	4,983,707	(1,229,282)	1,229,282	4,983,707
343 Prime Movers	32,719,600	35,779,435	(3,059,835)	3,059,835	35,779,435
344 Generators	9,180,736	10,453,448	(1,272,712)	1,272,712	10,453,448
345 Accessory Electric Equipment	2,565,188	2,885,535	(320,347)	320,347	2,885,535
346 Misc. Power Plant Equipment	474,257	373,402	100,855	(100,855)	373,402
Higgins Peaking					
341 Structures and Improvements	723,315	642,211	81,104	(81,104)	642,211
342 Fuel Holders, Prod. and Accessories	1,856,757	1,365,454	491,303	(491,303)	1,365,454
343 Prime Movers	10,370,006	7,971,142	2,398,864	(2,398,864)	7,971,142
344 Generators	2,659,824	2,216,028	443,796	(443,796)	2,216,028
345 Accessory Electric Equipment	2,363,230	2,044,372	318,858	(318,858)	2,044,372
346 Misc. Power Plant Equipment	153,915	83,166	70,749	(70,749)	83,166

Table 5: Reserve Allocations

	Book Reserve Est. 12/31/09 ($)	Theoretical Reserve ($)	Imbalance ($)	Approved Allocation ($)	Allocated Reserve ($)
PRODUCTION PLANT					
Hines Energy Complex					
341 Structures and Improvements	16,163,733	14,550,359	1,613,374	(1,613,374)	14,550,359
342 Fuel Holders, Prod. and Accessories	8,064,414	6,698,241	1,366,173	(1,366,173)	6,698,241
343 Prime Movers	67,537,783	49,799,172	17,738,611	(14,706,720)	52,831,063
344 Generators	23,270,877	14,920,999	8,349,878	(8,349,878)	14,920,999
345 Accessory Electric Equipment	8,245,010	6,715,562	1,529,448	(1,529,448)	6,715,562
346 Misc. Power Plant Equipment	1,966,999	1,105,697	861,302	(861,302)	1,105,697
Hines Energy Complex Unit # 2					
341 Structures and Improvements	5,894,406	9,615,694	(3,721,288)	3,721,288	9,615,694
342 Fuel Holders, Prod. and Accessories	1,185,395	2,884,597	(1,699,202)	1,699,202	2,884,597
343 Prime Movers	23,202,575	21,413,557	1,789,018	(1,789,018)	21,413,557
344 Generators	15,973,036	8,533,642	7,439,394	(7,439,394)	8,533,642
345 Accessory Electric Equipment	7,418,934	3,167,170	4,251,764	(4,251,764)	3,167,170
346 Misc. Power Plant Equipment	799,922	462,059	337,863	(337,863)	462,059
Hines Energy Complex Unit # 3					
341 Structures and Improvements	1,592,127	3,080,936	(1,488,809)	1,488,809	3,080,936
342 Fuel Holders, Prod. and Accessories	1,408,545	6,611,548	(5,203,003)	5,203,003	6,611,548
343 Prime Movers	26,408,999	42,351,473	(15,942,474)	15,942,474	42,351,473
344 Generators	7,457,674	15,294,750	(7,837,076)	7,837,076	15,294,750
345 Accessory Electric Equipment	3,398,685	5,862,020	(2,463,335)	2,463,335	5,862,020
346 Misc. Power Plant Equipment	395,458	420,209	(24,751)	24,751	420,209
Hines Energy Complex Unit #4					
341 Structures and Improvements	1,722,696	2,383,184	(660,488)	660,488	2,383,184
342 Fuel Holders, Prod. and Accessories	1,315,408	1,218,988	96,420	(96,420)	1,218,988
343 Prime Movers	16,700,578	14,993,301	1,707,277	(601,147)	16,099,431
344 Generators	220,582	297,811	(77,229)	77,229	297,811
345 Accessory Electric Equipment	2,027,644	2,104,421	(76,777)	76,777	2,104,421
346 Misc. Power Plant Equipment	277,827	160,900	116,927	(116,927)	160,900

Table 5: Reserve Allocations

	Book Reserve Est. 12/31/09 ($)	Theoretical Reserve ($)	Imbalance ($)	Approved Allocation ($)	Allocated Reserve ($)
PRODUCTION PLANT					
Intercession City Peak # 11					
341 Structures and Improvements	589,330	622,159	(32,829)	32,829	622,159
342 Fuel Holders, Prod. and Accessories	686,299	716,547	(30,248)	30,248	716,547
343 Prime Movers	6,741,758	6,081,279	660,479	(350,504)	6,391,254
344 Generators	1,260,949	1,364,008	(103,059)	103,059	1,364,008
345 Accessory Electric Equipment	1,710,592	1,894,960	(184,368)	184,368	1,894,960
Intercession City Peak P1-P6					
341 Structures and Improvements	1,428,302	2,593,323	(1,165,021)	1,165,021	2,593,323
342 Fuel Holders, Prod. and Accessories	329,450	2,253,187	(1,923,737)	1,923,737	2,253,187
343 Prime Movers	6,640,334	16,997,925	(10,357,591)	10,357,591	16,997,925
344 Generators	1,696,408	3,453,769	(1,757,361)	1,757,361	3,453,769
345 Accessory Electric Equipment	1,242,287	2,273,880	(1,031,593)	1,031,593	2,273,880
Intercession City Peak P12-P14					
341 Structures and Improvements	959,878	387,972	571,906	(571,906)	387,972
342 Fuel Holders, Prod. and Accessories	3,031,543	1,633,775	1,397,768	(1,397,768)	1,633,775
343 Prime Movers	29,372,330	17,043,008	12,329,322	(11,476,675)	17,895,655
344 Generators	7,983,237	4,587,379	3,395,858	(1,757,361)	6,225,876
345 Accessory Electric Equipment	3,497,323	1,969,780	1,527,543	(1,031,593)	2,465,730
Turner Peaking					
342 Fuel Holders, Prod. and Accessories	1,920,928	2,529,788	(608,860)	608,860	2,529,788
343 Prime Movers	11,747,483	9,678,258	2,069,225	(790,421)	10,957,062
344 Generators	3,629,741	3,903,199	(273,458)	273,458	3,903,199
345 Accessory Electric Equipment	1,834,677	1,924,404	(89,727)	89,727	1,924,404
346 Misc. Power Plant Equipment	297,969	187,933	110,036	(80,567)	217,402
Rio Pinar Peaking					
342 Fuel Holders, Prod. and Accessories	331,204	336,004	(4,800)	4,800	336,004
343 Prime Movers	1,941,216	1,594,012	347,204	(119,291)	1,821,925
344 Generators	332,948	367,281	(34,333)	34,333	367,281
345 Accessory Electric Equipment	297,770	372,784	(75,014)	75,014	372,784
346 Misc. Power Plant Equipment	5,522	10,666	(5,144)	5,144	10,666

Table 5: Reserve Allocations

	Book Reserve Est. 12/31/09 ($)	Theoretical Reserve ($)	Imbalance ($)	Approved Allocation ($)	Allocated Reserve ($)
PRODUCTION PLANT					
Suwannee Peaking					
342 Fuel Holders, Prod. and Accessories	2,146,015	2,218,473	(72,458)	72,458	2,218,473
343 Prime Movers	15,174,555	12,437,173	2,737,382	(20,648)	15,153,907
346 Misc. Power Plant Equipment	124,395	72,585	51,810	(51,810)	72,585
Total Production Plant Reserve Reallocations				0	
DISTRIBUTION & GENERAL PLANT					
362 Station Equipment	126,465,254	94,355,541	32,109,713	(32,109,713)	94,355,541
365 Overhead Conductors & Devices	260,994,428	172,097,275	88,897,153	(3,221,612)	257,772,816
366 Underground Conduit	47,496,702	32,318,664	15,178,038	(12,104,083)	35,392,619
370 Meters	(11,443,192)	32,770,604	(44,213,796)	44,213,796	32,770,604
396 Power Operated Equipment	(3,221,612)	0	(3,221,612)	3,221,612	0
Total Distribution & Plant Reserve Allocations				0	

J. Implementation Date

We find that the implementation date for the revised depreciation rates, capital recovery schedules, and amortization schedules shall be January 1, 2010.

V. FOSSIL DISMANTLEMENT COST STUDY

A. Annual Dismantlement Provision

Fossil dismantlement for PEF was last addressed in Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In Re: Petition for rate increase by Progress Energy Florida. The parties to that proceeding reached a stipulation of all issues. We later approved the stipulation and settlement agreement. As part of the approved stipulation, PEF continued zero annual accruals to its reserve for fossil dismantlement. The Stipulation is effective through the last billing cycle in December 2009. In accordance with the above referenced order, PEF filed its fossil dismantlement study on July 31, 2009.

PEF's 2008 fossil dismantlement study filed in this proceeding indicates a need to adjust PEF's current annual fossil dismantlement accrual, which is currently set at zero. This 2008 dismantlement study represents an update of PEF's base dismantlement costs, contingency, and inflation forecasts. PEF contends an annual accrual of $3,845,221 is required to meet its fossil dismantlement needs. We find PEF has made a prima facie case for some increase from zero to its annual fossil dismantlement accrual. Accordingly, we approve a January 1, 2010, implementation date for any revised annual fossil dismantlement accrual to take effect. Based on the table below, we find that PEF's currently approved annual dismantlement provision shall be revised.

A comparison of cost estimates for fossil dismantlement from the prior 2004 study (projected 2006 test year) and the 2008 study (projected 2010 test year) is shown below.

Table 6: Fossil Fuel Dismantlement Cost Estimates

	DISMANTLEMENT 2004 COST STUDY (2006 DOLLARS)[28]	DISMANTLEMENT 2008 COST STUDY (2010 DOLLARS)	VARIANCE BETWEEN STUDIES
	($)	($)	($)
Anclote	15,032,810	10,135,582	(4,897,228)
Avon Park Gas Turbine	626,166	171,048	(455,118)
Bartow - Steam	25,501,460	28,097,998	2,596,538
Bartow - CT	9,063,700	10,707,360	1,643,660
Bartow-Anclote Pipeline	976,106	346,322	(629,784)
Bartow - CC	0	449,770	449,770
Bayboro	1,791,891	978,450	(813,441)
Crystal River South Units 1 & 2	37,966,224	32,097,229	(5,868,995)
Crystal River North Units 4 & 5	28,133,314	26,630,663	(1,502,651)
Crystal River Common	8,589,643	12,514,898	3,925,255
Crystal River Helper	3,316,175	4,153,459	837,284
Crystal River Mariculture	1,153,299	1,571,058	417,759
Debary Gas Turbine units 1 - 6	2,854,274	595,998	(2,258,276)
Debary Gas Turbine units 7 - 10	5,007,768	7,248,325	2,240,557
Higgins - Steam	5,948,848	0	(5,948,848)
Higgins - Peaker	553,259	343,512	(209,747)
Hines PB1	1,681,716	560,201	(1,121,515)
Hines PB2	6,203,936	560,201	(5,643,735)
Hines PB3	0	560,201	560,201
Hines PB4	0	661,543	661,543
Intercession City Units 1 - 6	1,625,509	457,098	(1,168,411)
Intercession City Units 7 -10	3,133,121	1,720,105	(1,413,016)
Intercession City Units 11	576,567	198,446	(378,121)
Intercession City Units 12 -14	2,408,368	4,760,719	2,352,351
Port St. Joe	265,285	0	(265,285)
Rio Pinar	664,211	322,364	(341,847)
Suwannee - Steam units 1 - 3	13,282,882	14,060,964	778,082
Suwannee - CT 1 - 3	480,297	279,534	(200,763)
Tiger Bay Combined Cycle	1,850,390	389,942	(1,460,448)
Turner Gas Turbine Units 1 - 2	8,210,467	0	(8,210,467)
Turner Gas Turbine Units 3 - 4	282,905	24,044	(258,861)
Turner - Steam	728,937	432,155	(296,782)
University of Florida Gas Turbine	1,324,447	301,464	(1,022,983)
Totals	**189,233,975**	**161,330,653**	**(27,903,322)**

[28] The 2004 study was filed, but the accrual was set at zero per paragraph 11 of the stipulation agreement in Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In Re: Petition for rate increase by Progress Energy Florida.

B. Corrective Reserve Measures for Fossil Dismantlement

PEF's 2008 fossil dismantlement study contains proposed adjustments to correct reserve imbalances as a result of updating its fossil dismantlement cost estimates. It has proposed that reserve surpluses for Avon Park Gas Turbine, Higgins, Inglis Steam, Port St. Joe Gas Turbine, and Turner Steam plants, be transferred to Bartow Steam, Suwannee Steam Units, Bartow-Anclote Pipeline, and CR 1 & 2 plants. We have consistently approved reserve transfers in fossil dismantlement studies. PEF's last reserve transfer was approved by Order No. PSC-01-2386-PAA-EI, issued December 10, 2001, in Docket No. 010031-EI, In Re: 2000 Fossil Dismantlement Cost Study by Florida Power Corporation. We have reviewed PEF's proposed reserve transfers and, consistent with our precedent, believe they are reasonable. Accordingly, we hereby approve the reserve allocations presented in the table below. These reserve allocations are to correct plant-specific dismantlement reserve imbalances based on current dismantlement cost estimates.

Table 7: Theoretical Reserve Reallocations as of January 1, 2010

Plant	Accumulated Reserve as of December 31, 2009	Theoretical Future Dollars to Dismantle	Reserve Transfers	Restated Reserve as of January 1, 2010
	($)	($)	($)	($)
Avon Park Gas Turbine	$5,410,811	-	($5,410,811)	$0
Higgins	$10,158,455	-	($10,158,455)	$0
Inglis Steam	$88,472	-	($88,472)	$0
Port St. Joe Gas Turbine	$599,283	-	($599,283)	$0
Turner Steam	$6,693,907	-	($6,693,907)	$0
Bartow Steam	$21,137,835	$30,260,118	$9,122,283	$30,260,118
Suwannee - Steam Units	$10,512,957	$17,327,448	$6,814,491	$16,461,076
Bartow-Anclote Pipeline	$3,397,041	$15,424,962	$599,283	$6,865,925
Crystal River Units 1 & 2	$25,916,397	$43,332,297	$6,414,872	$34,665,555
Total*	$83,915,158	$106,344,825	$0	$83,915,158
* May not add to total due to rounding				

C. Annual Provision for Dismantlement

Based on its updated fossil dismantlement study, the Company alleged that the total base cost to dismantle its fossil plants increased to $294 million. After applying salvage credits for scrap steel and copper, the Company estimated the net cost to dismantle its fossil plants to be approximately $161 million. PEF proposed a levelized annual accrual for 2010-2014 of $3,845,221 (system).

OPC witness Pous did not recommend any specific adjustments to PEF's fossil dismantlement study. However, witness Pous asserted that if we do decide to address fossil dismantlement in this proceeding, then we should reduce PEF's dismantlement costs by 60 percent.

OPC witness Pous discussed a number of factors that he believes result in excessive demolition cost estimates. First, witness Pous objected to the Company's use of a 20 percent cost contingency factor. Second, witness Pous asserted that the Company dismantlement assumptions are based on "reverse construction," and this demolition approach is a "high side" estimate. Witness Pous further asserted that if a reverse construction demolition approach is employed, a negative contingency factor may be warranted.

Witness Pous argued that PEF has erroneously calculated its expected labor costs. In its responses to OPC discovery, PEF claimed it utilized an average of the local union labor rate and the RS Means Heavy Construction Cost Data 22nd Annual Edition. Witness Pous's analysis shows that only the local union labor rate was utilized.

In response to the labor rate issue addressed by OPC witness Pous, PEF witness Kopp asserts that while there was no error in the calculation of the labor rate, there was an error in its discovery responses to OPC. Witness Kopp confirms that the labor rates included in PEF's 2008 fossil dismantlement study are the local union labor rates only.

PEF witness Kopp believes PEF's requested contingency factor is appropriate irrespective of how OPC witness Pous characterizes such an estimate. Witness Kopp stated that applying a contingency factor to dismantlement cost estimates is a standard industry approach, accounting for issues such as weather delays, which would not be accounted for in a base cost estimate. Witness Kopp believes the Company's approach is consistent with Rule 25-6.04364(2)(a), F.A.C., which permits contingency costs to be included in fossil dismantlement cost estimates for "unforeseeable elements of cost within the defined project scope."

PEF's previous 2004 fossil dismantlement cost study was filed in 2005, but was not placed into effect due to the Stipulation in Order No. PSC-05-0945-S-EI.[29] As stated in the Stipulation approved in paragraph 11 of Order No. PSC-05-0945-S-EI, "PEF will continue to suspend accruals to its reserve for nuclear decommissioning and fossil dismantlement, and shall apply the depreciation rates consistent with those in PEF's Depreciation Study, as modified by Exhibit 2, attached to the Stipulation."

The major factors contributing to the 15 percent decrease in the cost estimate between the current study and the previous study are: (1) the completed dismantlement of two plants; (2) changes in inflation rates; and (3) the change in salvage values.

[29] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

While the 2008 fossil dismantlement study was conducted by Burns and McDonnell, PEF's previous dismantlement studies were conducted by a different engineering firm. As such, there are differences between the current study and prior studies as to the approach employed and certain inputs used. We note two changes between the studies, below.

First, dismantlement studies typically include a contingency factor. A contingency factor is designed to account for unknown expenses at the time the estimate is prepared, but expected to be expended on the project. While the 2008 fossil dismantlement study incorporated a 20 percent contingency factor, the 2004 fossil dismantlement study applied a 15 percent contingency factor.

Second, in the 2008 fossil dismantlement study, Burns and McDonnell applied to the outputs of its analysis an additional 5 percent "project indirects" factor. According to PEF, this factor is designed to recover what are typically contracted demolition costs not included in other cost estimates. In contrast, while it appears that prior PEF dismantlement studies also reflected costs for project indirects, their treatment in these studies differed from the approach in the current study. Accordingly, due to methodological differences between the two studies, we are unable to determine if the relative costs included for project indirects in the two studies are comparable.

The approved dismantlement accruals shown in Table 8 are based on PEF's current cost estimates, escalated to future costs through the time of actual dismantlement. The future costs, less dismantlement reserves recovered to date and subject to reallocation, have been discounted over the remaining life of each plant site/unit. The calculation of the annual accrual for each site is based on the methodology for dismantlement established by Rule 25-6.04364, F.A.C.

Moody's Economy.com[30] publishes inflation factors that are updated on a monthly basis. PEF used Moody's Economy.com to obtain the inflation forecast as well as factors for use in both studies. In the 2008 fossil dismantlement study, the inflation factors PEF used in its original filing were based on the August 2008 issue of Moody's Economy.com. Our staff requested that PEF update its study using the latest available Moody's Economy.com inflation factors, which were from the July 2009 forecast. It was not readily apparent from PEF's updated results that the sizeable increase in the annual accruals were solely attributed to the July 2009 inflation forecast. In addition, the models that were provided contained a rigid design that prevented us from performing the usual sensitivity analyses to test various inflation inputs and contingency factors.

In documentation provided by the Company in response to discovery to update the original filing, the major increases in the updated PEF fossil dismantlement study were attributed to revised scrap metal prices, the revised inflation forecast, and the updated jurisdictional separation factors.

[30] Moody's Economy.com, a division of Moody's Analytics, is a provider of economic, financial, country, and industry research designed to provide information needs of businesses, governments, and professional investors.

The effects of the updated assumptions increased the fossil dismantlement retail annual accrual from \$3.1M to \$8.6M, an increase of approximately \$5.5M (system annual accrual increased from \$3.8M to \$10.0M, an increase of \$6.2M). However, PEF does not seek to establish its annual accrual based on these revised results.

Based on the above, we find that the appropriate system annual provision for dismantlement is \$3,845,221, and the retail annual accrual amount is \$3,113,889. These accruals reflect current estimates of dismantlement costs on a site-specific basis using an August 2008 inflation forecast and a 20 percent contingency factor. The dismantlement accruals are shown in Table 8.

Table 8: Fossil Dismantlement Accrual

PLANT	CURRENT ACCRUAL[31]	COMPANY PROPOSED ACCRUAL	COMPANY PROPOSED CHANGE IN ACCRUAL	APPROVED ACCRUAL	APPROVED CHANGE IN ACCRUAL
	\$	\$	\$	\$	\$
Anclote	-	232,936	232,936	232,936	232,936
Avon Park Gas Turbine	-	3,485	3,485	3,485	3,485
Bartow - Steam	-	0	0	0	0
Bartow - CT	-	7,222	7,222	7,222	7,222
Bartow-Anclote Pipeline	-	574,928	574,928	574,928	574,928
Bartow - CC	-	(7,753)	(7,753)	(7,753)	(7,753)
Bayboro	-	21,329	21,329	21,329	21,329
Crystal River South Units 1 & 2	-	691,265	691,265	691,265	691,265
Crystal River North Units 4 & 5	-	627,398	627,398	627,398	627,398
Crystal River Common	-	411,978	411,978	411,978	411,978
Crystal River Helper	-	176,932	176,932	176,932	176,932
Crystal River Mariculture	-	62,717	62,717	62,717	62,717
Debary Gas Turbine units 1 - 6	-	13,601	13,601	13,601	13,601
Debary Gas Turbine units 7 - 10	-	396,844	396,844	396,844	396,844
Higgins	-	7,077	7,077	7,077	7,077
Hines PB1	-	21,228	21,228	21,228	21,228
Hines PB2	-	17,650	17,650	17,650	17,650
Hines PB3	-	16,643	16,643	16,643	16,643
Hines PB4	-	19,989	19,989	19,989	19,989
Intercession City Units 1 - 6	-	10,363	10,363	10,363	10,363
Intercession City Units 7 -10	-	59,188	59,188	59,188	59,188
Intercession City Units 11	-	12,516	12,516	12,516	12,516
Intercession City Units 12 -14	-	207,479	207,479	207,479	207,479
Port St. Joe	-	0	0	0	0
Rio Pinar	-	6,930	6,930	6,930	6,930
Suwannee - Steam units 1 - 3	-	216,593	216,593	216,593	216,593
Suwannee - CT 1 - 3	-	6,992	6,992	6,992	6,992
Tiger Bay Combined Cycle	-	10,912	10,912	10,912	10,912

[31] The 2004 fossil dismantlement study was filed, but the accrual was set at zero per paragraph 11 of the Stipulation in Order No. PSC-05-0945-S-EI, issued on September 28, 2005, in Docket No. 050078-EI.

PLANT	CURRENT ACCRUAL[31]	COMPANY PROPOSED ACCRUAL	COMPANY PROPOSED CHANGE IN ACCRUAL	APPROVED ACCRUAL	APPROVED CHANGE IN ACCRUAL
Turner Gas Turbine Units 1 - 2	-	711	711	711	711
Turner Gas Turbine Units 3 - 4	-	9,040	9,040	9,040	9,040
Turner - Steam	-	0	0	0	0
University of Florida Gas Turbine	-	9,028	9,028	9,028	9,028
Total Dismantlement Accrual	-	3,845,221	3,845,221	3,845,221	3,845,221

D. Fossil Dismantlement Study

PEF states that the methodology employed for developing costs is essentially the same as that used in the Company's last dismantlement study. PEF states that it made no significant changes to the study's dismantlement assumptions. Changes in the quantity of materials were only made for plants to which physical changes had occurred since PEF's 2004 study. PEF's 2008 study indicates that site remediation includes returning the site to a condition compatible with the surrounding land.

In his testimony, OPC witness Pous objects to two aspects of PEF's fossil dismantlement approach. First, he contends that PEF's dismantlement assumptions "assumed a 100 percent worst case scenario, that being full demolition and site restoration." Witness Pous asserts that PEF is not legally required to restore its plant sites to a "greenfield" condition. Although the OPC witness does not define "greenfield condition" in his testimony, this term typically means that site restoration remediates the land/site suitable for any future use, without restriction, from economic development to recreation. PEF witness Kopp defines restoring to "greenfield" condition as removing all installations above and below ground. However, PEF witness Kopp asserts that PEF's dismantlement study assumes that all underground piping and foundations two feet below grade will remain in place.

Second, witness Pous argues that assuming a "reverse construction" approach is unreasonable. Witness Pous describes "reverse construction" as assuming the Company will dismantle a generating facility piece by piece, including removing foundations and underground piping. Witness Pous recommends that we order PEF to perform detailed analyses of different options and approaches to fossil dismantlement and submit this information with its next fossil dismantlement study. With respect to "reverse construction," PEF witness Kopp argues that a combination of demolition techniques would likely be utilized in order to dismantle a plant, as opposed to completely dismantling a plant "piece by piece."

We note that while OPC witness Pous does not recommend any adjustments to PEF's study, he offers that if we wish to modify PEF's request, we should reduce overall dismantlement costs by 60 percent.

PEF retained the engineering firm Burns and McDonnell to prepare its 2008 fossil dismantlement study. PEF's 2004 fossil dismantlement study was filed in Docket No. 050078-EI, and was conducted by Sargent & Lundy, LLC. Pursuant to the Stipulation approved by this Commission and in accordance with the terms of the stipulation approved in Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In Re: Petition for rate increase by Progress Energy Florida, the 2004 fossil dismantlement study was withdrawn by the Company.

Rule 25-6.04364, F.A.C., is our dismantlement rule. Of particular interest to this issue are subparts 2 (b) and (c):

> (2)(b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the materials and equipment that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or useable condition.
>
> (2)(c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service.

We find that PEF's site restoration assumptions in its 2008 fossil dismantlement study comport with our rule. Accordingly, since they comport to our rule, we find that the site restoration assumptions made by PEF in its 2008 fossil dismantlement study are reasonable. We believe that OPC witness Pous may be suggesting that we should revisit the site restoration provisions of our dismantlement rule. If this is the case, OPC can, at its option, file a petition for this Commission to revisit Rule 25-6.04364, F.A.C.

VI. NUCLEAR DECOMMISSIONING COST STUDY

A. Nuclear Decommissioning Accruals

We hereby find that the issues associated with PEF's nuclear decommissioning study shall be deferred from the rate case and addressed next year when FPL files its nuclear decommissioning study in December 2010. This will afford this Commission the opportunity to address the appropriateness of each companies' cost of nuclear decommissioning at the same time. PEF is not required to prepare a new site-specific nuclear decommissioning study. However, PEF shall update the current study with the most currently available escalation rates.

B. Future Nuclear Decommissioning Costs for Crystal River Unit 3 (CR3)

We hereby find that the issues associated with PEF's nuclear decommissioning study shall be deferred from the rate case and addressed next year when FPL files its nuclear decommissioning study in December 2010. This will afford this Commission the opportunity to address the appropriateness of each companies' cost of nuclear decommissioning at the same time. PEF is not be required to prepare a new site-specific nuclear decommissioning study. However, PEF shall update the current study with the most currently available escalation rates.

VII. RATE BASE

A. Non-utility Activities

OPC witness Dismukes stated that the Company did not assign any general plant and administrative and general expenses to the City of Tallahassee's interest in Crystal River Unit 3 (CR3) plant. Witness Dismukes explained that general plant and administrative and general expenses are common costs which essentially support the Company's entire operations. Witness Dismukes continued by stating that these general plant and general expenses are not dedicated to specific groups of customers and that these costs should be distributed to all customers, including those for which the Company uses a direct assignment methodology. Witness Dismukes recommended that we allocate general plant to the Company's Directly Assigned Wholesale operations using its percentage of directly assigned production, transmission and distribution plant to the total company production, transmission, and distribution plant. Witness Dismukes recommended reducing net plant by $1.8 million based on this methodology. She also recommended reducing retail test year administrative and general expenses by $6.3 million based on the directly assigned percentage of production, transmission, and distribution expenses to the total Company production, transmission and distribution expenses. Finally, witness Dismukes recommended reducing depreciation expense by $68,887 and property tax by $21,433.

PEF witness Slusser did not agree with OPC witness Dismukes' adjustment. He stated that the City of Tallahassee's costs include a share of general plant and administrative and general expenses (A&G) based on the application of a labor ratio to total general plant and A&G. Witness Slusser explained that the City of Tallahassee's responsibility is included through the development and application of a labor ratio. He stated that a labor ratio is a common and recognized basis for allocating general plant and A&G expenses in a cost allocation study. Witness Slusser continued, explaining that the Company's total labor component of O&M assignment for the City of Tallahassee is $701,000 for the test period. He stated that the Company's total labor component of O&M expenses, excluding A&G, is $245,846,000 and that this computes to a percentage ratio of 0.285 percent ($701,000 divided by $245,846,000). He continued, stating that this amount was included with other wholesale business's responsibility that results in a wholesale labor responsibility of 12.309 percent.

PEF witness Slusser testified that the labor allocator is identified as "K627" and is derived on Schedule 12, pages 1 and 2 of the Jurisdictional Separation Study. He stated that the "K627" allocator can be seen as being applied to General Plant on Schedule 2, page 1, line 27, and is applied to A&G expense on Schedule 6, page 2, line 11 of the Jurisdictional Separation Study.

PEF's asserted that according to Exhibit 152, total system A&G expenses are $269,669,716 and by dividing the $269,669,716 by total system energy of 48,574,364 MWH yields a system average A&G cost of $5.55 per MWH. PEF contended that OPC witness Dismukes would assign $6,278,578 of A&G costs to the sale of 102,119 MWH to the City of

Tallahassee, or an average cost of $61.48 per MWH. Finally, PEF stated that the assignment to the City of Tallahassee, on a MWH basis of more than eleven times the system average A&G expense is absurd on its face.

After reviewing the Jurisdictional Separation Study, we agree with PEF witness Slusser that the City of Tallahassee's costs include a share of general plant and A&G costs through the application of a labor ratio developed in PEF's Jurisdictional Separation Study. We believe that, for plant and accumulated depreciation, a better allocator is the one recommended by OPC witness Dismukes with a modification, rather than the labor ratio developed by PEF's Jurisdictional Cost Study. As described above, witness Dismukes allocated general plant to the wholesale operations using the percentage of directly assigned production, transmission, and distribution plant to the total company production, transmission, and distribution plant or .46 percent. Using this methodology for plant results in a reduction to plant of $874,089. As testified by PEF witness Slusser, the Company did make an adjustment to plant of .285 percent which results in a plant allocation to wholesale operations of $1,438,298 on a jurisdictional basis. OPC's recommended adjustment was to reduce plant by $2,312,387 or $874,089 more than the Company allocated to wholesale. Plant shall be reduced by $874,089 based on OPC's direct assignment methodology and after recognizing the amount already allocated by the Company.

OPC recommended increasing accumulated depreciation by $562,236 based on the same .46 percent used to allocate general plant. We would modify the percentage calculation based on the Company's percentage of directly assigned accumulated depreciation for production, transmission, and distribution to total accumulated depreciation for production, transmission, and distribution as shown on MFR Schedule B-6. OPC is in agreement with the modified calculation which results in a percentage of .27 percent rather than the .46 percent used by OPC witness Dismukes. Applying the .27 percent to PEF's Accumulated Depreciation amount results in an adjustment to increase Accumulated Depreciation by $331,304 on a jurisdictional basis. The Company included an adjustment of $349,709 to Accumulated Depreciation in its cost study. Thus, the Company's allocation shall be reduced by $18,405 ($349,709-$331,304). The total reduction to rate base is $892,494 ($874,089+$18,405). As a result of the rate base adjustment, depreciation expense shall be reduced by $26,039 and property tax shall be reduced by $8,300.

We do not agree with OPC's adjustment to reduce A&G expense by $6,278,578 as it appears that the adjustment is too high. While the plant allocation calculated by OPC resulted in a .46 percent of plant being allocated to wholesale operations, OPC's A&G allocation percentage was calculated to be 3.5 percent. We do agree with the Company that, based on an average cost per MWH, OPC's adjustment appears to be unreasonable. We believe that the Company's labor ratio of .285 percent is appropriate when allocating A&G expense to the wholesale operations. Based on the Company's Jurisdictional Separations Study, the Company has $266,959,000 labor related A&G expense. The Company allocated $760,833 ($266,959,000 times .285 percent) of A&G expense on a system basis or $667,783 on a jurisdictional basis related to Tallahassee's interest in CR3. This equates to $6.54 per MWH ($667,783 divided by 102,119 MWH) The $6.54 per MWH that the Company has allocated is more in line with the system average of $5.55 per MWH described above.

Accordingly, we find that plant-in-service shall be reduced by $874,089 and accumulated depreciation shall be reduced by $18,405, a total reduction to rate base of $892,494, based on a direct assignment allocation of general plant with modifications, rather than the labor ratio used by the Company for its wholesale operations allocation. No additional adjustment is necessary for the allocation of A&G expense, as the amount of A&G expense the Company allocates to the wholesale operations is reasonable. Depreciation expense shall be reduced by $26,039 and property tax should be reduced by $8,300 related to the general plant adjustment.

B. Adjustments to Rate Base Related to the Bartow Repowering Project

We hereby find that no adjustments shall be made to rate base related to the Bartow Repowering Project. This stipulation does not prejudice the rights of any intervenor to contest the legality of including the Bartow project in rates during 2009. The new rates resulting from Docket No. 090079-EI, which will reflect the rate base and revenue requirement impact of the Bartow project, will supersede the rate change resulting from Order No. PSC-09-0415-PAA-EI as of the effective date of the new rates.

C. Adjustments related to "The American Recovery and Reinvestment Act"

We hereby find that no adjustment shall be made to reflect any test year or post test year revenue requirement impacts of "The American Recovery and Reinvestment Act" signed into law by the President on February 17, 2009.

D. Level of Plant in Service

We find that the appropriate 13-month average of plant in service for the 2010 projected test year is $10,383,946,687, as reflected in Schedule 1 attached hereto.

E. Accumulated Depreciation

We calculated composite depreciation rates for each of the six functional areas of plant. Those rates are based on previous decisions. The composite rates are:

Steam Production	2.3 percent
Nuclear Production	2.3 percent
Other Production	3.1 percent
Transmission	2.2 percent
Distribution	2.9 percent
General	4.9 percent

Using these factors and the monthly plant balances shown on MFR Schedule B-8, we calculated the depreciation expense using the composite rates. Substituting this expense for the Company's accruals shown on MFR Schedule B-9, we recalculated the 13-month average reserve balances. Based on this calculation, we find that accumulated depreciation shall be reduced by $46,549,627 jurisdictional for the 2010 projected test year to reflect the revised depreciation rates, capital recovery schedules, and amortization schedules resulting from PEF's depreciation study.

F. Accumulated Depreciation and Amortization

We hereby find that the appropriate 13-month average amount of Accumulated Depreciation of Electric Plant in Service for the projected test year is $4,390,605,484, as reflected in Schedule 1 attached hereto.

G. Construction Work in Progress – No Allowance for Funds Used During Construction

We hereby find that PEF's requested level of CWIP-No AFUDC in the amount of $151,145,000 for the projected 2010 test year is appropriate.

H. Plant Held for Future Use

We hereby find that PEF's requested level of Plant Held for Future Use in the amount of $25,723,000 for the projected 2010 test year is appropriate.

I. Level of Nuclear Fuel

OPC Witness Schultz recommended an adjustment of $32,766,000 to the nuclear fuel inventory. Witness Schultz pointed out that the 2009 amount was $68,723,000 greater than the 2008 amount and that PEF should have to justify the increase.

Witness Schultz calculated his recommended adjustment by starting with the December 2008 balance and adjusting it by PEF's estimated purchases and amortization amounts for 2009 and 2010. The calculations appear in Exhibit 170, Schedule B-3.

PEF witness Donahue addressed the requested amount in his rebuttal testimony. Witness Donahue testified that PEF's original Schedule F-8 included only natural uranium inventory procurement for 2009, and that PEF inadvertently omitted $38 million in reload batch-specific services for the 2009 refueling. MFR Schedule B-16 reflects the additional 2009 charges. Witness Donahue's Exhibit 219 corrects the calculations in witness Schultz's Exhibit 170. Witness Donahue's calculations differ slightly from those of witness Schultz. Witness Donahue explained that PEF included a June 2010 amortization expense, whereas witness Schultz had not. Witness Donahue explained further that witness Schultz's calculations had employed averaged values for amortization and expenditures rather than PEF's original inputs.

Witness Donahue explained the $68,723,000 increase from 2009 to 2010 in terms of PEF's strategic inventory policy. PEF's target inventory amount is 400,000 kilograms, a minimum of two years forward operation. PEF's nuclear unit has a 24 month refueling cycle, and the proposed policy would protect against supply interruptions and price uncertainty. PEF does not want to have to purchase uranium in the spot market. Further, witness Donahue explained that PEF does not want to have to operate the nuclear unit at reduced capacity. Witness Donahue noted that several utilities have had to make spot market purchases of uranium because of supply interruptions. Witness Donahue made further note of three other factors that influenced PEF's inventory policy: the uranium price increases in 2006 to 2008, the increased number of nuclear power plants worldwide, and potential supply interruptions due to mines closing temporarily or not being ready for production when planned. These observations of recent market conditions are the reasons for PEF's strategic inventory policy and the increase in the nuclear fuel inventory. By having uranium in inventory, PEF may evaluate the most cost-effective purchase at the time the purchase is made. Witness Donahue was questioned as to whether he considered the inventory strategy to be an intrinsic hedge against price fluctuation, and he agreed that it was.

We agree that due to the changes in the nuclear fuel market in recent years, both in the number of nuclear power plants worldwide, and in the potential unavailability of nuclear fuel at the time it is needed, PEF's strategic inventory is sound. Witness Donahue testified that the nuclear unit burns the lowest cost fuel. We note that by guarding against supply interruptions, PEF's strategy is not only a hedge against possible fluctuations in nuclear fuel prices, but a hedge against having to incur the higher costs of other fuels.

Due to the dollar amount corrections noted in witness Donahue's rebuttal testimony and the rationale provided by witness Donahue for maintaining its target inventory level, no adjustment shall be made to PEF's request nuclear fuel inventory amount. Accordingly, we find that PEF's requested level of Nuclear Fuel – No AFUDC (net) in the amount of $126,556,000 for the projected 2010 test year is appropriate.

J. Storm Damage Reserve

On September 18, 2006, the Commission authorized PEF to continue a $6.0 million annual accrual to the storm reserve.[32] PEF was ordered to calculate interest on the after-tax balance of the storm reserve using a 30-day Dealer Commercial Paper rate equivalent to PEF's actual rating as published by the Federal Reserve.

PEF witness Harris presented a Storm Loss Analysis to estimate PEF's expected annual damage from hurricanes affecting its transmission and distribution (T&D) facilities. He explained that the analysis estimates all possible hurricane events and estimates the damage done to the assets at risk. Witness Harris stated that, to make a reliable estimate of the expected annual loss (EAL), he included the most complete and full damage distribution that could be determined using both actual experience and possible damage from simulated hurricanes. He testified that the EAL was based on data from the long term 100-year hurricane hazard record. PEF provided T&D asset portfolio data on a county-by-county basis. The study estimated that PEF's expected annual hurricane damage is $20.2 million, but that $16.4 million of the $20.2 million EAL is assumed to be an annual obligation of the reserve.

[32] Order No. PSC-06-0772-PAA-EI, issued September 18, 2006, in Docket No. 041272-PAA-EI, In re: Petition for approval of storm cost recovery of extraordinary expenditures related to Hurricane Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.

PEF witness Harris tested the Company's current annual accrual level of $6 million, as well as three higher accruals of $16 million, $25 million, and $35 million. He testified that, for each funding case, the initial $133 million reserve balance was considered and he assumed that interest would be credited on positive reserve balances at a rate of 3.45 percent. Witness Harris testified that PEF's choice of an accrual of $16 million represents a balance between costs to PEF's customers and protection from future surcharges due to storm damage that exceeds the reserve level.

PEF witness Toomey stated that, based on the results of an updated Storm Loss and Reserve Solvency Study (Study), PEF included an increase in the annual accrual to its Storm Damage Reserve to $16 million on a system basis, or $10 million more that the $6 million accrual approved by the Commission in Order No. PSC-94-0852-FOF-EI, issued on July 13, 1994, Docket No. 940621-EI. Mr. Toomey states that the $16 million accrual is equivalent to the expected, average recoverable annual storm loss based on the study. PEF witness Toomey also proposed to include the storm damage reserve in rate base and to discontinue the practice of accruing interest on the reserve balance, which would result in a reduction to rate base.

OPC witness Schultz recommended that the Company's accrual should be reduced to zero because the reserve is sufficient at this time to cover storm costs that are likely to occur based on recent history. He explained that charging the most recent three year average of $6.590 million against the reserve, without any additional accrual, results in a December 31, 2010 reserve balance of $128,651,299 and that, based on the Study, the probability that storm costs in a single year would eclipse the reserve is approximately 3.4 percent. Witness Schultz stated that his recommendation reduced O&M expense $14.922 million and increased working capital and rate base $27.160 million.

FIPUG witness Marz testified that PEF has not supported a $10 million increase. He continued, stating that since the current $133 million storm reserve is sufficient to cover all but the most severe storms, all contributions to the storm reserve should cease. Witness Marz stated that over the last three years PEF has charged less than $13 million (in total) to the reserve and that this equates to a three-year average of $4.3 million. He testified that, according to PEF's Study, there is a 3.3 percent probability that there will be damage in any one year that exceeds the current reserve level of $133 million. In other words, a storm inflicting damage in an amount of approximately $130 million is likely to occur once every 33 years. He explains that the storm reserve and associated accrual are only part of the framework for recovering storm restoration costs.

In response to OPC witness Schultz excluding the 2004 storms, PEF witness Harris stated that, excluding any possible damage events, whether large and infrequent or small and frequent, is neither meaningful nor appropriate. In rebuttal to witness Schultz and witness Marz's recommendations to cease accruals, witness Harris testified that the concept of self-insurance using a reserve with accruals is to allow the accumulation of funds during periods of favorable storm experience that will be available for infrequent future hurricane losses. He continued, stating PEF estimates that the value of its T&D assets has increased by more than a factor of three since 1993, when the accrual was approved by the Commission. Further, a higher accrual is appropriate to reflect the current increased value of its T&D assets.

FRF stated, in its brief, that we should order PEF to reduce its storm accrual to zero, because the current reserve balance is sufficient to cover the costs of non-catastrophic storms and the Company has available other means of addressing cost recovery in the event of catastrophic storms.

PEF witness Harris was asked if the storm experience for 2005, 2006, 2007, 2008, and to date for 2009 was factored into his study, would the study produce any different results. He responded that the study did in fact include 2006 and 2007, which had no storms. He continued, stating that 2008 and 2009 have not been included in the study, and the 2008 data of no storms would in fact reduce to some very small extent the hazard. Witness Harris also stated that storm hardening impacts were not taken into consideration in the study and that it's generally understood that the activities for storm hardening will, in fact, reduce damage and restoration times.

OPC witness Schultz and FIPUG witness Marz both recommended that the requested $10 million increase in the storm accrual be denied and that the current accrual cease. Witness Marz stated that we have demonstrated our ability and willingness to promptly consider and act upon a utility's request to recover storm costs. As such, the storm reserve need not cover all storms and to do so would impose an unnecessary added burden on ratepayers.

Based on PEF's supplemental Schedule B-21, filed March 27, 2009, the Storm Damage reserve is projected to be $151,646,000 at December 31, 2009. This amount does not include charges for Tropical Storm Fay (2008) of $9,869,872, which would reduce the reserve to $141,776,128 at the end of 2009. It appears likely, at this point in time, that there will be no substantial charges to the storm reserve for 2009. According to witness Harris's study, there is a 3 percent chance of having storm damages greater than $140 million in any given year and a 2.7 percent chance of having storm damages greater than $150 in any given year.

PEF's Study shows that the expected value of the reserve in 5 years will be $99 million with a 14 percent probability of the reserve being less than $0 based on the Study's expected annual loss of $16.4 million and an annual accrual of $6 million. Increasing the annual accrual to $16 million from $6 million reduces the probability of the reserve going negative by only 4 percent (from 14 percent to 10 percent). While a category 4 storm could result in damage of over $500 million, the study shows that the probability of that occurring in any year is less than 1 percent. The Company included $159,106,000 as a deduction to working capital and therefore rate base in its filing, based on its proposed annual accrual of $14,922,000 ($16 million system) for 2010.

Accordingly, we find that PEF's requested increase to its storm damage accrual is hereby denied and the current $5.566 million accrual ($6 million system) shall be reduced to 0. This results in an increase to jurisdictional working capital of $17,329,872 and a storm reserve of $141,776,128 for the projected 2010 test year. The Company's jurisdictional O&M expense is hereby reduced by $14,922,000 ($16 million system) for the 2010 test year. We further find that the Company shall discontinue the practice of accruing interest on the storm reserve balance and instead include the reserve amount as a deduction to rate base.

Our decision herein is based on our belief that the current storm damage reserve is sufficient at this time. The Company has the option of petitioning this Commission for a surcharge to recover the storm damage costs not recovered through the storm damage reserve. As demonstrated in the past, we have allowed companies to recover extraordinary hurricane losses, such as the ones experienced by PEF in 2004, through a separate surcharge.

K. Fuel Inventories

We find that no adjustment shall be made to PEF's requested level of non-nuclear fuel inventories in the amount of $347,235,000 (system). The appropriate jurisdictional amount is discussed later in the order.

L. Unamortized Rate Case Expense

PEF included $2,787,000 of unamortized rate case expense in working capital for 2010. PEF revised, in its brief, the amount of unamortized rate case expense to be included in working capital to $1,688,000.

OPC witness Schultz stated that the Company requested the full amount of unamortized rate case expense be included in rate base without factoring in amortization in the rate year and ignoring the fact that rate base is an average not a beginning of the year amount. He stated that allowing the Company's proposed treatment would result in a double charge to ratepayers and ignore the fact that amortization in the rate year occurred. Witness Schultz recommended an adjustment to reduce the Company's requested amount by $969,531 which resulted an unamortized rate case expense amount to be included in rate base of $1,817,469. On cross examination, witness Schultz agreed that it would also be appropriate to exclude rate case expense from working capital altogether.

We have a long-standing policy in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases.[33] The rationale for this position was that ratepayers and shareholders should share the cost of a rate case; i.e., the cost of the rate case would be included in the O&M expenses, but the unamortized portion would be removed from working capital. It espouses the belief that customers should not be required to pay a return on funds expended to increase their rates.

While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital. The difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period (Section 367.0816, F.S.). While unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends.

[33] Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In re: Application of Gulf Power Company for a rate increase; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. PSC-09-0375-PAA-GU, In re: Petition for rate increase by Florida Public Utilities Company.

We agree with the long-standing policy that the cost of the rate case should be shared, and therefore find that the unamortized rate case expense amount of $2,787,000 shall be removed from working capital.

M. SFAS 143 (Asset Retirement Obligations)

OPC witness Schultz stated that the Company increased the working capital requirement by $446,569,000 and reduced plant in service $48,532,000 for a total net increase to rate base of $398,038,000 related to the Company's Asset Retirement Obligations (ARO). He explained that Rule 25-14.014, F.A.C., Accounting for Asset Retirement Obligations Under SFAS 143, states that the implementation of the accounting treatment shall be revenue neutral in the rate making process. Witness Shultz expressed concern that he could not find any detailed explanation in testimony or in the filing that would explain this adjustment. He testified that the entry made by the Company in this docket removes the liability from working capital and does not have an equivalent entry made to plant, accumulated depreciation and/or the deferred assets included in working capital. Witness Schultz did not recommend an adjustment in his direct testimony, but proposed to defer any determination to allow the Company to provide justification for the adjustment. In its brief, OPC recommends that we require PEF to record a system adjustment of $398,038,000 (reduction) to rate base to offset the increase in working capital caused by the ARO adjustment.

PEF, in its brief, stated that the adjustments that OPC witness Schultz references, were made simply to remove from rate base the cumulative effect of the entries for SFAS 143, as required by rule. PEF's brief states that what witness Schultz fails to recognize is that this adjustment has been made to remove the effects of FAS 143 per the requirements of Rule 25-14.014, F.A.C., because the account balances related to FAS 143 are included as a net reduction to the system per books numbers on MFR B-1. The brief continued, explaining that the net ARO liability that is adjusted out of rate base is a funded liability and that the offsetting assets for this liability are the accounts for the nuclear decommissioning trust fund located in the Other Special Funds adjustment in MFR Schedule B-1, as explained in PEF's response to Staff's Twenty-Seventh Set of Interrogatories, No. 323.

We have reviewed the ARO adjustments made to working capital as shown in MFR Schedules B-1 and B-17 and would agree with the Company that the ARO adjustments are in compliance with Rule 25-14.014, F.A.C. Rule 25-14.014, F.A.C., states that SFAS applies to legal obligations associated with the retirement of tangible, long-lived assets that result from the acquisition, construction, development or normal operation of a long-lived asset. For utilities required to implement SFAS 143, it shall be implemented in a manner such that the assets, liabilities and expenses created by SFAS 143 and the application of SFAS 143 shall be revenue neutral in the rate making process. According to PEF's Working Capital MFR B-17, Account 230, Asset Retirement Obligations, in the amount of $376,877,000, was included in the system per books amount shown on B-1; additional amounts across various accounts totaling $69,692,000 related to SFAS 143 were also shown on B-17. The total of these two amounts is $446,569,000 which is shown on MFR Schedule B-1, line 3, column H. There is also a net plant adjustment of a negative $48,532,000, shown on line 3 of MFR Schedule B-1, related to the

ARO adjustment. Combining these two amounts results in the total rate base adjustment of $398,038,000 ($446,569,000- $48,532,000) shown on MFR Schedule B-1, page 1, column J.

According to a Company response to discovery, MFR Schedule B-1, page 1 of 3, line 13, an adjustment to Other Special Funds, in the amount of a negative $446,428,000, contains the offsetting working capital liability accounts that correspond with the asset working capital accounts. As evidenced by the Company's MFR adjustments, we agree that the impact of SFAS 143 has been removed in a revenue neutral manner.

Accordingly, we find that the Company has properly accounted for the impact of SFAS 143 in its working capital calculation and therefore no adjustment to rate base for this item is required.

N. Working Capital Allowance

We find that the appropriate 13-month average for working capital for the 2010 projected test year is $5,502,872, as reflected in Schedule 1 attached hereto.

O. Level of Rate Base

We find that the appropriate 13-month average rate base for the 2010 projected test year is $6,302,278,075, as reflected in Schedule 1 attached hereto.

VIII. COST OF CAPITAL

A. Accumulated Deferred Income Taxes

According to PEF, the Company recorded a balance of jurisdictional accumulated deferred income taxes (ADITs) to include in its capital structure of $389,229,000. This is a reduction of $68,000 from PEF's original filing of $389,297,000. Deferred income taxes are a component of the capital structure that are a result of timing differences between depreciation used for calculating federal income tax liabilities and actual book depreciation for utility property or plant.

OPC and FIPUG asserted that the correct amount of ADITs is $373,161,000. They did not sponsor any specific testimony or propose any specific adjustment. FRF asserted that the correct amount of ADITs is $329,399,000. FRF did not sponsor any specific testimony or propose any specific adjustment to the balance of ADITs.

The correct amount of ADITs is a result of various adjustments. Adjustments to net operating income, depreciation, rate base, etc. all affect the amount of ADITs. Based on adjustments to various capital structure and rate base items discussed elsewhere in this order, the net effect is an increase in the balance of ADITs. Therefore, we find that the appropriate amount of accumulated deferred taxes to include in PEF's capital structure is $420,124,731, as shown on Schedule 2, attached hereto.

B. Unamortized Investment Tax Credits

The Company included $3,609,000 of unamortized investment tax credits (ITCs) in its capital structure at a cost rate of 9.74 percent. The Company recognized that the balance of ITCs has changed from its original filing as a result of changes made to the jurisdictional rate base.

OPC and FIPUG proposed an ITC balance of $4,991,000, with a cost rate of 7.84 percent. OPC acknowledged that "this issue is dependent upon the final determination of the cost of Common Equity and the capital structure proportions recommended by the Commission." OPC's position is based on the capital structure and ROE recommended by witness Woolridge. There was no specific testimony regarding the ITCs.

We believe that PEF's methodology for calculating the balance of ITCs is appropriate and is in accordance with IRS requirements. However, due to adjustments to various capital structure and rate base items discussed elsewhere in this order, the net effect is an increase in the balance of ITCs.

In addition, we do not agree with the Company's proposed cost rate of 9.74 percent. This rate is based on a number of adjustments and the cost rates of investor sources of capital; thus, we recalculated the ITC cost rate based on other adjustments and the return on equity, resulting in an 8.36 percent cost rate for ITCs. Accordingly, we find that the appropriate amount and cost rate of unamortized ITCs to include in PEF's capital structure are $3,896,358 and 8.36 percent, respectively, as shown on Schedule 2, attached hereto.

C. Pro Forma Adjustment

PEF witness Sullivan testified that all three rating agencies consider off-balance sheet obligations such as purchased power agreements (PPAs) when assessing a company's credit quality. While he acknowledged that each of the rating agencies employs different methodologies for the treatment of PPAs, witness Sullivan stressed that each rating agency considers PPAs when assessing PEF's credit quality. For this reason, he testified that the weighted average cost of capital approved for purposes of this proceeding must recognize on a pro forma basis the amount of equity necessary to offset the effect of the imputed debt associated with long-term PPAs.

Based upon the methodology employed by Standard & Poors' (S&P), witness Sullivan testified that PEF would need approximately $711 million of additional equity in its capital structure to maintain a 50 percent equity ratio after the recognition of imputed debt associated with its long-term PPAs. He noted that the 2005 Stipulation approved by this Commission in Order No. PSC-05-0945-S-EI included a pro forma adjustment to PEF's capital structure for ratemaking purposes to account for S&P's methodology related to the treatment of PPAs.[34] Witness Sullivan further testified that "an unfavorable outcome in PEF's current base rate

[34] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc., p. 3.

proceeding, including a reversal of the favorable treatment of long-term PPAs in the Company's capital structure under its existing rate case stipulation and settlement agreement approved by this Commission in Order No. PSC-05-0945-S-EI, would have a negative impact on PEF's credit profile and could result in a downgrade."

OPC witness Woolridge testified that, given our specific clause recovery mechanism for PPA payments, the financial condition of an electric company is not impaired by entering into these contracts. He based his opinion on the following passage from a March 2005 Moody's Investors Service (Moody's) report:

> If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

In addition, witness Woolridge testified that even if S&P did impute debt associated with PPAs, such an adjustment is not consistent with GAAP accounting and will not show up in the balance sheet the Company files with the Securities and Exchange Commission (SEC). For these reasons, witness Woolridge argued that "providing incremental revenues through a higher equity ratio and a higher overall rate of return is unnecessary and would result in an unwarranted revenue benefit to the utility."

FIPUG witness Pollock also testified that it is unnecessary to impute equity for PPA obligations. He noted that, once approved, PEF is allowed full and direct recovery of firm energy and purchased power capacity costs under the fuel and capacity cost recovery clauses. Moreover, because such contracts are reviewed in annual cost recovery proceedings, witness Pollock testified there is minimal recovery risk associated with PPAs.

Witness Pollock testified that, due to the cost recovery mechanisms available to PEF for the recovery of costs associated with PPAs, he believes it is unlikely Moody's would make an imputed debt adjustment applicable to these contracts. He also referenced language from a May 2007 S&P report that explained how its methodology for the treatment of PPAs is for the rating agency's own analytical purposes. Specifically, S&P stated:

> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect the fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

Finally, witness Pollock noted that we recently rejected a similar proposal by Tampa Electric Company (TECO) to recognize imputed equity in its capital structure in Order No. PSC-09-0283-FOF-EI.[35] For these reasons, he recommended that we exclude PEF's imputed equity adjustment from its capital structure for purposes of setting rates in this proceeding.

PEF included a $711 million pro forma adjustment to equity in its projected 2010 capital structure for purposes of setting rates in this proceeding. This adjustment has the effect of increasing PEF's equity ratio as a percentage of investor capital from 50.3 percent to 53.9 percent. The annual revenue requirement impact of this adjustment is $24.7 million.

The pro forma adjustment to equity proposed by PEF is not an actual equity investment in the utility. It is a ratemaking adjustment. If this adjustment is approved for purposes of setting rates in this proceeding, the Company would essentially be allowed to earn a risk-adjusted equity return on an incremental equity investment that was never made.

PEF witness Sullivan acknowledged that, given the cost recovery mechanism in Florida and the fact that PEF has never been denied recovery of PPA costs, there is a very low risk of non-recovery of PPA costs. He also agreed that Moody's does not make an explicit adjustment for PPAs like S&P does and that there is no guarantee PEF's bond rating would be upgraded by any rating agency if this pro forma adjustment were approved for rate setting purposes. Witness Sullivan acknowledged that the proposed pro forma adjustment is not consistent with GAAP accounting. He also agreed that the Commission recently denied a request by TECO for a similar adjustment in its rate case. Finally, witness Sullivan agreed that, while the 2005 Stipulation included a pro forma adjustment to PEF's capital structure for ratemaking purposes to account for S&P's methodology related to the treatment of PPAs, said approval did not constitute binding precedent in any future proceeding.

Based on the record evidence and for the reasons discussed above, we find that PEF's requested pro forma adjustment to equity shall be denied for purposes of setting rates in this proceeding. Thus, the $711 million (system) adjustment shall be removed from the capital structure through a specific adjustment to common equity on a system basis.

D. Equity Ratio

PEF witness Sullivan testified that PEF needs a solid investment grade rating in order to provide the Company with access to low-cost debt under all capital market conditions. PEF is currently rated triple B plus by S&P, single A3 by Moody's, and single A flat by Fitch Ratings (Fitch). Witness Sullivan testified that the Company is targeting a mid-single A rating from each of the three rating agencies.

Witness Sullivan testified that utilities with stronger bond ratings, such as the mid-single A rating targeted by PEF, can expect to pay a lower premium on its debt and equity than utilities with weaker bond ratings. He stated that achievement and maintenance of a mid-single A rating

[35] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 36.

requires a capital structure and other credit metrics that are supportive of this rating. Witness Sullivan also cautioned that both S&P and Moody's have indicated in recent reports that a lack of improvement in PEF's credit metrics could result in ratings being lowered.

Witness Sullivan testified that the importance of financial strength is even more pronounced for utilities pursuing new nuclear generation. He stated that rating agencies as well as equity investors expect utilities with plans for nuclear development or other large generation projects to maintain strong ratings to offset the perceived risks associated with such projects. Given PEF's significant capital expenditure program, he stated that PEF needs to strengthen its financial profile in the near term so the Company has sufficient access to both the short-term and long-term capital markets at a reasonable cost.

Witness Sullivan challenged the reasonableness of the intervenors' recommendations regarding the appropriate equity ratio for PEF. He testified that OPC witness Woolridge's and FIPUG witness Pollock's recommended adjustments would negatively impact PEF's ability to maintain and improve its financial strength. Moreover, witness Sullivan argued that if the intervenors' recommended adjustments to cash flow, return on equity, and capital structure were adopted, "the change in the tone of the Florida regulatory environment and the resulting implications on the Company's cash flow and credit metrics would likely result in a credit rating downgrade." PEF witness Dolan further added that "denying some or all of PEF's rate request will affect the Company's financial strength and potentially have an adverse impact on the timing and ultimate construction of the Levy Nuclear Project."

OPC witness Woolridge testified that PEF's proposed equity ratio of 53.9 percent as a percentage of investor capital is not appropriate for purposes of this proceeding because it is not based on Company book figures due to a number of adjustments, most notably imputed equity; it does not reflect the actual capitalization of PEF or Progress Energy, Inc. (Progress Energy); and it does not reflect the capitalization of other electric utilities.

Witness Woolridge recommended an equity ratio of 50.0 percent as a percentage of investor capital. He arrived at his recommended level of equity capitalization by averaging the Company's projected 2009 and 2010 equity capitalizations. He stated that his recommended equity ratio is higher than the average equity ratio for the companies in his electric utility proxy group and therefore represents a lower financial risk than his group of comparable companies. By eliminating the proposed pro forma adjustment to equity, witness Woolridge testified that his recommended equity ratio is a more realistic view of the expected equity capitalization of the Company as viewed by investors.

FIPUG witness Pollock testified that PEF's equity ratio of 50.3 percent (excluding the imputed equity adjustment for PPAs) should be used for purposes of determining the cost of capital in this proceeding. He noted that a 50 percent equity ratio is higher than the industry average. For the period 2006 through the first quarter of 2009, the average equity ratio for all electric utilities followed by SNL Financial ranged from 46.1 percent to 47.6 percent. He concluded that an "adjusted 2010 test year common equity ratio of 50.3 percent would be well above the average" equity ratio of other electric utilities.

Witness Pollock also addressed the issue of whether a 50 percent equity ratio would be sufficient to maintain PEF's current bond ratings. He testified that the average equity ratio for A-rated electric utilities over the period 2006 through the first quarter of 2009 varied from a low of 49.5 percent to a high of 51.0 percent and averaged 50.2 percent over the entire period. Based on this analysis, he stated that PEF's equity ratio of 50.3 percent (without including an adjustment for PPAs) is consistent with comparable A-rated electric utilities. For these reasons, witness Pollock recommended that we recognize an equity ratio of 50.3 percent as a percentage of investor capital and 46.9 percent as a percentage of total capital for purposes of this proceeding.

The projected 2010 capital structure PEF has proposed for purposes of setting rates in this proceeding reflects an equity ratio as a percentage of investor capital of 53.9 percent. Excluding the $711 million pro forma adjustment to equity, the capital structure reflects an equity ratio of 50.3 percent. The equity ratio at year-end 2008 was 42.2 percent.

Witness Sullivan testified that the Company's proposed equity ratio is necessary to generate credit metrics commensurate with a bond rating in the mid-single A range. However, there are a number of factors used to determine a company's bond rating, not just its capital structure. Even if we were to approve PEF's petition and grant the full amount of its requested rate increase, there is no guarantee that S&P would upgrade PEF's credit rating from triple B to single A.

Witness Sullivan acknowledged that Company management makes the decisions that affect the relative balance of debt and equity maintained in PEF's capital structure. He also agreed that management's decisions regarding the relative capitalization of PEF impact the Company's bond rating. S&P employs a consolidated rating methodology whereby it generally assigns a rating to each entity in an organization based upon the credit profile of the consolidated entity. Witness Sullivan agreed that the reason S&P assigns a lower rating to PEF than the ratings assigned by Moody's and Fitch is due to the consolidated rating methodology that considers the credit profile of Progress Energy, not just the credit profile of PEF on a stand-alone basis. Moreover, witness Sullivan agreed that S&P would not upgrade PEF's rating until the credit metrics of both PEF and Progress Energy improved to the level necessary to support the stronger rating.

Prior to the acquisition of Florida Progress Corporation by Carolina Power & Light Company (CPL), PEF was referred to as Florida Power Corporation (FPC). At that time, FPC was rated double A minus by S&P and double A3 by Moody's. After the acquisition was announced, Moody's placed FPC's ratings on review for possible downgrade. In its August 23, 1999 report, Moody's stated:

> Concern for ratings pressure from acquisition financing drives the review for downgrade of FPC securities and the negative outlook for CPL's ratings. While the two entities are roughly equal in size, Moody's is concerned FPC, the higher-rated and therefore more liquid entity, may come under relatively greater pressure to service acquisition leverage.

On November 20, 2000, S&P downgraded FPC's rating from double A minus to triple B plus. In the report that announced the downgrade, S&P stated:

> The rating actions are in anticipation of the imminent completion of the previously announced agreement by Carolina Power & Light Company to purchase Florida Progress and its affiliates in a stock-and-cash transaction, valued at $5.3 billion. The transaction will require a substantial amount of debt financing (approximately $3.5 billion) initially funded through commercial paper at the CPL energy level.

While its rating was further downgraded to triple B flat in August 2003 and later upgraded back to triple B plus in March 2007, PEF's rating from S&P never recovered to its preacquisition rating, or even a single A rating, principally due to the pressure to service significant debt leverage at the parent level.

From 1999 through 2003, FPC/PEF generated net income of $1.4 billion. Approximately 23 percent of this amount was invested in the utility and the remaining 77 percent was retained by the parent company. Equity infusions from the parent to the utility totaled $71 million over this period. From 1999 through 2003, FPC/PEF's equity ratio varied from a low of 47.7 percent to a high of 54.7 percent and averaged 51.8 percent over the period.

From 2004 through 2008, PEF generated net income of $1.6 billion. Approximately 76 percent of this amount was invested in the utility and the remaining 24 percent was retained by the parent company. There were no equity infusions from the parent to the utility over this period. From 2004 through 2008, PEF's equity ratio varied from a low of 42.2 percent to a high of 50.5 percent and averaged 47.5 percent over the period.

For the 10-year period 1999 – 2008, PEF's equity ratio averaged 49.7 percent. However, by year-end 2008 PEF's equity ratio was 42.2 percent. To achieve an equity ratio of 53.9 percent for purposes of the 2010 projected capital structure, PEF assumed it would pay no dividend to Progress Energy in 2009, would receive an equity infusion from Progress Energy totaling $640 million in 2009, and would have $711 million of imputed equity recognized in its 2010 capital structure.

We do not agree with the arguments advanced by Company witnesses that we must set rates in this proceeding to generate revenue sufficient to achieve financial metrics in a particular rating range. We have a long history of constructive regulatory decisions that provide for the timely recovery of prudently incurred expenses and capital investments to support the financial integrity of companies under our jurisdiction. If a company believes a particular debt rating is optimal, it is the parent company's responsibility to manage the flow of funds between itself and its operating companies. This includes making equity infusions in the utility sufficient to achieve financial metrics in that rating range consistently over time, not just during the test year.

In addition to the fact that there is no guarantee that PEF's rating from S&P would be upgraded to single A even if it received the full rate increase it requested in this proceeding, it is unrealistic to expect S&P to upgrade PEF until the financial metrics at the consolidated level also improve. The level of equity recognized for purposes of setting rates should be in line with the risk associated with the provision of regulated operations. There is no mandate from S&P or any of the other rating agencies that this Commission or any other regulatory commission allow an inflated equity ratio at the utility level to compensate for the parent company's use of higher debt leverage. Our statutory responsibility is to set a rate of return for this Company commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to attract capital under reasonable terms. This responsibility does not extend to setting a rate of return to generate cash flow sufficient to improve the debt rating of the parent company.

As for the testimony that rating agencies and equity investors expect utilities with plans for new nuclear projects to have stronger credit ratings to offset the perceived risks associated with such projects, we are in agreement. Florida has a progressive recovery mechanism in place for the timely recovery of prudently incurred costs associated with new nuclear development. The nuclear cost recovery statute passed by the Florida Legislature in 2006 effectively shifted risk from a company's shareholders to its customers to help mitigate the perceived risk associated with new nuclear construction. In addition, Moody's has commented on the various means available to companies pursuing new nuclear generation to defend existing ratings or to limit negative rating actions. It was the Company's decision to pursue a nuclear project that is significantly greater than the value of its existing rate base. Now having made this election, it is the responsibility of management and the Board of Directors of PEF to actively pursue financial policies that will permit the utility to strengthen it financial metrics as well as improve the financial metrics at the consolidated level necessary to support a higher rating. In a June 19, 2009, report regarding PEF, Moody's stated that:

> An upgrade is unlikely while the utility has a major rate case pending and is undertaking a major new nuclear construction project. An upgrade could be considered, however, if there are significant mitigants to offset the risks inherent in such a large and complex nuclear construction project, including preapproval of recovery for nuclear capital expenditures, the sharing of risk with contractors or other parties, and the inclusion of co-owners or other partners. An upgrade could also be considered if there is a recovery of cash flow coverage metrics from currently low levels, including a ratio of CFO before working capital plus interest to interest above 5.0x and CFO before working capital to debt above 25 percent. The rating is somewhat constrained by the high level of debt at the parent company level.

We will provide for the timely recovery of prudently incurred expenses and capital expenditures. However, as noted earlier, we cannot set rates sufficient to overcome constraints on the utility's bond rating due to a high debt level at the parent company.

Finally, PEF witness Vander Weide identified a group of companies that he testified face comparable business risk and represent a reasonable proxy for the risk of investing in PEF. The companies in witness Vander Weide's proxy group had an average equity ratio of 47.4 percent in

2007 and 45.7 percent in 2008. While the companies are projected to have equity ratios in 2010 that range from a low of 38.5 percent to a high of 55.5 percent, the average projected equity ratio for the group is 46.6 percent.

Accordingly, we hereby approve the capital structure shown on Schedule 2, attached hereto. This capital structure reflects the Company's proposed capital structure for 2010 with a specific adjustment to remove the $711 million of imputed equity previously discussed. This capital structure reflects an equity ratio of 50.3 percent as a percentage of investor capital. This equity ratio reflects the projected $640 million equity infusion from Progress Energy. As of June 2009, nearly half or $310 million of this amount has actually been invested in the utility. While this relative level of equity is within the range of projected equity ratios of the companies in witness Vander Weide's proxy group, it is above the average equity ratio for the group. In addition, although this level of equity is below the equity ratio requested by PEF, it is higher than the actual equity ratio the Company has maintained on average over the past decade. This equity ratio is supported by competent and substantial evidence in the record.

E. Reconciliation of Rate Base and Capital Structure

The purpose of this issue is to determine if rate base and capital structure have been appropriately reconciled. None of the intervenors took a position on this nor did any intervenor proffer any testimony or file a post-hearing brief regarding the appropriate method to reconcile rate base to capital structure. The appropriateness of those adjustments centers on whether certain pro rata adjustments should be reconciled over all sources of capital or over investor sources of capital only. PEF stated that the Company reconciled rate base to capital structure by first making specific adjustments where appropriate. PEF made specific adjustments to common equity, short-term debt, and deferred income taxes. For common equity, PEF removed $4,825,000 of non-utility investment consistent with Commission practice. PEF added $711,330,000 to common equity to compensate for off-balance sheet obligations related to PPAs. PEF removed $7,833,000 from short-term debt to convert a variable rate to a daily weighted average balance. For accumulated deferred income taxes (ADITs), PEF added $32,524,000 to reflect ADITs related to nuclear decommissioning and added $127,565,000 to recognize the impact that the recovery of the costs through the Nuclear Cost Recovery Clause has on ADITs. After PEF made these adjustments to specific components in the capital structure, all other adjustments were made pro rata over all sources of capital.

In its response to our Staff's Twenty-Seventh Set of Interrogatories, No. 321, PEF explained how the amount of CWIP removed from the rate base should be removed from the capital structure for the 2010 test year. In its response, PEF stated:

> With the exception of the portion of CWIP generated by the Levy Nuclear project and collected through the clause, PEF believes that the CWIP rate base adjustments should be adjusted from the capital structure on a pro rata basis over all sources of capital. This approach is preferred as the simplest way to assure that ADIT adjustments do not violate tax normalization rules. Under the tax normalization rules, any ratemaking adjustment with respect to a utility's deferred

> tax reserves must be consistently applied with respect to rate base, depreciation expense and income tax expense. The consequence of a normalization violation would be the risk of loss of accelerated tax methods for depreciation. This would represent a loss of substantial benefits to our customers. In addition this approach makes sense in that it matches the way PEF funds rate base and manages it sources of capital.

PEF explained that a significant portion of its pro rata adjustments reflect the removal of clause-related plant and AFUDC eligible CWIP from PEF's retail rate base. PEF removed the clause-related items because they earn their own return outside of base rates through a cost recovery clause. The clause-related plant and AFUDC-eligible CWIP removed from rate base earn a Commission approved rate of return calculated over all sources of capital including accumulated deferred income taxes, customer deposits, and investment tax credits. PEF maintained that one approach to assure the Company does not violate IRS tax normalization rules is to have the calculation of the rate of return for the reconciled jurisdictional rate base match the calculation of the rate of return for clause-related items. PEF stated that this avoids the potential of double counting the benefit of ADITs and customer deposits. PEF explained:

> If PEF were to adjust rate base over only investor sources of capital, when clause assets are removed from jurisdictional rate base, the proportion of deferred taxes and customer deposits that remain in the reconciled, jurisdictional adjusted capital structure used to calculate the base rate required rate of return is increased. The same zero cost deferred taxes and customer deposits that reduced the clause rate of return are used again to lower the base rate required rate of return. This is the double counting effect.

PEF asserted that the same scenario occurs when an adjustment is made to exclude AFUDC-eligible CWIP from rate base. PEF explained that the AFUDC rate that provides a capitalized return on the CWIP balances removed from rate base is calculated over all sources of capital. It is PEF's position that the methodology used to calculate the base rate required rate of return should match the methodology to calculate the rate of return earned on CWIP. PEF explained that if the AFUDC-eligible CWIP balance remaining in the jurisdictional rate base is reconciled over investor sources of capital only, no deferred taxes and customer deposits are removed from the capital structure, thus, a double counting of ADITs and customer deposits would occur again.

In response to our Staff's Twentieth Request For Production Of Documents, No. 107, PEF provided copies of the Internal Revenue Code and IRS income tax regulations regarding the IRS tax normalization rules. During cross examination, PEF witness Toomey was presented with a copy of PEF's response and testified that he was generally familiar with the IRS tax normalization rules. Witness Toomey agreed that the IRS tax normalization rules relate to the treatment of deferred taxes and income tax expense for the purpose of calculating federal income tax liability. Witness Toomey testified that he believed the IRS normalization rules specify requirements related to the reporting of deferred taxes in order to ensure that PEF does not violate normalization. Witness Toomey was asked if the IRS tax normalization rules specify that a regulated utility shall make adjustments to its rate base over all sources of capital as opposed to only investor sources of capital in its capital structure. In reply, witness Toomey stated that he did not know if it does specifically or not. Witness Toomey could not identify anything in the Internal Revenue Code and IRS income tax regulations that would specifically tell PEF exactly how to make the adjustments in its MFRs or reconcile its rate base.

PEF argued that a second reason to reconcile rate base over all sources of capital is that it matches the way PEF funds its rate base and manages its sources of capital. PEF explained that all sources of capital, including customer deposits, deferred taxes, and investment tax credits are pooled together to fund PEF's rate base in the normal course of its operations. PEF stated that its sources of capital cannot be traced solely to investor-supplied sources of capital and that it does not segregate its sources of capital. PEF explained that such adjustments would be appropriate only if PEF were financing the clause-related plant and CWIP that is excluded from rate base differently than it is financing the plant and CWIP included in the recoverable base rate.

PEF believes that to avoid a potential violation of IRS tax normalization rules, the rate of return for clause-related plant and AFUDC-eligible CWIP removed from the rate base should be calculated using the same methodology as the rate of return for the jurisdictional rate base so that adjustments to ADITs are applied consistently. PEF has reconciled rate base to capital structure over all sources of capital. We believe that the appropriate method to reconcile rate base to capital structure is to make adjustments to the class of capital in the capital structure that correspond to adjustments made to related accounts in rate base. For example, adjustments made to rate base from accounts that do not generate deferred taxes or investment tax credits should not be reconciled over deferred taxes or investment tax credits in the capital structure. However, we recognize that the record does not contain testimony and evidence supporting this methodology. The record shows that PEF does not segregate its sources of capital and track its funding usage. Accordingly, for the sole purpose of setting rates in this rate case only, we find that rate base and capital structure have been reconciled appropriately.

F. Capital Structure

This issue addresses the appropriate capital structure for ratemaking purposes for the projected 2010 test year. As discussed earlier, based on previous decisions we have approved adjustments to the balances of common equity, ADITs, and ITCs. In addition to these adjustments, it was noted that PEF applied a jurisdictional factor of 75.95 percent to customer deposits included in its proposed capital structure for the 2010 test year. The application of a jurisdictional factor of 75.95 percent to customer deposits is inconsistent with our prior practice. A jurisdictional factor of 100 percent for customer deposits was used in Florida Power & Light Company's 1983 rate case.[36] We believe it is appropriate to use 100 percent of the customer deposits in the capital structure for the purposes of setting rates in this case.

Based on the foregoing, we find that a capital structure that reflects PEF's proposed capital structure for the projected 2010 test year on MFR Schedule D-1a, page 1 of 3, with

[36] Order No. 13948, issued December 28, 1984, in Docket No. 830465-EI, In re: Petition of Florida Power and Light Company for an increase in rates.

specific adjustments to remove the $711 million of imputed equity from common equity and increase the jurisdictional factor applied to customer deposits from 75.95 percent to 100 percent is appropriate. This capital structure is supported by competent and substantial evidence in the record. Accordingly, the appropriate capital structure for the purpose of setting rates in this proceeding is shown on Schedule 2, attached hereto.

G. Cost Rate for Short-term Debt

PEF proposed a cost rate of 5.25 for short-term debt for the projected 2010 test year. This rate is comprised of an assumed commercial paper (CP) borrowing rate of 4.50 percent, plus fees associated with its credit facility of 0.75 percent. PEF based its 4.50 percent CP interest rate assumption on an estimated yield spread over the projected three-month London Interbank Offered Rate (LIBOR) rate.

PEF's projected three-month LIBOR rates for 2009 and 2010 are based on an implied three-month LIBOR forward curve from Bloomberg dated November 24, 2008. The three-month LIBOR rates PEF used for 2010 from the Bloomberg forward curve are as follows:

Q1 2010 = 1.65%
Q2 2010 = 1.35%
Q3 2010 = 1.10%
Q4 2010 = 2.90%

The average of the four three-month LIBOR rates for 2010 is 1.75 percent. The three-month LIBOR rates PEF used for 2009 from the Bloomberg forward curve are as follows:

Q1 2009 = 2.98%
Q2 2009 = 2.75%
Q3 2009 = 2.95%
Q4 2009 = 1.94%

The average of the four, three-month LIBOR rates for 2009 is 2.66 percent. We agree with witness Woolridge that 2.66 percent is significantly above the three-month LIBOR rates that have existed in 2009. We concur that the average three-month LIBOR rate for 2009 is approximately 1.00 percent. The three-month LIBOR rate was at 0.30 percent at the time of witness Woolridge's cross examination on September 29, 2009. We believe the record indicates the data PEF provided for the implied three-month LIBOR forward curves from Bloomberg for 2009 and 2010 is stale and has been shown to be overstated.

We believe that the record supports a range of 1.00 percent to 1.25 percent for an estimated three-month LIBOR rate for 2010. For ratemaking purposes, we believe a fair estimate is the median of that range or 1.12 percent.

To achieve its forecasted CP borrowing rate, PEF added an estimated yield spread over the three-month LIBOR rate for 2010. PEF indicated that spreads would range from 160 basis points to 340 basis points. PEF provided no documents to support its assumed yield spread. We agree with witness Woolridge's methodology explained in his direct testimony to interpolate an assumed yield spread. Using the data for 2009, witness Woolridge subtracted the average three-month LIBOR rate implied from the Bloomberg LIBOR forward curve of 2.66 percent from PEF's assumed CP borrowing rate of 4.50 percent which resulted in an assumed CP yield spread of 1.845 percent. We believe this estimate is supported by PEF's CP yield spreads for the last four months of 2008. In its response to OPC's Fourth Set of Interrogatories, No. 168, PEF stated, "[o]ur commercial paper rates in the last 4 months of 2008 had spreads to three-month LIBOR ranging from -7 basis points to +333 basis points . . ." The central tendency of the range of negative 7 to 333 basis points is a median of 163 basis points. Therefore, we find an assumed CP yield spread of 184.5 basis points for 2010 is reasonable.

The third component of the cost rate for short-term debt is the fees associated with PEF's credit facility. We agree with witness Sullivan that the appropriate adjustment for credit facility fees is 0.75 percent. The record shows that PEF is obligated to pay annually 0.07 percent of the $450 million credit facility committed to PEF by the lenders. PEF is also obligated to pay an annual administrative agency fee of $25,000 for the credit facility. PEF also amortized the expenses associated with fees incurred to originate the credit facility in March 2005. PEF estimated that the amortization is expected to be approximately $145,000 in 2010. The total amount of the fees is $485,000. PEF divided the amount of the fixed fees by the projected amount of the 13-month average outstanding balance for short-term debt during the projected 2010 test year to arrive at a cost rate of 0.75 percent for the credit facility fees ($485,000 ÷ $65,051,000 = 0.75).

In his testimony, witness Woolridge used 0.21 percent to account for the credit facility fees in his computation for the short-term debt cost rate. He did not provide any testimony that explains how he arrived at 21 basis points for the credit facility fees.

We believe the record supports a cost rate for short-term debt of 3.72 percent for the projected 2010 test year. To arrive at the cost rate, we utilized the same methodology as PEF and OPC but used different inputs in its computation. We used an estimated three-month LIBOR rate of 1.12 percent and added an assumed CP yield spread of 1.85 percent to arrive at the projected CP borrowing rate of 2.97 percent. We added 75 basis points for the cost of credit facility fees to the CP borrowing rate of 2.97 percent for a total cost rate for short-term debt of 3.72 percent. Accordingly, we find that the appropriate cost rate for short-term debt for the projected 2010 test year is 3.72 percent.

H. Cost Rate for Long-term Debt

PEF asserted that its projected cost rate for long-term debt of 6.42 percent reflects expected future interest rates for a mix of ten-year and thirty-year bonds. PEF argued that its projected cost rate is reasonable because interest rates are expected to increase in the future and PEF has historically issued a mix of ten-year and thirty-year bonds.

OPC proposed a cost rate for long-term debt of 6.05 percent. OPC witness Woolridge asserted that PEF's cost rate for long-term debt includes a projected ten-year bond issue on March 1, 2010 at a coupon rate of 6.98 percent. OPC Witness Woolridge testified that the current yields on ten-year, A and BBB+ rated utility bonds are 5.19 percent and 5.60 percent, respectively. He argued that PEF's projected bond yield of 6.98 percent is not reflective of current market interest rates. In his testimony, witness Woolridge stated that he used PEF's 2009 projected long-term debt cost rate of 6.05 percent in his cost of capital for PEF.

PEF Witness Sullivan disagreed with witness Woolridge's recommended cost rate for long-term debt of 6.05 percent. Witness Sullivan argued that witness Woolridge chose to use the overall embedded long-term debt cost rate for 2009 as the long-term debt cost rate for 2010. Witness Sullivan asserted that PEF currently has a $300 million first mortgage bond with an interest rate of 4.50 percent that matures on June 1, 2010. Witness Sullivan argued that in order for the 2010 long-term debt cost rate to remain at the 2009 embedded cost rate of 6.05 percent, the new $750 million bond projected to be issued in 2010 would have to be issued at a rate of 4.30 percent. He maintained that PEF's projected yield is based on expected future market interest rates, not current interest rates. Witness Sullivan argued that the yields on ten-year and thirty-year U.S. Treasury notes/bonds are expected to increase to well over 4.00 percent and 5.00 percent, respectively, in 2010. Witness Sullivan argued that using only current ten-year bond rates as a proxy for rates in the future leads to unrealistically low new debt issuance cost assumptions for 2010.

The disagreement between the parties centers on the difference between the parties' estimated coupon rate on PEF's projected issuance of a new $750 million ten-year bond on March 1, 2010. PEF based its estimate on forecasted ten-year and thirty-year U.S. Treasury yields and the estimated spreads above those yields. PEF used the ten-year bond in its financial forecast but based its estimated interest rate on the average coupon rate on ten-year and thirty-year bonds. PEF used the average of the coupon rates for a ten-year issuance of 6.63 percent and a thirty-year issuance of 7.33 percent. PEF based its estimate of the ten-year coupon rate on an estimated spread of 197 basis points above a forecasted U.S. Treasury yield of 4.66 percent. PEF based its estimate of the thirty-year coupon rate on an estimated spread of 207 basis points above a forecasted thirty-year U.S. Treasury yield of 5.26 percent. PEF's 6.98 percent interest rate was originally calculated in June 2008. PEF believes a blended coupon rate of 6.98 percent in 2010 is still a reasonable estimate given the continued uncertainty in the market and volatility in U.S. Treasury yields and credit spreads.

We believe that PEF's methodology to average the ten-year and thirty-year estimated bond yields to arrive at its estimate for the coupon rate of 6.98 percent is unreasonable. PEF's projected bond issuance on March 1, 2010, has a maturity of ten years. We believe it is more appropriate to use an estimated coupon rate that matches the maturity of the bond. We agree with OPC that PEF's projected yield of 6.98 percent is not reflective of current market interest rates. However, OPC did not provide testimony demonstrating what PEF's embedded cost of long-term debt would be using its proposed coupon rate of about 5.50 percent. Conversely, we agree with PEF that using the embedded cost rate for long-term debt from 2009 as a proxy for the rate in 2010 is not reasonable.

We believe the record reflects that 5.64 percent is the most reasonable estimate for the coupon rate of PEF's projected issuance of a new $750 million bond on March 1, 2010. The ten-year U.S. Treasury forward curve from Bloomberg forecasts that the yield on ten-year U.S. Treasury bonds will be 3.67 percent on February 22, 2010. Adding PEF's estimated spread of 197 basis points for a ten-year bond to the forecasted ten-year U.S. Treasury bond yield of 3.67 percent results in an estimated coupon rate of 5.64 percent. The estimated interest rate of 5.64 percent is also in line with OPC's estimated interest rate. In his testimony, witness Woolridge provided a chart showing the yields on ten-year, A and BBB+ rated utility bonds. The current yield is 5.6 percent for BBB+ rated utility bonds. PEF's current S&P credit rating for its senior unsecured long-term debt is BBB+.

To calculate the appropriate embedded cost of long-term debt, we made an adjustment to MFR Schedule D-4a. We substituted PEF's estimated coupon rate of 6.98 percent with the coupon rate of 5.64 percent on line 15 in MFR Schedule D-4a. The result reduced the interest expense for the new issuance for the projected test year. The lower interest expense reduced the embedded cost rate of long-term debt from 6.42 percent to 6.18 percent. As such, we believe the record reflects that the more reasonable estimate of the coupon rate for PEF's projected issuance of a new $750 million bond on March 1, 2010, is 5.64 percent. Accordingly, we find that the appropriate embedded cost rate for long-term debt for the projected test year is 6.18 percent.

I. Return on Equity

Two witnesses testified in this proceeding regarding the appropriate return on equity (ROE) for PEF. PEF witness Vander Weide recommended an ROE of 12.54 percent. OPC witness Woolridge recommended an ROE of 9.75 percent. As expressly stated in the 2005 Stipulation, PEF does not currently have an authorized ROE.[37] However, for purposes other than reporting or assessing earnings (such as cost recovery clauses or AFUDC), the 2005 Stipulation provided for PEF to use an ROE of 11.75 percent.

The statutory principles for determining the appropriate rate of return for a regulated utility are set forth by the U.S. Supreme Court in its Hope and Bluefield decisions.[38] These decisions define the fair and reasonable standards for determining rate of return for regulated enterprises. Namely, these decisions hold that the authorized return for a public utility should be commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to maintain its ability to attract capital under reasonable terms.

While the logic of the legal and economic concepts of a fair rate of return are fairly straight-forward, the actual implementation of these concepts is controversial. Unlike the cost rate on debt that is fixed and known due to its contractual terms, the cost of equity is a forward-looking concept and must be estimated. Financial models have been developed to estimate the

[37] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc., p. 3 – 4.
[38] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944); and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, Capital Asset Pricing Model (CAPM), and ex ante Risk Premium (RP) model are generally recognized as being consistent with the market-based standards of a fair return enunciated in the Hope and Bluefield decisions.

1. Discounted Cash Flow Model

Both witnesses used the Discounted Cash Flow (DCF) model to estimate the investor-required ROE for PEF. Because PEF is a wholly-owned subsidiary of Progress Energy, its common stock is not publicly traded. To apply the model, each witness had to select a group of companies with publicly traded stock to serve as a proxy for PEF.

a. PEF witness Vander Weide

To select his group of comparable companies, PEF witness Vander Weide started with all electric utilities followed by Value Line Investment Survey (Value Line). From this initial sample, he removed all companies that were actively involved in a merger, had reduced or eliminated its dividend in the last two years, or had not paid a dividend in every quarter of the last two years. He further narrowed his proxy group by including only the companies with an investment grade bond rating; a Value Line Safety Rank of 1, 2, or 3; and had at least three analyst projections included in the I/B/E/S earnings growth forecast. Based on this selection criteria, witness Vander Weide identified a group of 24 companies in his direct testimony and a group of 32 companies in his rebuttal testimony that he testified represented "a reasonable proxy for the risk of investing in PEF."

Witness Vander Weide used the quarterly DCF model. In his direct testimony, he relied on stock prices for the three month period ended November 2008 and in his rebuttal testimony he relied on stock prices for the three month period ended July 2009. All stock prices were as reported by Thomson Reuters. He derived the estimated quarterly dividends based on past dividends as reported by Value Line. In his direct testimony, he relied on five year forecasts of earnings per share (EPS) growth rates from I/B/E/S as of November 2008 and in his rebuttal testimony he relied on EPS growth rates as of July 2009. His DCF model included a five percent adjustment for flotation costs.

The result of witness Vander Weide's DCF model based on data as of November 2008 indicated a market-weighted average cost of equity of 12.3 percent. The result of his DCF model based on data as of July 2009 indicated a market-weighted average cost of equity of 11.5 percent.

b. OPC witness Woolridge

To select his group of comparable companies, OPC witness Woolridge started with all electric utilities followed by Value Line and AUS Utility Reports. From this initial sample, he removed all companies that did not have an investment grade bond rating from Moody's and/or S&P, and a three year history of paying dividends. He further narrowed his proxy group by focusing on companies with operating revenues less than $15 billion and that generate at least 75 percent of their operating revenues from regulated electric operations. Based on this selection criteria, witness Woolridge identified a group of 15 comparable companies for use in his analysis.

Witness Woolridge used the annual DCF model. He relied on dividend yields for the six month period ended July 2009 and for the month of July 2009 as reported by AUS Utility Reports. He relied on Value Line's historical and projected growth rate estimates for EPS, dividends per share (DPS), and book value per share (BVPS). In addition, he used the average EPS growth rate forecasts from Yahoo First Call, Zacks, and Reuters and the expected growth rate as measured by the earnings retention method. Witness Woolridge's DCF analysis did not include an adjustment for flotation costs. In addition to applying the DCF model to his own proxy group, witness Woolridge also applied his model to the proxy group identified in witness Vander Weide's direct testimony. The indicated return from witness Woolridge's DCF analysis is 10.3 percent when applied to his proxy group and 10.5 percent when applied to witness Vander Weide's proxy group.

c. Rebuttal

Each witness filed testimony challenging the reasonableness of certain aspects of the other witness' DCF analysis. Both witnesses used generally accepted versions of the DCF model, similar estimates of the dividend yields, and relatively comparable proxy groups from a risk perspective. The primary reason for the difference in indicated returns between the two witnesses' DCF analyses is their respective estimates of the growth rate to include in the DCF model.

PEF witness Vander Weide used five year forecasts of analyst estimates of future EPS growth as reported by I/B/E/S in his DCF analysis. The average growth rate included in witness Vander Weide's DCF model was 7.3 percent. He testified that he relied exclusively on analyst forecasts of EPS growth to estimate the investor-expected growth rate in the DCF model because there is empirical evidence that investors rely on analysts' forecasts to estimate future earnings growth.

OPC witness Woolridge used historical and projected growth rate estimates for EPS, DPS, and BVPS from Value Line; analyst EPS growth rates from Yahoo First Call, Zacks, and Reuters; and an estimate of the sustainable growth rate to develop the growth rate estimate used in his DCF analysis. The average growth rate included in witness Woolridge's DCF model was 4.75 percent. He testified that he did not rely exclusively on EPS forecasts because the appropriate growth rate in the DCF model is the dividend growth rate, not the EPS growth rate, and because evidence indicates Wall Street security analyst EPS forecasts are overly optimistic and upwardly biased. Witness Woolridge acknowledged that over the long-run, dividend and earnings will grow at a similar growth rate. He also testified that investors presumably will use some combination of historical and/or projected growth rates for earnings and dividends in their analyses. For these reasons, witness Woolridge relied on a number of measures for growth in his DCF analysis, not just EPS growth rates.

Relative to the impact the growth rate used in a DCF analysis has on the indicated return, the other differences between the two witnesses' application of the DCF model are rather modest in comparison. The incremental difference in indicated returns between a quarterly DCF model and an annual DCF model is approximately 17 basis points. The incremental difference in indicated returns between a DCF analysis with an adjustment for flotation costs and a DCF model without this adjustment is approximately 25 basis points. Any difference related to which witness' electric utility proxy group is more comparable to PEF was not considered to be meaningful in this case. As a result, the decision regarding which DCF result is more indicative of investors' required return for an investment in PEF comes down to which witness' estimate of growth is believed to be more appropriate.

2. Capital Asset Pricing Model (CAPM)

Both witnesses relied on the CAPM approach to estimate the investor-required ROE for PEF. For the reason discussed earlier, the witnesses used their respective proxy groups for certain inputs to their CAPM analyses.

a. PEF witness Vander Weide

PEF witness Vander Weide performed both an ex ante and an ex post CAPM analysis. For his estimate of the risk-free rate, he used the forecasted yield on 10-year and 30-year U.S. Treasury bonds as published by Blue Chip Financial Forecast (Blue Chip) to derive the forecasted yield on 20-year U.S. Treasury bonds of 4.87 percent used in his analysis. For the estimate of the company-specific risk, or beta, he used the average Value Line beta for his group of proxy companies of .79. He derived a risk premium of 8.83 percent for use in his ex ante, or DCF-based, CAPM analysis and a risk premium of 7.10 percent for use in his ex post, or historical, CAPM analysis. Witness Vander Weide's analysis indicated a return of 11.8 percent based on his ex ante CAPM approach and a return of 10.7 percent based on his ex post CAPM approach.

b. OPC witness Woolridge

OPC witness Woolridge performed an ex ante CAPM analysis. For the risk-free rate, he used an estimate of the forward-looking yield on 30-year U.S. Treasury bonds of 4.50 percent. For beta, he used the average Value Line beta for his group of proxy companies of .70. He determined an expected risk premium of 4.37 percent based on the results of various studies of historical risk premium, ex ante risk premium studies, and equity risk premium surveys. Witness Woolridge's CAPM analysis indicated an ROE of 7.6 percent.

c. Rebuttal

Each witness filed testimony challenging the reasonableness of certain aspects of the other witness' CAPM analysis. Both witnesses used relatively similar betas (.79 and .70). While their respective estimates of the risk-free rate are not that similar (4.87 percent and 4.50 percent, respectively), the primary reason for the difference in their indicated CAPM results is the significant difference between their respective risk premium estimates.

Witness Vander Weide testified that the average yield on Moody's Baa-rated utility bonds over the last year was 7.72 percent. Since an investment in a company's equity is more risky than an investment in its bonds, a company's cost of equity should be higher than its cost of debt. Because witness Woolridge's CAPM estimate of 7.6 percent is less than the average yield on Baa-rated utility bonds, witness Vander Weide testified that witness Woolridge's CAPM result is below a reasonable range of estimates of PEF's cost of equity.

Witness Woolridge testified that witness Vander Weide's CAPM results are unreasonable because the risk-free rate and risk premiums witness Vander Weide used in his analysis are overstated. As noted above, witness Vander Weide used a risk-free rate of 4.87 percent. Witness Woolridge testified that the current risk-free rate is approximately 4.00 percent. In addition, witness Woolridge testified that witness Vander Weide's risk premiums of 7.10 and 8.83 percent are inflated and excessive. For these reasons, witness Woolridge testified that witness Vander Weide's CAPM results are above a reasonable range of estimates of PEF's cost of equity.

While each witness disagreed with the other witnesses' approach to performing the CAPM analysis, they both agreed that under current market conditions the CAPM produced less reliable cost of equity results for electric utilities at this time. Witness Vander Weide testified that due to the efforts of the U.S. Treasury to keep interest rates low, the spread between the risk-free rate and the interest rate on public utility debt has increased. Because the CAPM relates the cost of equity to the yield on government securities, and yields on government securities are abnormally low due to the U.S. Treasury's efforts to stimulate the economy, he believes the CAPM approach understates the utility cost of equity. In his own analysis, witness Woolridge gave primary weight to his DCF analysis in determining his recommended ROE for PEF.

3. Risk Premium (RP) Model

In addition to the DCF and CAPM analyses, PEF witness Vander Weide also performed two versions of the RP analysis. In his ex ante RP method, he applied his DCF model to the Moody's Index of electric companies. He compared the results of this DCF analysis to the concurrent interest rate on Moody's A-rated bonds. This comparison indicated an estimated risk premium of 4.9 percent. He derived a forecasted yield to maturity on A-rated utility bonds of 6.3 percent based on information from the December 2008 Blue Chip. Based on this approach, witness Vander Weide's ex ante RP model indicated an ROE of 11.2 percent.

In his ex post RP method, witness Vander Weide relied on historical, earned returns for the S&P 500 stock portfolio and the S&P Utilities stock portfolio for the period 1937 – 2008. The average annual return on an investment in the S&P 500 stock portfolio is 11.4 percent and the average annual return on an investment in the S&P Utilities stock portfolio is 11.0 percent. The average annual return on an investment in the Moody's A-rated utility bond portfolio was 6.4 percent. Thus, he concluded that the risk premium on the S&P 500 index is 5.0 percent and on the S&P Utility index is 4.6 percent. He used the average of these two risk premiums, or 4.8 percent, as his estimate of the risk premium in this approach. Adding the 4.8 percent risk premium to the forecasted interest rate on Moody's A-rated bonds of 6.3 percent discussed earlier, he obtained an indicated ROE of 11.1 percent. Adding 25 basis points for flotation costs, witness Vander Weide obtained an estimate of 11.4 percent as the cost of equity for PEF using the ex post risk premium method.

OPC witness Woolridge testified that there are a number of errors in PEF witness Vander Weide's RP analyses. Witness Woolridge testified that witness Vander Weide's ex ante RP result is overstated due to an inflated base interest rate and an excessive risk premium. He testified that the current yield on long-term, A-rated utility bonds is less than 6.0 percent, well below the 6.3 percent assumed in witness Vander Weide's analysis. In addition, witness Woolridge testified that witness Vander Weide's ex ante, or DCF-based, RP method suffers from the same deficiencies discussed earlier in the section on the stand-alone DCF model. Because witness Vander Weide's DCF component to this approach relied exclusively on EPS growth and thus overstated investor-required returns, witness Woolridge testified that this approach produced upwardly biased results.

Witness Woolridge testified that witness Vander Weide ex post RP method suffered from similar flaws. The issue related to the base interest rate was discussed above. In addition, witness Woolridge testified that witness Vander Weide's ex post risk premium is excessive because he relied on historical, earned returns to estimate the forward-looking market risk premium. Witness Woolridge noted the numerous academic studies and other empirical evidence which demonstrate that using the historical relationship between stocks and bond returns to measure an ex ante risk premium is erroneous.

4. Adjustments

In arriving at his recommended return of 12.54 percent for PEF, witness Vander Weide made two specific adjustments in his analysis. To allow for the recovery of flotation costs associated with the issuance of common equity, he made an adjustment to his DCF model and DCF-based CAPM and RP approaches that equates to 25 basis points. For his non-DCF-based CAPM and RP approaches, he added 25 basis points to the indicated returns. Witness Vander Weide testified that all firms that have sold securities in the capital markets have incurred some level of flotation costs, including underwriters' commissions, legal fees, printing costs, etc. He stated that these costs range between three and five percent of the proceeds of an equity issuance. In addition to these costs, for large equity issuances, there can be a decline in the price of the shares. On average, he said that the decline due to market pressure has been from two to three percent of the proceeds. Thus, total flotation costs, including both issuance expense and market pressure, could range from five to eight percent of the proceeds of an equity issuance. For this reason, witness Vander Weide believed a five percent allowance for flotation costs was a conservative estimate that should be recognized in the determination of the ROE.

OPC witness Woolridge testified that it is not necessary to make an upward adjustment to the cost of equity for the recovery of flotation costs. He stated that PEF has not identified any actual flotation costs for the Company. In addition, because electric utilities have market-to-book ratios in excess of 1.0x, he testified that there should be a flotation cost reduction (and not increase) to the equity cost rate. Finally, he argued that investors also incur transaction costs when they purchase shares. If these transaction costs are taken into account, the price of shares would be higher. If witness Vander Weide had included these transaction costs in his DCF analysis, the higher effective stock prices paid for stocks would have led to lower dividend yields. This would have resulted in a downward adjustment to his DCF equity cost rate. For these reasons, witness Woolridge testified that it is unnecessary to recognize a flotation cost adjustment in the determination of the investor-required ROE.

Based on his application of the various cost of equity models, witness Vander Weide concluded that the cost of equity for his proxy group was 11.5 percent. However, because the average market value equity ratio of the companies in his proxy group exceeded the book value equity ratio of PEF that would be recognized for purposes of setting rates, he argued it was necessary to make a leverage adjustment to equate PEF's weighted average cost of capital on a book value basis to the weighted average cost of capital for his proxy group on a market value basis. This adjustment equated to 104 basis points, and when added to his indicated return for the proxy group of 11.5 percent, produced the 12.54 percent ROE witness Vander Weide recommends is a fair rate of return on equity for PEF.

OPC witness Woolridge testified that this leverage adjustment is unwarranted. He testified that witness Vander Weide's proposed adjustment inappropriately mixes book value and market value equity capitalization ratios. He noted that financial publications, investment firms, and this Commission report and work with capitalization ratios on a book value basis, not a market value basis. Moreover, to the extent that a company's market value exceeds its book value, witness Wooldridge testified that this shows that the company is earning a return on equity in excess of its cost of equity. Finally, witness Woolridge noted that witness Vander Weide could not identify any proceeding in which the regulatory commission had adopted his leverage adjustment.

5. <u>Analysis</u>

Based on a literal reading of the testimony in this proceeding, the record could support an authorized ROE within the range of 7.6 percent to 12.54 percent. As noted earlier, the witnesses' recommended returns suggest a range of 9.75 percent to 12.54 percent.

Both witnesses recognized that the generally accepted models used for estimating ROE are based on a number of restrictive assumptions. Under normal economic circumstances, the relaxation of these assumptions for the practical application of these models is generally understood. And while the state of the economy has improved since the market disruption in the fall of 2008, the economic recovery is still somewhat tenuous. This realization does not mean the models no longer have value; rather, it is particularly important at this point in time to exercise informed judgment in the application of the models.

Each witness argued that the other witness made certain assumptions in the application of their respective DCF analysis that either understated or overstated the investor-required ROE for PEF. As discussed earlier, the majority of the differences between the two witnesses' respective DCF approaches have only a marginal impact on the difference in the indicated returns. The primary reason for the difference in the witnesses' DCF results relates to their respective estimates of the growth rate to include in the DCF model. The results of the witnesses' DCF analyses based on financial data as of July 2009 produced a range of 10.3 percent to 11.5

percent. Recognizing that the top end of this range represents a DCF result based exclusively on EPS growth forecasts, we believe this is a conservatively high estimate of the investor-required return.

Each witness argued that the other witness made certain assumptions in the application of their respective CAPM approaches that either understated or overstated the investor-required ROE for PEF. However, recognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, we believe models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.

Due to the academic studies and other empirical research documenting that RP models based on historical earned returns are poor predictors of current market expectations, we have reservations regarding the reliability of the results of witness Vander Weide's ex post RP model. While witness Woolridge also expressed concerns regarding the results of witness Vander Weide's ex ante RP model as well, we note that witness Vander Weide's ex ante risk premium of 4.9 percent is not significantly greater than witness Woolridge's ex ante risk premium of 4.4 percent.

Both witnesses made persuasive arguments for including and not including an allowance for the recovery of flotation costs in the determination of the ROE. While it has been our practice to recognize an adjustment for flotation costs in certain applications, the determination of an authorized ROE by a regulatory commission in an evidentiary proceeding very seldom involves the level of specificity that would permit the itemization of a specific allowance for flotation costs. In this context, the debate over whether to include or not include an allowance for flotation costs is similar to the debate over whether to use an annual or quarterly DCF model or a blended growth rate or an earnings-only growth rate in the DCF analysis. The approved ROE does not specifically recognize or exclude an allowance for flotation costs but rather represents a blend of the results of the witnesses' analyses, some that include and others that do not include an adjustment for flotation costs.

We do not believe witness Vander Weide's proposed 104 basis point leverage adjustment to his estimated equity cost rate is appropriate. While the logic of the leverage adjustment proposed by witness Vander Weide is sound, the inappropriate mixing of market value and book value capitalization ratios in the formula is a fatal flaw. Witness Vander Weide testified that PEF's ratemaking capital structure contained an appropriate mix of debt and equity and was an appropriate capital structure for ratemaking purposes. In addition, he was afforded multiple opportunities to make a comparison of PEF's ratemaking capital structure to the equivalent capital structures of the investor-owned utilities (IOUs) of the companies in his proxy group but declined to do so. Finally, even though he testified that he has been including this leverage adjustment in ROE testimony since the early 1990's, witness Vander Weide was unable to identify any Commission decision involving an electric utility that had recognized this adjustment.

Due to the reliance on historical earned returns to estimate the current risk premium in the ex post CAPM and RP models, concerns over the exclusive reliance on EPS growth rates in the DCF analyses, and the decision to recognize an inappropriately quantified leverage adjustment, we believe the Company's requested ROE of 12.54 percent overstates the current investor-required ROE for PEF. Conversely, recognizing that the marginal cost of long-term, single A-rated utility bonds is near 6.0 percent, we believe returns in the single digits as recommended by the Intervenors may understate the investor-required ROE in the current market.

Finally, Exhibit 264 reports the authorized ROEs set during 2009 for the electric utilities followed by Regulatory Research Associates (RRA). The ROEs set during 2009 ranged from a low of 8.75 percent to a high of 11.5 percent and averaged 10.51 percent for the group. While we do not believe the authorized ROE for PEF should necessarily be based upon the average return set by Commissions during 2009, we do not believe recommended returns significantly above or below this level are indicative of the investor-required return for PEF, either.

Based on the foregoing, we find that an authorized ROE of 10.5 percent with a range of plus or minus 100 basis points is appropriate. In arriving at this return, we have weighed the identified strengths and weaknesses associated with the respective witness' analyses. We have also taken into account PEF's proposed construction program and its need to access the capital markets under reasonable terms. In addition, we also considered the equity ratio previously discussed. We find that an authorized ROE of 10.5% is supported by competent, substantial evidence in the record and satisfies the standards set forth in the Hope and Bluefield decisions of the U.S. Supreme Court regarding a fair and reasonable return for the provision of regulated service.

J. Weighted Average Cost of Capital

The weighted average cost of capital is dependent upon other factors, including but not limited to, accumulated deferred income taxes, unamortized investment tax credit, imputed equity adjustment for purchased power obligations, equity ratio, reconciliation of rate base to capital structure, jurisdictional capital structure, cost rate for short-term debt, cost rate for long-term debt, and the appropriate return on equity. Based on our decision, the weighted average cost of capital is 7.88 percent.

The net effect of these adjustments is a decrease in the overall cost of capital from the 9.21 percent return requested by PEF to a return of 7.88 percent. Schedule 2, attached hereto, reflects the test year capital structure. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year, we find that the appropriate weighted average cost of capital for PEF for purposes of setting rates in this proceeding is 7.88 percent.

IX. NET OPERATING INCOME

A. Total Operating Revenues

Based on our approved stipulations, there are no adjustments to PEF's forecasts of customers, kWh, kw, inflation factors or billing determinants for the 2010 projected test year. However revenues at current rates for the projected test year should be increased by

$132,101,000 to account for the Bartow Repowering Project (BRP) base rate increase approved by us in Order No. PSC-09-0415-PAA-EI.[39] Therefore, we find that $1,650,019,000 is the appropriate projected level of total operating revenues for the 2010 projected test year, as reflected on Schedule 3 attached hereto.

B. Bartow Repowering Project

The revenue requirements related to the Bartow Repowering Project are included in the 2010 projected amounts; therefore, we find that no adjustments to the proposed revenues are necessary.

C. Adjustments to Remove Revenues and Expenses Recoverable through the Conservation Cost Recovery Clause

We find that PEF has made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause.

D. Adjustments to Remove Revenues and Expenses Recoverable through the Fuel and Purchased Power Cost Recovery Clause

We find that PEF has made the appropriate test year adjustments to remove fuel and purchased power revenues and expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause.

E. Adjustments to Remove Revenues and Expenses Recoverable through the Capacity Cost Recovery Clause

We find that PEF has made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause.

F. Adjustments to Remove Revenues and Expense Recoverable through the Environmental Cost Recovery Clause

We find that PEF has made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause.

G. Aviation Cost

PEF removed corporate aircraft costs in the amount of $3,126,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $1,921,000. The explanation given by PEF is to exclude cost of corporate aircraft in order to comply with Commission guidelines. PEF does not own any airplanes or helicopters. Since PEF does not own aircraft, and an adjustment has been made to remove all corporate aviation expense allocations, we believe that all aviation

[39] Order No. PSC-09-0415-PAA-EI, issued June 12, 2009, in Docket No. 090144-EI, In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.

costs have been removed. Accordingly, we find that PEF has made the appropriate adjustments to remove aviation cost for the test year.

H. Advertising Expenses

PEF removed promotional advertising costs in the amount of $3,388,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $2,081,000. The explanation given by PEF is to exclude the cost of promotional advertising in order to comply with our guidelines.

We note an excerpt from the procedures followed by our auditors for the 2008 base year:

> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

The Company's advertising expense is one of the areas specifically examined by our auditors. There were no findings with respect to this issue. Therefore, we find that PEF has made the appropriate adjustments to remove advertising expenses for the test year.

I. Directors and Officers (D&O) Liability Insurance

PEF argued that OPC witness Schultz is incorrect in his assertion that D&O liability insurance does not benefit ratepayers, and thus should be disallowed. PEF cited to the most recent TECO case in which this Commission decided that D&O liability insurance is a necessary and reasonable business expense and is appropriately included in customers' rates.[40] PEF asserted that we have already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for us to depart from its previous findings in this case.

OPC witness Schultz questioned whether the cost of D&O liability insurance is a necessary and appropriate expense to pass on to ratepayers. He stated that the expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. He noted that the Company included $2.2 million in Account 925 for D&O liability insurance, but he believes the correct amount to be $2,750,650 for $300,000,000 in coverage. He disagreed with our recent Peoples Gas case in which the expense was allowed as a legitimate business expense.[41] The witness testified that the pertinent issue is whether the cost is beneficial to ratepayers, not whether it is a legitimate business expense. He stated that we have disallowed the cost in the past.

OPC witness Schultz testified that other jurisdictions have disallowed the expense. He stated, for example, that a Connecticut decision limited recovery by Connecticut Light and

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[40] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

[41] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 37-38.

Power to thirty percent, because ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. He added that Consolidated Edison was not allowed to recover the full amount in a New York case. He explained that the disallowance was due to excessive coverage in part, and that a portion of the amount found to be reasonable was also disallowed. He stated the reason for the additional disallowance was that D&O Liability insurance provides protection to shareholders from matters in which the customers have no influence.

OPC witness Schultz recommended disallowance of the total cost of D&O liability insurance of $2,750,650 ($2,412,100 jurisdictional) because the purpose of the insurance is to protect shareholders, not ratepayers. He stated that he does not take the position that the Company should not have the insurance, but that it should be paid for by those who benefit from the insurance; that is, the shareholders.

OPC argued that PEF did not offer any testimony in rebuttal to OPC witness Schultz that the D&O liability insurance should be disallowed. OPC stated that, in each of the cases cited by witness Schultz in his testimony, the Company argued that D&O liability insurance is a necessary and prudent cost required to attract and retain competent directors and officers, yet a disallowance was made. OPC challenged the cost for $300,000,000 of coverage as being excessive, and questioned whether the cost for that level of coverage is appropriate to pass on to ratepayers.

OPC noted in particular a Consolidated Edison Company Case. OPC stated that in the final decision, the New York Commission (NYC) ruled that $300,000,000 of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100,000,000 excess, and then disallowed 50 percent of the premium associated with the $200,000,000 that was determined to be reasonable. OPC stated that, in the discussion, the NYC noted that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place, while customers have no influence. OPC noted that the NYC further stated at page 91 of its order that:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

FIPUG argued that the amount should be disallowed, because the expense directly benefits only PEF's shareholders.

We agree with OPC witness Schultz that this Commission has disallowed D&O insurance in water and wastewater cases in the past.[42] We do not agree with OPC that the ratepayers do not

[42] See Order Nos. PSC-09-0385-FOF-WS, issued May 29, 2009, in Docket No. 080121-WS, In re: Application for increase in water and wastewater rates in Alachua, Brevard, DeSoto, Highlands, Lake, Lee, Marion, Orange, Palm

benefit from D&O liability insurance. We believe that D&O liability insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers with out it. We also believe that ratepayers receive benefits from being part of a large public company, such as easier access to capital which may result in lower rates. As stated in the TECO order:

> We find that [D&O liability] insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain [D&O liability] insurance, including investor-owned electric utilities. . . . We do not agree with OPC that the ratepayers do not benefit from [D&O liability] insurance. It is not realistic to expect a large public company to operate effectively without [D&O liability] insurance.[43]

We agree with PEF that the amount of the D&O liability insurance provided in discovery responses is $2.2 million, not $2.75 million as adjusted by OPC witness Schultz. However, we note that the amount of the premium for the test year is projected to be higher than the premium for 2008-2009, but lower than the previous three years, even though the amount of coverage was increased from $280 million to $300 million.

In summary, we believe that D&O liability insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. We also believe that ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital. Because D&O liability insurance benefits both the ratepayer and the shareholder, it should be a shared cost. Thus, we find that O&M expense shall be reduced by $964,913 jurisdictional to reflect the sharing of costs between the ratepayers and the shareholders.

J. Injuries and Damages Expense

PEF stated that FERC Account 925 on MFR Schedule C-4, p. 44 of 48, reflects an expense of $8,882,000 for injuries and expenses. PEF stated that the numbers were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. PEF stated that it based its 2010 budget for injuries and damages expense on the Company's actual historical 2008 expenses. PEF argued that it is, therefore, entitled to recover this expense.

Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities Florida, Inc., p. 81; PSC-07-0505-SC-WS, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p.44; PSC-03-1440-FOF-WS, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p. 84; and PSC-99-1912-FOF-SU, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc., p. 20-22.

[43] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

PEF argued that injuries and damages expense has been recognized as a legitimate business expense in the Company's rates in the past. PEF noted that we have previously recognized it as a legitimate business expense.[44] PEF argued that there is no justification for the elimination of this expense in its entirety from the Company's revenue requirements and witness Schultz provides none.

OPC witness Schultz testified that the Company's request for injuries and damages expense is not supported by the record. He stated that MFR Schedule B-21, p. 1 of 4, did not show an expense for injuries and damages. He recommended an adjustment of $5,449,303 system or $4,778,603 jurisdictional.

OPC witness Schultz stated that information provided by PEF showed that $2,694,313 was included in various budget centers, and another $1,700,000 was included in the legal department's budget for injuries and damages. He testified that this information is incorrect in that there are additional amounts. He explained that the Company advised in response to discovery that an amount of $450,000 in salaries and wages in the nuclear budget should have been included in A&G Injuries and Damages. He concluded that all of these amounts and errors together totaled $4,844,313 ($2,694,313 + $1,700,000 + $450,000) of injuries and damages in the projected test year.

OPC witness Schultz testified that his analysis of the budget showed the costs included by the Company actually totaled $5,020,063, not $4,844,313. He stated that he found $1,825,000 in the legal budget, plus another $50,750 for injuries and damages, as compared to the $1,700,000 pointed out by the Company, as discussed above.) The witness stated that the $1,825,000 was verified in the response to OPC's Thirteenth Request for Production of Documents, No. 274.

OPC witness Schultz testified that PEF failed to provide any justification for its 2010 injuries and damages costs. He stated that the Company provided actual and budgeted costs for 2008 that showed a negative expense in 2008. He stated that it would not be appropriate for the Company to be allowed an expense in the projected test year when there was no expense in the base year 2008. He noted that there was no testimony or justification for any amount in 2010.

OPC stated that PEF did not offer any testimony either supporting the amount or rebutting Mr. Schultz's testimony on this point. OPC noted that the PEF witness for MFR Schedule B-21, witness Toomey, does not discuss injuries and damages in his testimony in this case. OPC argued that the adjustment of $5,449,303 or $4,778,603 jurisdictional is warranted. FIPUG stated that the amount should be disallowed because it is not supported in PEF's filing.

We agree with PEF that injuries and damages expense is a legitimate business expense. The issue here is whether the costs have been properly supported in the record and whether the Company will actually incur the amount of expense it has requested.

[44] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 63.

PEF stated that the numbers for this account were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. We have not found any specific information from the audit report that supports the numbers for this account. We note the following excerpt from the procedures followed by our auditors for the 2008 base year:

> We verified, based on a sample of utility transactions for select O&M expense accounts, that utility O&M expense balances are adequately supported by source documentation, prudent, utility in nature and do not include non-utility items.
>
> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

Although certain specific accounts were sampled, as noted above, there is no indication that the injuries and damages account was separated out for specific examination. The audit is based on samples. There is no information in the record from the audit that supports the Company's 2008 number on which its 2010 request is based.

PEF showed an amount for Injuries and Damages expense in Account 925 in its MFRs of $9,821,000 system, $8,612,000 jurisdictional for the 2010 test year. However, the amount is not properly reflected in MFR Schedule B-21, where it should be shown as an expensed amount in the right hand column, as noted by OPC witness Schultz. That column shows a zero amount. We believe the Company's response is correct that this is an error. We do not believe the error is a reason to disallow the expense.

In addition to the 2010 amount above, the Company showed a system amount of $8,882,000 ($8,142,000 jurisdictional) for 2008 in Account 925, and $9,942,000 system ($9,114,000 jurisdictional) for 2009. Compared to 2008 and 2009, staff believes the 2010 amount appears reasonable. However, the numbers for all three years are unsupported. OPC witness Schultz disagreed that this is the actual amount of expense for 2008, due to a credit of $836,977 from the Energy Delivery Department. Further, when the insurance cost for 2008 was removed from the account, witness Schultz determined that the amount of injuries and damages expense for 2008 was a negative $429,420. Without the Energy Delivery credit, the expense less insurance would have been only $489,697 for 2008, as calculated by staff using witness Schultz's schedules. There is no record evidence to support the large increase for 2010 over the 2008 amounts.

We agree with OPC witness Schultz that the amount of injuries and damages expense included in PEF's filing is actually $10,657,160 when the errors are corrected. Of that amount $5,637,097 is for insurance, as compared to insurance costs of $5,878,629 for 2008. The total expense less insurance is $5,020,063. ($10,657,160 – $5,637,097 = $5,020,063) The numbers are unrebutted.

PEF noted that $450,000 was classified as salaries and wages that should have been classified as injuries and damages expense. This amount was included as part of OPC witness Schultz's adjustment and does not need to be addressed separately.

PEF has not justified its request for injuries and damages expense. Although such expense is a legitimate business expense, the large increase over 2008 was not explained. The amount requested for 2010 less insurance is $5,020,063, as compared to actual expense for 2008 of ($429,240). As previously noted, even if the credits were removed for 2008, the actual expense excluding insurance would have been $489,697. The adjustment recommended by OPC witness Schultz allows the Company the full amount PEF requested for insurance, but removes all additional amounts. The adjustment is greater than the amount initially requested by PEF, due to the correction of several errors as previously discussed. We believe OPC's adjustment is appropriate given the lack of support for PEF's request and the large unexplained increase. As such, we find that a decrease of $4,778,603 jurisdictional ($5,020,063 system) or for 2010 injuries and damages expense is appropriate.

K. <u>A&G Office Supplies and Expenses</u>

The Company stated that it budgeted $1,208,000 to Salaries and Wages that should have been budgeted to A&G Office Supplies and Expense.

OPC witness Schultz recommended an adjustment of $2,331,755 jurisdictional comprised of several items included in A&G Office Supplies and Expense that he stated are not appropriate costs to be included in rates. He stated that the first adjustment of $1,488,677 included $1,268,677 for events such as the Tampa Bay Lightning for $59,900, the Tampa Bay Buccaneers for $139,527, the Orlando Magic for $20,000 and others. He stated that the two listings of events and costs are included in his exhibit HWS-3. He testified that the remaining $220,000 was for service awards.

OPC witness Schultz recommended removal of an additional $1,200,000 for what was shown by PEF as "Corporate Managed Account." He testified that the account appeared to be a large petty cash account for the president's budget center. He stated that PEF did not provide any supporting documentation for this expense, so the expense should be excluded from rates for lack of justification.

OPC witness Schultz stated that there is no evidence that the costs were removed from the test year. He testified that the costs were budgeted in Account 921, A&G Office Supplies and Expense. He explained that, in response to discovery, the Company supplied a reconciliation linking the budgeted costs to MFR Schedules C-1 and C-2. The witness noted that the only adjustments to O&M expense that removed budgeted costs were for aircraft and advertising; the A&G items did not fall into either category. Therefore, OPC argued that the Company did not offer supporting documentation or rebuttal testimony in rebuttal to this issue. FIPUG stated that $2,331,755 should be disallowed because the amount was not explained or justified in PEF's budget.

The testimony and proposed adjustment offered by OPC witness Schultz are unrebutted. Through examination of exhibits, we were able to determine that there is partial agreement on the part of PEF with the OPC adjustment. In response to the our audit, PEF agreed with Audit Finding No. 4 that a number of items included in A&G for 2008 were not utility related. The finding showed that the Company included items such as provision of hospitality beverages for the Arnold Palmer Invitational, food for the Honda Grand Prix, and a VIP suite. Some of the items from the audit finding are also included in the list of items supporting OPC witness Schultz's adjustment. The Company responded that it agreed with the audit finding and proposed an adjustment for 2010 in the amount of $482,479 jurisdictional ($544,000 system).

We agree with OPC witness Schultz's recommended adjustment of $2,688,677 system ($2,331,755 jurisdictional). In addition to those items noted in the audit, he determined that other non-utility items were included in the expense, such as Tampa Bay Lightning and the Tampa Bay Buccaneers events. Witness Schultz also discussed a $1.2 million account in the president's budget center that was not supported by PEF. As noted by OPC, there was no PEF testimony on these amounts. We believe all of the items included by witness Schultz in his adjustment are inappropriate to include in customer rates.

We note that PEF stated that it budgeted $1,208,000 to Salaries and Wages that should have been budgeted to A&G Office Supplies and Expense We agree with this adjustment. This results in an increase to A&G Office Supplies and Expense of $1,208,000 system or $1,097,000 jurisdictional. Accordingly, the adjustment proposed by OPC witness Schultz should be netted with this amount. The effect is a reduction of $1,480,677 system, $1,298,435 jurisdictional. ($1,480,677 x .87692 = $1,298,435). Accordingly, we find that the 2010 A&G Office Supplies and Expenses shall be reduced by $1,298,435 jurisdictional ($1,480,677 system).

L. Productivity Improvements

PEF witness Joyner testified that the $7.7 million variance addressed by OPC witness Schultz is a product of Mr. Schultz's lack of understanding of supporting MFRs and documentation rather than a true variance. Witness Joyner stated that PEF's actual O&M expenditures total $114.4 million for 2008, which represents the sum of the FERC 580 and 590 accounts. He stated that the base year O&M expenses of $114.4 million, multiplied by the 1.1415 compound multiplier yields, the 2010 Test Year Benchmark of $130.6 million. He stated that the variance between the benchmark and the 2010 Adjusted Test year O&M of $144.9 million is $14.3 million. He added that MFR Schedule C-41 provides the explanations for the variances associated with vegetation management, environmental, operational cost efficiencies and re-organization, and FERC account reclassifications. He disagreed with OPC witness Schultz's assertion that there is a $7.7 million unexplained variance.

OPC witness Schultz testified that PEF identified a number of improvements without any explanation as to where the cost savings are reflected. He stated that there is an unsupported FERC 890 cost of $6.9 million and an unidentified distribution increase of $7.7 million. He stated that PEF witness Sorrick indicated a cost savings from the Hines Power Block 4 Combustion Optimization Package in the future, along with a reduction in maintenance costs resulting from the Anclote Cooling Tower project. Witness Schultz stated that there must be some benefit to ratepayers from the significant increase in spending to offset the cost. He asserted that if that cost savings is not reflected then it may flow through to shareholders instead of the ratepayers. He stated that if rates are set based on the significant spending without recognition of the benefits that are forthcoming, when the cost savings occur there is no way for ratepayers to receive that benefit.

OPC witness Schultz testified that the 2009 PEF Strategic Plan shows the Company's strategy commitment in the statement "[t]he overall mission of Progress Energy is to reward its investors by providing above-average total shareholder returns over a continuous timeframe." He stated that the financial objectives include annual EPS growth of 4 to 5 percent, continued dividend growth, and an annual total shareholder return of 8 to 10 percent. He stated that the document indicates that the base rate filing in 2009 will add significantly to the 2010 price. The witness testified that the Company has a strategy of annual productivity gains of at least 3 to 5 percent. OPC argued in its brief that this strategy is exactly the one that was communicated to Wall Street at the same time the case was being filed, but the Company did not include the benefits of these measures in the filing.

OPC witness Schultz testified that the Company looks at difficult economic times from the shareholder perspective. He stated that there is no goal to minimize the rate request and that is substantiated with the business as usual pay increases, increased incentive compensation and the other significant cost increases that are recorded above the line. In contrast, witness Schultz testified that the Company stated that the declining economic condition was the reason that donations and civic expenses were less in the 2010 budget than in 2008. He noted that there was a budget reduction of approximately 20 percent for below the line costs for civic functions and donations that would impact shareholder returns.

OPC witness Schultz recommended a reduction to O&M expense of $13.034 million, by taking PEF's requested 2010 O&M expense net of labor and assuming a 3 percent productivity factor. He stated that 3 percent is the low end of the Company strategy.

Witness Schultz discussed a similar adjustment for Consolidated Edison Company. He testified that the New York Commission determined that because of the increased investment in plant there would be an increase in productivity and ruled that the productivity adjustment should be 2 percent instead of 1 percent. He stated that the New York Commission made an additional adjustment reducing O&M cost by $60 million, which factored in the downturn in the economy and the impact the company's request would have on ratepayers. He stated that Consolidated Edison was ordered to implement austerity programs to constrain costs and tighten belts to limit discretionary spending.

OPC argued that the Company has made no effort to make sure that the MFRs are representative of going-forward expense levels. OPC notes that, at the same time, the Company states that it is targeting budget reductions and undertaking significant belt-tightening efforts. OPC points out that the Company told this Commission that for 2009 there was only a $3.5 million budget cut possibility (with no carry forward to 2010) and minimal belt tightening with no quantification – mainly in the de minimis area of meals and entertainment, conferences and travel. OPC argues that none of the cost containment efforts are reflected in the test year presentation for our consideration. OPC stated that the Company told Wall Street that the Florida operation contributed significant earnings growth in 2008, in line with what should be expected from a utility with major capital expenditures. OPC argues that PEF is willing to take the measures necessary to meet its EPS guidance, even if it means seeking extraordinary relief and cost deferrals and raids on the storm reserve. FIPUG stated that PEF's projected O&M expense should be reduced by $13.034 million to reflect 3 percent annual productivity gains.

OPC witness Schultz notes a number of areas with which he is concerned. Witness Schultz's adjustment seems to be based primarily on the fact that there are variances in O&M expenses above the benchmark. He stated that the additional costs must be offset by a savings to the ratepayer.

We have approved a $9,004,955 jurisdictional reduction for specific items that comprise a portion of the variance. Of the $53,100,000 above the benchmark, $30,300,000 was addressed specifically, and the remainder was also considered. We believe based on our adjustments that the variance of concern to OPC has been addressed.

Of the total $10,300,000 variance, $6,900,00 is due to FERC 890 requirements. We did make an adjustment for the FERC 890 amounts; however, we made a reduction of $1,717,042 for excess vegetation management expense that results from deferred maintenance. An additional $1,000,000 for bonding and grounding was also discussed, with no adjustment. Thus, all but $682,958 of the total variance was specifically addressed.

Similarly, the increase in distribution O&M expense is addressed later in this order. We made an adjustment of $8,924,197, for excess vegetation management expense that results from deferred management. When this adjustment is taken into consideration, the $7,700,000 variance discussed by OPC witness Schultz is eliminated.

We do not believe the fact that there is a variance above the benchmark is sufficient reason to make an adjustment. Moreover, we do not agree that an increase in cost must also have a demonstrable cost savings. It was noted by PEF witnesses, such as witness Sorrick, that improved performance from the maintenance would result in fuel cost savings. Such savings would not be reflected in the MFRs. We believe that PEF has demonstrated that the requested maintenance cost is necessary. Based on the above, we find that adjustments have been made to address the variances in O&M expenses. Therefore, no further adjustments shall be made to PEF's 2010 allowance for O&M expense to reflect productivity improvements.

M. Average Salary Increases

PEF stated that it budgeted $1,208,000 to Salaries and Wages that should have been budgeted to A&G Office Supplies and Expense and $450,000 to Salaries and Wages that should have been budgeted to A&G Injuries and Damages. PEF advised that Salaries and Wages should be reduced by $1,454,000 jurisdictional ($1,658,000 system).

OPC argued that, as demonstrated by OPC witness Schultz, a reduction of $53,831,980 ($47,540,636 on a jurisdictional basis) should be made to compensation expense. AG stated that salaries and benefits should be reduced to the extent that customers testified their salaries and benefits have been reduced.

PEF noted an error of $1,208,000 in Salaries and Wages that should have been budgeted to A&G Office Supplies and Expense and $450,000 to Salaries and Wages that should have been budgeted to A&G Injuries and Damages. We agree with PEF's adjustment of $1,658,000 (system) and $1,454,000 (jurisdictional). Based on the above, we find that the salaries and wages account shall be reduced by $1,454,000 jurisdictional ($1,658,000 system).

N. Average Salaries

PEF uses various survey and market benchmarking tools to make salary comparisons with other companies. The Company provided several compensation studies in response to staff discovery. When questioned about the studies, PEF witness DesChamps replied on cross examination that the documents provided in response to discovery were the actual salaries studies, not simply summaries. He responded that the documents provided are the only support PEF has for its 2010 compensation increases.

PEF witness DesChamps discussed one of the studies, which was also included in Exhibit 213. He explained that the study is used by the Company to assess compensation on an ongoing basis. He described it as compensation ongoing review and evaluation (CORE). He stated that that the Company uses this study to look at 20 to 25 percent of PEF's positions on an ongoing, rolling basis. He testified that the CORE is used to evaluate salaries for non-officer positions.

Witness DesChamps explained that a job value (JV), or market value is based on PEF's surveys of market data, and represents a value of a position that PEF uses to benchmark the position to the general market. He advised that a job value equaled about 7 percent. Witness DesChamps testified that of the 68 PEF job titles with below-market salaries, as shown in the CORE study, 13 were two JVs below market and 55 were one JV below in 2008. He stated that of the 2,100 employees who were the subject of the study, 332 were below market, but none were above market. When asked whether the breakdown of job titles below market was contained in the report; he stated that it was not.

Witness DesChamps stated that the dollar impact of the CORE information that was reflected in PEF's 2010 test year salaries is $39,500. He agreed that there were no other salary increases in the 2010 test year that were supported by the findings of the CORE study.

PEF stated that while it is cognizant and empathetic of the economic conditions facing both PEF and its customers, it must also plan for the long-term future of the Company. PEF argued that it takes a long-term, strategic approach to attracting and retaining its employees. The Company stated that it continuously benchmarks its total compensation plans, including base pay and incentive compensation, to ensure it remains within the 50th percentile of its peer utilities. PEF noted that it uses various survey and market benchmarking tools to make comparisons with other companies. PEF argued that recent survey data shows companies have not eliminated incentive compensation and have started to reverse previous salary freezing decisions made as a result of the economy. PEF stated that it cannot and should not take any short-sighted measures to reduce total compensation, because it risks losing its skilled employees.

OPC witness Schultz testified that PEF's compensation request is excessive and inappropriate. He recommended a reduction of $47,540,636 jurisdictional ($53,831,980 system) to compensation expense. He stated that:

> [t]he Company's request totally ignores the state of the economy and the impact that the request will have on the citizens of Florida who are served by the Company. The request includes business as usual pay increases, an increase in payroll for employees that have not been hired yet and an increase in incentive compensation, when the current amount of incentive compensation is not justified.

OPC witness Schultz testified that a study dated June 17, 2009, indicated that 69 percent of companies surveyed had 2009 budgeted aggregate base pay equal to or below the 2008 budget. He stated that PEF ignored the current economic climate as well as measures it could have taken to curb costs. He advised that other utilities have limited salary increases.[45]

We note that the CORE study provided by PEF is a summary of a larger study. PEF witness DesChamps described the document as such, but on cross-examination stated that the Company provided actual compensation studies in response to discovery. We believe that the information provided by PEF in response to discovery is not all of the documents PEF has that support its salaries. Our staff cross-examined PEF witness DesChamps about the CORE study in particular. Information was provided by witness DesChamps that was not available in the documents, such as a breakdown of job titles below market. Upon examination of the study, there were no specifics as to the names of the employees whose salaries were below market. Only $39,500 of salary increases in the test year were based on the CORE document. PEF provided no other documents to support the salary increases in the test year. It is clear from an examination of the documents provided by PEF that there must be some other documents that were not provided, in spite of PEF's insistence that all were provided. We believe that PEF's salary request is not supported by the record.

OPC witness Schultz testified that the Company budgeted pay increases for non-bargaining positions at 3.75 percent and for bargaining positions at 3 percent in 2009 and 2010. He stated that the actual increase implemented for non-bargaining positions in 2009 was 2 percent for management and 3 percent for non-management positions. He calculated the actual average base pay increase per employee as shown in the MFRs to be 9.4 percent from 2008 to 2010, or 4.7 percent per year.

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[45] E.g., Green Mountain Power in Vermont limited increases in compensation to the contractual rate for bargaining employees, and froze wages for the non-bargaining employees; Potomac Electric Power Company did not request a wage increase for non-bargaining employees, and only asked for a portion of the increase for the bargaining employees; Peoples Gas System eliminated the executive increase and reduced the employees' compensation increases.

OPC witness Schultz testified that the Company was asked whether it had considered the state of the economy with regard to its salary increases. He noted the Company responded that the 3.75 percent budgeted salary increase reflects historical trends and current economic conditions by holding the increase flat at 3.75 percent. Witness Schultz stated that PEF budgeted an increase of 3.5 percent in 2006 and 2007 when the economy was doing well, but increased it to 3.75 percent in 2008. He stated that this behavior is counter to claims by the Company that it is trying to minimize costs.

OPC witness Schultz recommended that the average annual increase in base pay be limited to 2.35 percent, or one-half the 4.7 percent increase as calculated by the witness. He stated that this calculation reduces the average base salary from $75,170 to $71,979 and reduces test year payroll expense by $12,209.439.

We believe that a 2.35 percent increase to base pay is reasonable given the actual 2009 figures of 2 percent for management employees and 3 percent for non-management. As previously noted, we do not believe the Company provided the studies to support the increases. The summary of a study that was provided was the basis for an increase of $39,500 overall for selected employees. Upon review of the evidence, we believe a reduction to payroll expense of $12,209,439 as calculated by OPC witness Schultz is appropriate.

OPC witness Schultz expressed concern that PEF buried the overtime costs in various other MFR schedules rather than show it on MFR Schedule C-35. However, he did not propose an adjustment.

We agree that the overtime is not shown on MFR Schedule C-35. The record is silent as to the reason it is not shown. We examined information provided by the Company that indicates overtime and premium pay were stable, with $35,222,231 for 2006; $43,077,488 for 2007; $43,088,714 for 2008; and $43,455,819 for 2009. The 2010 projected test year amount is $40,860,669, which is lower than the 2007, 2008, and 2009 amounts. Our staff engaged in discussion with PEF witness DesChamps about a limited number of employees that earned large amounts of overtime. The witness stated that the Company has 47 employees in the highly skilled positions that were the subject of the discussion. Although the amount of overtime for certain of the employees is high, the skill level of the position may warrant the overtime that is paid. Further, given the stability of the overtime over recent years, we do not believe an adjustment to overtime is warranted. In addition, PEF witness DesChamps testified that PEF did not include bonuses in the 2010 test year. Accordingly, we find that salaries expense shall be reduced by $10,146,776 jurisdictional ($12,209,439 system) for the 2010 projected test year.

O. Employee Positions

PEF argued that OPC witness Schultz's recommendation that 80 positions be removed from PEF's employee count for 2010 is unsupported by record evidence. PEF stated that the 80 positions represent 26 of 36 proposed new positions not filled as of June 22, 2009; 25 vacant positions; and an allocation of 29 Service Company Full Time Equivalents (FTEs). PEF stated that the need for the positions was explained by PEF's operational witnesses for generation, transmission, and distribution.

PEF argued that OPC witness Schultz did not refute PEF's need for any of the 36 new positions, but recommends taking away 26 positions that were unfilled as of June 22, 2009, simply because they have not been filled yet. PEF stated that this recommendation is not based on any analysis. The Company argued that the proposed reduction improperly assumes that the Company does not plan to fill these positions. PEF stated that witness Schultz has no evidence that PEF is not going to fill these positions other than the fact that they are currently vacant. PEF noted that some of the new positions are not scheduled to be filled until 2010, so they would not be filled in the first half of 2009. The Company argued that it needs these employees and will fill these positions during the remainder of 2009 and 2010.

PEF stated that the 29 Service Company allocated full time employees were supported in PEF's response to OPC's Seventh Set of Interrogatories, No. 299. PEF explained that the additional FTEs is due to an increase in the allocation ratio to PEF driven by an increase in PEF base payroll costs compared to Progress Energy Carolinas (PEC) as a result of the many projects which were explained by PEF's operational witnesses for generation, transmission, and distribution. The Company points to no specific testimony by its witnesses that support the change in allocation.

OPC witness Schultz testified that 497 positions are proposed for addition, while 127 are to be eliminated, for a net of 370 additional employees. He noted the Company's explanation was that 387 positions are clause-related, and 29 positions are allocated headcounts. He stated that the Company appears to believe these positions do not require justification. The witness testified that PEF indicated that only 81 of the 370 positions impacted base rates, consisting of 36 new positions and 45 vacancies. He noted that only 10 of the new positions and 20 of the vacancies had been filled, but as of March 31, 2009, there were additional vacancies. He stated that only 33 of the 36 new positions were referenced in testimony, which means that the other 48 of the 81 positions had no justification. Witness Schultz recommended that 51 unfilled positions be removed, along with the 29 allocated headcount service company positions. He stated that the resulting reduction using his average base salary of $71,979 per employee would be $4,156,891.

OPC witness Schultz testified that he interpolated the projected increase in employees by assuming a level increase month to month. He calculated a vacancy rate of 1.94 percent, which would yield 103 vacant positions of the 5,299 projected positions for 2010. He stated that, based on his assumptions, his recommendation to reduce positions by 80 is conservative.

According to OPC witness Schultz, PEF indicated that only 81 of the 370 positions it has requested impacted base rates, consisting of 36 new positions and 45 vacancies. Witness Schultz pointed out that only 10 of the new positions and 20 of the vacancies had been filled, but as of March 31, 2009, there were additional vacancies. He testified that only 33 of the 36 new positions were referenced in testimony, which means that the other 48 of the 81 positions had no justification.

Witness Schultz also considered the Company's vacancy rate in formulating his adjustment. He based the adjustment on a level increase in employees from month to month. A vacancy rate of 1.94 percent yields 103 vacant positions of the 5,299 projected positions for 2010. Thus, the recommended adjustment of 80 employees is lower than the calculated number.

A reduction of 80 employees using OPC's average base salary of $71,979 per employee yields an adjustment of $4,156,891 system. Using a jurisdictional separations factor of 0.83106, the jurisdictional amount is $3,454,626.

While PEF stated that OPC's adjustment is not based on any analysis, we believe the calculations used by OPC witness Schultz, which are based on record evidence, show that he did perform an analysis of the historical data, including the vacancies and decline in employees.

PEF employees declined from 5,005 in December 2007 to 4,929 in December 2008, to 4911 in March 2009. This is a decrease of 94 employees over a 15-month period. According to OPC witness Schultz, the decrease in employees is evidence that vacancies cannot be ignored, and questioned whether the Company's projected increase in employees is reasonable. We note that the testimony of OPC witness Schultz is unrebutted.

The Company projects an increase in employees to 5,245 in December 2009 and to 5,299 in December 2010. There was an increase in employees from 4,785 in 2006 to 5,005 in 2007, a change of 220, but when offset by the subsequent decline of 94 positions, the net increase over a two-year period was 126. Given the Company's actual numbers, we are not convinced that the Company will add 370 employees from 2008 through the end of 2010. This is almost 3 times the net increase from December 2007 to March 2009.

PEF stated that its operational witnesses explained the need for additional employees. PEF stated that employees would be hired to address the increased scope of transmission work required by NERC standards as PEF witness Oliver discusses in his testimony. Witness Oliver does discuss the NERC standards, but does not mention employees or positions. We have not found any testimony by PEF witnesses to support its request for additional employees.

When asked whether the Company was planning any workforce reductions, PEF witness Dolan testified that the Company's business units are always striving for efficiency which may result in a workforce reduction, but those would be a normal course of business type of reduction. He testified that there is not a broader plan for workforce reductions. It is not clear from his discussion that the Company will add the additional employees. It appears that a reduction in employees is as possible as an increase.

We believe any company can expect a certain number of unfilled positions at any given time. We believe that the calculation provided by OPC witness Schultz is based on sound reasoning. Based on the above, we find that employee positions for 2010 shall be reduced by 80 positions for a dollar reduction of $4,156,891 (system) or $3,454,626 (jurisdictional).

P. Incentive Compensation

PEF witness DesChamps explained the Company's four incentive compensation plans.

- The Employee Cash Incentive Plan (EICP) – an annual short-term cash incentive award for achievement of strategic company and business goals. It is designed to ensure a close link between pay and performance and to share the company's financial success with the employees who make it happen. Based on EPS and ten strategic goals by business unit, such as safety, budget adherence, electric service reliability, plant production and efficiency, and other similar goals on a yearly basis. The plan has a CEO discretion component. The EPS component and the ten operational goals have equal weighting.

- The Management Incentive Compensation Plan (MICP) – provides annual incentive opportunities to executives, managers, and supervisors to promote achievement of annual performance objectives, based on desired corporate financial and operational objectives.

- The Executive Incentive Plan (EIP) – an umbrella plan for senior executive officers designed to preserve tax deductibility of incentive awards.

- The Long-Term Incentive plan – provides equity awards to managers and executives, based on sustained achievement of financial and operational goals.

PEF witness DesChamps stated that the plans aid in attracting, retaining, and rewarding managers and executives. He testified that PEF's compensation program is market- based at the 50th percentile within national, regional, and local comparative markets. He stated that incentive compensation is an integral part of the total compensation package. He explained that when the Company benchmarks jobs with similar peer utilities, it does so with the value of the total compensation package.

PEF witness DesChamps testified that maintaining a financially strong company benefits customers as well as shareholders. He stated that a financially strong company can access capital more easily at a lower cost, which benefits customers by lowering rates. He contended that the fact that the Company's shareholders also benefit from these incentive compensation goals is irrelevant to whether the costs of the incentive compensation plans should be included in base rates.

PEF witness DesChamps contended that elimination of incentive compensation would cause PEF to increase its base pay to compete with other utilities and industries on total compensation basis for the workforce it needs. He testified that the Company would lose the flexibility to adjust compensation based on performance.

OPC witness Schultz testified that incentive compensation is in addition to base pay that can only be justified if the performance of employees results in improved customer service, customer reliability, and improved financial results. He asserted that the improvements benefit both ratepayers and shareholders, and the cost for incentives should follow the benefit. He explained that improvements to profits, without improvements to service and reliability, should be borne by the shareholders. He stated that it should not be assumed that incentive compensation is a required part of a compensation package that should automatically be passed through to the ratepayers. He noted that the Company expressed unwillingness to remove the cost of incentive compensation from its request.

OPC witness Schultz advised that a number of jurisdictions either limit or disallow incentive compensation in rates. He identified several jurisdictions that have disallowed some portion of incentive compensation.[46] He advised that incentive compensation was totally disallowed in the Vermont Green Mountain Power case. He further stated that in Arizona, stock based incentive compensation is generally excluded and cash-based incentives are shared between ratepayers and shareholders.

OPC witness Schultz expressed concern with the incentive compensation plans themselves. He noted that the stated purpose of the Management Incentive Compensation Plan (MICP) was to promote the financial interests of the Company. He stated that the emphasis is on financial performance, which benefits shareholders. Witness Schultz noted that there was no reference to ratepayers in the incentive compensation plans.

OPC witness Schultz stated that the incentive compensation plan is based on goals that do not require above average performance. He asserted that some of the operational goals may not be real goals. He noted that goals may be relaxed when they are missed, such as a goal of less than 1.25 recordable injuries that was not achieved in 2006. He added that the goal was relaxed in 2007 to less than 1.37 recordable injuries. He testified that the transmission goal for System Average Interruption Index (SAIDI) of less than or equal to 9.3 was not achieved in 2006. He added that even though the reduced goal of 9.48 was met in 2007, it was reset in 2008 to 10.2, thus lowering the performance requirement. He stated that the Sarbannes-Oxley goal of no material weakness in internal controls is an expected duty that should fall under base pay. He asserted that even though PEF witness David Sorrick stated that it is the Company's goal to have zero accidents, the incentive compensation goals allow for accidents. Finally, he stated that while the environmental goal of greater than or equal to 4 was achieved in 2005, 2006, 2007, and 2008, the goal has not been raised. Witness Schultz opined that the term "incentive" means to stimulate; there is no stimulation if goals are not increased.

OPC witness Schultz recommended that $25,371,639 of incentive compensation and $12,094,011 of long-term incentive compensation expense be disallowed in its entirety He based the recommendation on the failure of the Company to establish a plan that is designed to provide a tangible and/or quantifiable benefit to ratepayers. He opined that it is insensitive to ratepayers to allow in rates added compensation with dubious demonstrable benefits.

OPC witness Schultz and FIPUG witness Marz each addressed this issue in different ways. Witness Schultz based his recommendation on total incentive compensation. Witness Schultz recommended that incentive compensation of $25,371,639 and $12,094,011 of long-term incentive compensation be excluded from base rates, based on the expense ratio he calculated.

On the other hand, FIPUG witness Marz based his recommended adjustment on the Incentive Compensation Plan on PEF's MFR Schedule C-35, but did not address the Long-Term Incentive Compensation Plan on the next line. Witness Marz recommended that all of the Company's incentive compensation budgeted for executives and senior management, as well as

[46] Examples of jurisdictions that have disallowed a portion of incentive compensation include New York and Washington, D.C.

50 percent of the incentive compensation for management and non-management employees, be excluded from the Company's rate request. While the reduction to incentive compensation was intensely argued by the Company, witness Marz's use of 50 percent to represent the non-EPS portion of incentive compensation is unrebutted.

FIPUG argued that all of the compensation paid to executives under the EIP and the Performance Sub-Share Plan should be excluded from the calculation of operating expenses and rates. We believe the Performance Sub-Share Plan referred to by FIPUG is a Long-Term Incentive Plan. As previously noted, FIPUG witness Marz did not address the Long-Term portion.

The Company's proxy statement shows certain categories of incentive compensation have a primary purpose to "align interests of shareholders and management, and aid in attracting and retaining executives." In particular, the Long-term Incentives – Performance Shares and the Long-term Incentives – Restricted Stock/Restricted Stock Units both share that primary purpose. Staff notes that the long-term incentives are equity-based compensation plans.

PEF witness DesChamps compared PEF to the recent TECO case in which we excluded that portion of TECO's incentive compensation tied to the financial goals of its parent, TECO Energy.[47] According to witness DesChamps, Progress Energy can be distinguished from TECO Energy, even though it is an industry peer. He explained that TECO has a number of non-regulated subsidiaries upon which its financial performance is based, while PEI receives revenue primarily from its two electric utility subsidiaries, not from non-regulated subsidiaries.

As explained by PEF witness DesChamps, a portion of the incentive compensation goals are tied specifically to PEF performance, while only the goals based on EPS are tied to PEI. He discussed a table in the Company's proxy statement with a column showing compensation based on company earnings per share. The witness explained that there is a target opportunity for executives to receive a level of compensation based on company earnings per share. He explained that for William Johnson, 100 percent of the target opportunity for Mr. Johnson's annual incentive compensation is based on the company earnings per share measure. He stated that the measure applied to each of the officers listed in the proxy statement table. The Company's proxy statement shows that executive incentive compensation is based on company earnings per share.

We are concerned that the Company has placed an emphasis on EPS that has negative consequences, in particular, the deferral of certain items of maintenance. For example, PEF witness Oliver testified that PEF's focus for transmission vegetation management in 2007, 2008, and 2009 was on lines greater than 200kV to avoid significant penalties. PEF witness Oliver explained that funding was shifted from lines not subject to the penalties to those that were. Lower voltage lines were cleared on an "as needed" basis, but were not cleared to the full extent that would normally be performed during cycle clearing. He stated that additional funds are

[47] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 71.

needed now for clearing of the lower voltage lines that are not subject to the $1 million per day penalties.

According to PEF witness Joyner, distribution vegetation management has been prioritized based upon expected impact to system performance, and to yield the maximum benefit for the money spent. He indicated that our storm hardening rule required an increased scope of work, but it did not provide the additional maintenance dollars above the amount received in the Company's 2005 rate case settlement that are necessary to perform the work. We believe that the Company limited the amount of money it spent on vegetation management to avoid spending the requisite dollars.

We believe both of these instances demonstrate a concern for EPS above that of conducting appropriate maintenance where it might impact Company earnings. We do not believe employees should be rewarded for that. Accordingly, we believe that incentive compensation tied to EPS should not be passed on to ratepayers.

OPC witness Schultz questions whether incentive compensation is a significant factor in attracting and retaining competent employees. He stated that the top five drivers used by an employee to choose an employer were competitive base pay, competitive health care benefits, vacation/paid time off, competitive retirement benefits, and career advancement opportunities. He noted that incentive compensation was not included in the top five, nor was it even in the top ten attraction drivers.

PEF witness DesChamps stated that OPC witness Schultz did not analyze whether the utilities in PEF's studies are allowed to include incentive compensation in the rates charged to customers. Witness DesChamps stated it was not possible to ascertain whether adjustments had been made, because individuality of the data was confidential. OPC witness Schultz stated that no salary study he has reviewed over the past 30 years indicated that salary levels within a study had been adjusted to reflect disallowed incentive compensation.

PEF witness DesChamps testified that OPC witness Schultz did not perform a specific analysis as to PEF's particular studies, nor did witness Schultz analyze whether a particular peer utility in a study skewed the results of the study.

PEF witness DesChamps stated that PEF provided all studies it had that supported its compensation levels. On cross-examination, information was provided by the witness that was not available in the salary documents provided by PEF. Further, there were no specifics as to the job titles that were impacted or the names of the employees in the Company's CORE document, which shows that there must be some other document that was not provided in response to our staff's request. We question whether the actual studies were made available for an analysis to be performed.

Witness DesChamps noted that Florida has recognized the value of incentive compensation plans in the past, and has approved their inclusion in rates. We note that the decisions discussed by the witness were based on the record in those cases. While prior decisions are important, the decision in this case must be based on this record, which may be different from that considered previously. There is extensive testimony from several PEF witnesses as well as intervenors. In addition, cases in other jurisdictions may be instructive, but those decisions are not the driving factor for a decision in Florida. The utility has the burden of proof to show that recovery for these plans is appropriate in this case.

OPC witness Schultz testified that PEF's incentive compensation goals do not require above average performance and may be relaxed when they are missed. He expressed doubt that the operational goals are real goals. In particular, witness Schultz testified that 99.6 percent of all eligible employees received incentive compensation in 2006, while in both 2007 and 2008, 99.7 percent of eligible employees received the awards. He stated that with approximately 5,000 employees, he found it very hard to believe that performance was so high among the employees that almost everyone earned a payment. He opined that this is evidence that the incentive compensation is just added compensation, not a true incentive compensation.

PEF witness Oliver stated that witness Schultz is making apples-to-oranges comparisons with the goals. He explained that some of the changes in goals noted by witness Schultz were based on PEF and PEC together at one point, then later separated. He also stated that witness Schultz compared different types of SAIDI as if they were the same.

PEF witness Sorrick addressed two specific types of goals based on safety and environmental compliance. He stated that PEF's ECIP/MICP safety goals are set at levels to drive the actual safety performance of the work crews to top decile performance when compared to peer utilities. He explained that compliance in environmental performance is the minimum acceptable standard for all employees in the generation unit. He stated that a sustained goal of 4.0 (on a scale of 0-5) on the EI index is indicative of top-tier performance that should be rewarded with incentives.

We believe that incentive compensation provides no benefit to the ratepayers and constitutes nothing more than added compensation to employees. Especially in light of today's economic climate, we believe that PEF should pay the entire cost of incentive compensation, as its customers do not receive a significant benefit from it. Accordingly, we find that the 2010 allowance for incentive compensation shall be reduced by $32,854,378 jurisdictional ($37,465,650 system).

Q. Employee Benefit Expense

PEF witness DesChamps testified that OPC witness Schultz recommended an adjustment to the Company's requested average benefit per employee expense by reducing the number of employee positions. He stated that witness Schultz also made an adjustment based on changes to the Company's MFR Schedule C-35. He noted that witness Schultz made some observations about PEF's health care costs and retirement plans, but did not make any specific adjustments.

PEF witness DesChamps stated that OPC witness Schultz did not do any specific analysis of the Company's health care costs. Pointing to a statement by witness Schultz that PEF's employee contributions increased by 3 percent, while healthcare costs have been increasing 10 to 12 percent annually, witness DesChamps contended that witness Schultz has taken data from

PEF's interrogatory response out of context. He explained that the 3 percent figure is for bargaining unit plans only and only reflects the increase from 2008 to 2009. He testified that witness Schultz did not acknowledge the Company's benefit strategy, which includes the introduction of consumer-driven health plans, and action taken to limit its health care cost increases per employee to well below the national average over the past several years. Witness DesChamps asserted that although cost increases have fluctuated from year to year, the costs still remain below the national average, as reflected in Exhibit 215. He contended that witness Schultz does not analyze what employee contributions should be, nor does he assess whether increasing employee contributions would limit the Company's healthcare cost increases.

PEF witness DesChamps stated that witness Schultz's reference to the 10 to 12 percent annual increase in health care costs is based on the Company's budget projections, which are based in part on national trends. He explained that employee contributions are set based upon review of prior year's experience as compared to projections for the next year. He stated that, to the extent the prior year's actual claims experience is less than the budget projection, employee contributions will not relate directly to the corresponding budget projection. He opined that the Company must consider its need to remain competitive with other utilities and other large employers when setting employee rates.

PEF witness DesChamps noted that OPC witness Schultz did not do any specific analysis as to the costs for the Company's retirement plans. He stated that witness Schultz made statements that the Company has a generous benefit package, while many of PEF's customers do not enjoy similar benefits. He testified that the Company's benefits packages are part of a carefully designed and benchmarked total compensation package. He stated that PEF is competing against other utilities, as well as non-regulated companies, for highly skilled employees. He explained that an employee may choose better health or pension benefits over a higher salary. He advised that, if a significant piece of the overall compensation package, such as pension or incentive compensation, is eliminated, other portions of the total rewards package may require increases. He testified that this Commission recognized the value of a total compensation approach in Gulf's 2002 rate case proceeding.[48] PEF witness DesChamps asserted that the Company's total compensation package, and all the expenses included in this rate case for the package, should be approved as reasonable.

OPC witness Schultz testified that an adjustment should be made based on his recommended adjustment to the number of employees. He explained that the adjustment was made using the average benefit expense per employee multiplied by his recommended adjustment of 80 positions, which resulted in an adjustment of $1,946,206. OPC stated in its brief that this adjustment was not rebutted by the Company.

In addition, OPC witness Schultz testified that pension cost increases of $67,472,819 and medical cost increases of $7,071,527 have driven an increase in fringe benefit costs. He noted that the Company projected an increase of $79,676,684 in fringe benefit costs from $95,825,556 in the 2008 base year to $175,502,240 in the 2010 projected test year. He testified that the

[48] Order No. PSC-02-0787-FOF-EI, issued October 22, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.

pension cost increase is due to a significant downturn in the economy. He argued that the healthcare costs appeared excessive due to the fact that employee sharing has not kept pace with the cost increases the Company has projected. He noted that the employee contributions increased by 3 percent, while health care costs were rising at a rate of 10 to 12 percent annually.

OPC witness Schultz noted that PEF has a wide array of benefits that include two pension plans. He stated that having two retirement plans is a luxury that most ratepayers do not have. He noted that the Company also has generous health care plans that include general health, pre-tax health savings, dental and vision care, miscellaneous benefits and retiree benefits that are paid for by the ratepayers. He stated that ratepayers may be uninsured and may not have a retirement plan. He testified that we should factor this into its decision given today's economic climate.

We agree with OPC witness Schultz that fringe benefit expense should be reduced consistent with the reduction of 80 employee positions previously addressed. Thus, we also agree that an adjustment of $1,946,206 should be made to reflect the reduction in positions.

The basis for OPC witness Schultz's second adjustment regarding the discrepancy in the revised MFR Schedule C-35 is based on the fact that the revised schedule shows a lower amount of fringe benefit expense than the original filing. We note that the total expense numbers for all O&M expenses are the same as the original filing. The discrepancy pointed to by witness Schultz is a recategorization of certain expenses. However, there is no impact on the Company's overall rate request. Therefore, we do not believe a reduction should be made.

Finally, OPC discusses the Company's medical and pension benefits, but does not recommend a specific adjustment. There is no evidence in the record that the fringe benefits are unreasonable as compared to other companies. PEF witness DesChamps testified that health care cost increases per employee have been well below the national average over the past several years. Thus, we do not believe a reduction other than that previously discussed should be made.

Based on the above, we find that the proposed 2010 allowance for employee benefit expense be reduced by $1,706,667 jurisdictional ($1,946,206 system) to reflect a reduction in employee positions.

R. Accrual for Property Damage

As part of our decision, we discontinued storm damage accrual for the Company. Therefore, for the 2010 projected test year, the annual accrual for property damage shall be reduced by $14,922,000 ($16 million system).

S. Generation O&M Expense

PEF witness Sorrick testified that OPC witness Schultz's assertion that PEF's power operations O&M expense request appears excessive demonstrates his fundamental lack of understanding of PEF's O&M cost requirements. Witness Sorrick stated that the maintenance requirements included in the 2010 budget are driven by actual unit operations over the past few years and the projected operations for 2009 and 2010. He disagreed with witness Schultz's assertion that the rate request set forth for 2010 is based upon a high year, stating that it is an uninformed assertion. Witness Sorrick stated that the major maintenance costs do fluctuate from year to year, and that the Company tries to levelize the maintenance requirements within reason. Witness Sorrick testified that it is not always possible to levelize the maintenance requirements due to the number of units within the fleet, the operational characteristics of each unit, and each unit's position in its given maintenance cycle.

PEF witness Sorrick disagreed with OPC witness Schultz that PEF's power operation maintenance costs are not supported by the Company's MFRs, testimony, or discovery responses. He stated that PEF has described the nature of the planned expenditures and has shown that the need for these expenditures is driven by actual unit operations, which are in turn driven by demand for the Company's product. He added that unit operations over several years accumulate to trigger major maintenance requirements. He testified that PEF has supported its maintenance costs by demonstrating this process.

OPC witness Schultz stated that the Company's request appears excessive. He testified that there was a limited amount of specifics regarding what the figures included. He explained that the Power Operations O&M expense is $175 million after payroll taxes, employee benefits, and injuries and damages. He stated that the real budget total is $201 million. He contended that PEF witness Sorrick's generic explanation of the benchmark variance of $53.1 million is not adequate justification for the $175 million identified by witness Sorrick.

OPC witness Schultz explained that maintenance expense can fluctuate from year to year, making it inappropriate to base the rate request on one higher year. He stated that the maintenance expense is projected to increase $19 million or 35 percent from $54 million in 2008 to $73 million in 2010, excluding company labor. He testified that an adjustment is required to smooth out the cost to the ratepayers.

OPC argued that a fallacy in the Company's case is that the selection of a number of projects that add up exactly to the amount of the overage does not constitute justification or even true explanation of the reason for the overage. OPC argued that PEF's testimony does not provide an adequate explanation and it does not justify the cost increase requested. OPC noted that witness Sorrick admitted on the stand that overhaul expense for planned and unplanned outages, projected to be $53 million in 2010, was more than double the amount of any of the previous 4 years. OPC argued that there was no testimony whether the expense would stay at that level beyond the test year.

OPC stated that PEF witness Sorrick admitted that the activities that were listed in MFR C-41, totaling $53.1 million in excess of the benchmark, were not intended to be comparisons to the same activities in the 2006 base year. OPC argued that the explanations in the MFR Schedule do not constitute justification of the numbers.

OPC recommended a total reduction of $21,650,000 system, $17,741,309 jurisdictional to PEF's 2010 generation O&M expense. The reduction is comprised of three adjustments: $12 million for Clean Air Equipment at CR4, $2.3 million for one-half of the LTSA contract, and $7.35 to smooth out the cost of generation maintenance to the ratepayers.

First, OPC witness Schultz spreads a $15.1 million cost associated with the adaptation of Clean Air Equipment at Crystal River Unit 4 (CR4) over five years. Although his recommended adjustment was based on 5 years, he stated that he believes such work is typically done every nine years. The recommended treatment reduces the 2010 cost by $12 million.

According to PEF, major maintenance must be done on an interval basis for the fossil steam fleet, the combined cycle fleet, and the simple cycle combustion turbine fleet. Considering the C4 outage in isolation does not account for the major maintenance requirements for the entire fleet. It is important to minimize outages on base loaded units in order to minimize fuel costs to the customer.

We believe that customers will benefit from the combined outage. Further, as described by PEF witness Sorrick, this type of maintenance is performed on an ongoing basis for the entire fleet, even though it might only occur at intervals for a specific unit. There is record evidence that customers benefit through reduced fuel costs. Accordingly, we do not recommend an adjustment for this item.

The second specific area discussed by OPC witness Schultz is the $4.6 million cost estimate for 2010 under the LTSA. The basis for witness Schultz's adjustment is that the cost is only an estimate and is not supported. Additionally, because it is an infrequent cost, he is recommending that half be allowed in rates, resulting in a reduction of $2.3 million.

The $4.6 million cost estimate for the Bartow LTSA is based upon a contract with Siemens Power Corporation. We believe that sufficient information has been provided by PEF to support this cost. Moreover, according to PEF witness Sorrick's calculations, the units are actually expected to run an average of 5,900 hours over the next 3 years, which equates to a maintenance frequency of every 2.1 years, not every 6 years as witness Schultz stated in his testimony.

We believe the cost for the LTSA is reasonable. The Bartow facility has four combustion turbines. We believe that OPC witness Schultz's calculation showing the maintenance to be performed every 6 years is in error. Maintenance will occur every 2.1 years. Thus, two units will be inspected each year. The cost includes inspection of two of the combustion units. Therefore, the LTSA cost is appropriate.

The third item witness Schultz addressed is a $14.7 million increase for existing fleet maintenance. He stated that this item also was unsupported, except by the statement in MFR Schedule C-41, and a summary listing of the cost estimate. He testified that the summary of the cost shows that the 2010 projections contain an overloading of maintenance expense. His recommended adjustment was to reduce the $14.7 million by one half, or by $7.35 million, to smooth out the effect on the ratepayers.

PEF provided documentation for the $14.7 million increase for existing fleet maintenance in a number of documents. PEF witness Sorrick testified that the proposal of OPC witness Schultz to reduce power operations maintenance by $7.35 million to smooth out the costs being charged to the ratepayers would require the deferral or cancellation of required maintenance into future years. He testified that to suggest a reduction of this nature and to ignore the physical requirements of the equipment does not make good engineering sense, nor does it adhere to sound maintenance practices of performing the work needed on critical equipment prior to failure.

Preliminary budget information for 2011 and 2012 shows that the Company expects to spend about $177 million and $180 million, respectively, for power generation O&M. PEF argued that, contrary to intervenors' assertions, the O&M request for the 2010 test year of $175 million is not inappropriately high or overstated.

The basis for the OPC adjustment is that the costs are not supported. We agree with PEF that the maintenance costs are supported by the record. The costs are ongoing in nature. We believe costs to the ratepayers should be minimized wherever possible, but not at the cost of deferring necessary maintenance.

The specific items identified account for $30.3 million of the variance above the benchmark. We believe that the benchmark is not a hard ceiling that cannot be exceeded. OPC witness Schultz recommends his adjustment essentially because the amount exceeds the benchmark, but witness Schultz does not take into consideration the necessity for the maintenance or the benefits to the ratepayers, such as reduced fuel costs. Although we agree it is important to smooth costs to ratepayers for non-recurring items, we believe the costs are supported by record evidence. Accordingly, we do not approve further adjustments.

OPC witness Schultz also expressed concern with a $5.3 million precipitator, which he stated is a capital cost, not an expense. However, he did not recommend an adjustment for this item.

PEF witness Sorrick testified that the clean air equipment at CR4 includes $5.3 million for a precipitator that has changed somewhat based upon the latest condition assessment information. He stated that only $1.1 million of the $5.3 million total work to be performed on the precipitator will be expensed, with the balance to be capitalized. Given PEF's statement that there has been a change in this item, we believe it is appropriate to make an adjustment.

FIPUG witness Marz noted a $5.3 million increase for emerging equipment issues and other repairs. He testified that his conclusion was that this amount was a contingency put in to preserve options. He stated that in response to OPC's Sixth Set of Interrogatories, No. 260, PEF stated that the money would be used for forced outage repairs or to enhance the fleet.

PEF witness Sorrick addressed witness Marz's concern with respect to the $5.3 million in emerging equipment costs and other items. He explained that "the purpose of this funding is to address both emergent issues that most certainly will occur as well as opportunity projects with the goal of allowing budgeted funding to be used where it was originally intended." He testified that it was unfair to refer to it as a contingency expense because PEF's experience with fleet operation indicates that this funding has been used most efficiently on the smaller projects and emergent projects.

We agree with FIPUG witness Marz that this is a contingency expense. The Company has no specific maintenance or plant increases associated with this money. Its purpose is to spend it on whatever comes up, as the Company sees fit. There is no evidence that anything will arise in the test year. We believe, given the large increase in generation maintenance expense in the test year, ratepayers should not be asked to also pay for something that may or may not arise in the future. While there may be some cost in the future, it may well be offset by a decrease in the cost of other items.

We find it is appropriate that the $5.3 million in emerging equipment costs be removed. This results in an O&M reduction of $5,300,000 system, $5,023,817 jurisdictional.

FIPUG witness Marz stated that PEF witness Sorrick identified an accelerated outage at CR4, for major boiler and turbine maintenance that will cost $9.3 million. He testified that this one item accounts for 28 percent of the projected increase in steam generation maintenance costs. He stated that the outage was not originally scheduled for the test year, but was moved up from a date beyond the test year. Witness Marz noted that this type of outage occurs every nine years, as acknowledged by PEF. As a result, he stated that the full cost should not be included in rates. He testified that inclusion of the full amount treats it as if it occurs every year instead of every nine years. He stated that only 11.1 percent or one-ninth should be recognized for ratemaking purposes.

FIPUG witness Marz recommended a $15 million reduction to Steam and other Generation maintenance expense. He testified that this is a 50 percent reduction in PEF's projected increase from 2010 over 2009. He stated that even with the reduction, the increase would still be 17 percent above the 2009 budget. His adjustments were included in Exhibit 183. FIPUG witness Marz also testified that the maintenance occurs only once every nine years. He recommended that one-ninth of the amount be allowed in the test year.

Although FIPUG witness Marz addressed two specific areas of concern, the CR4 maintenance and the emerging equipment costs, his adjustment does not appear to reflect his recommended adjustments for CR4 maintenance or emerging equipment. Witness Marz recommended a $15 million reduction to Steam and other Generation maintenance expense. This is based on approximately 50 percent of the budget increase for 2010 over 2009 for Steam and Other Generation, which excluded nuclear.

As discussed above, the specific items identified and addressed in this issue account for $30.3 million of the variance above the benchmark. FIPUG witness Marz based his adjustment, not on the items he addresses in testimony, but solely on the fact that the maintenance expense increased in 2010 over 2009. We find that no further adjustments for generation O&M expense are needed.

The total adjustments are as follows:

Jurisdictional Increase/(Decrease)	Plant in Service	Accumulated Depreciation	O&M Expense	Depreciation Expense
Emerging Equipment			($5,023,817)	
Precipitator	$3,479,776	$19,706	($3,981,138)	$41,680
TOTAL	$3,479,776	$19,706	($9,004,955)	$41,680

Accordingly, we find that Plant in Service shall be increased by $3,479,776 jurisdictional, Accumulated Depreciation shall be increased by $19,706 jurisdictional, O&M expense shall be decreased by $9,004,955 jurisdictional, and depreciation expense shall be increased by $41,680 jurisdictional.

T. Transmission O&M Expense

There is a total increase of $10.3 million in transmission O&M expenses for 2010. The increase is comprised of three different areas, net of a $0.35 million decrease to other transmission items. Those areas are vegetation management, the added costs of FERC Order 890, and PEF's line bonding and grounding program.

PEF witness Oliver testified that approximately $6.9 million of the $10.3 million increase in transmission O&M expenses for 2010 relates to the FERC Order 890's requirement to provide credits to transmission customers under the Open Access Transmission Tariff (OATT) for customer-owned integrated transmission facilities. He stated that PEF must incur new costs to comply with FERC Order 890, and that the costs are recurring, incremental costs beyond PEF's control. He stated that expenses for customer credits associated with this compliance requirement are being budgeted for the first time in 2010. Witness Oliver explained that customers expected to be eligible for credits have contracts for service, but will not actually be taking service under PEF's OATT until late 2009.

As noted by PEF witness Oliver, a company can incur up to $1 million per day in penalties for violations of the 2005 Energy Policy Act on transmission lines greater than 200kV. As a result, PEF's focus of transmission vegetation management in 2007, 2008, and 2009 was on lines greater than 200kV to ensure compliance with the standard and to avoid significant penalties. Funding was shifted from lines not subject to the penalties to those that were, while lower voltage lines were not cleared to the full extent that would normally be performed during cycle clearing. He explained that the increase in vegetation management funding is needed for cycle clearing on lines less than 200kV.

OPC witness Schultz testified that he had a general concerns with the significant increase in the budgeted dollars. He stated that, based on the Company's MFR Schedule C-4, the costs for transmission O&M increased from $31.3 million in 2005 to $35.2 million in 2008. He stated that the 2009 budgeted cost is $35.1 million, but in 2010, the cost increased by $10.3 million to a total of $45.3 million. He expressed concern with three areas: an increase of $6.9 million for added costs of FERC Order 890, an increase of $1 million for a line bonding and grounding program, and an increase of $2.7 million for vegetation management.

OPC witness Schultz stated that the cost for vegetation management was $6.3 million in 2006, $6.9 million in 2007, $5.9 million in 2008 and budgeted at $6.6 million for 2009. He noted that the cost in the projected test year is $9.3 million. Witness Schultz testified that the amount in the test year is excessive when compared to prior years and the 2009 budget. He stated that the increase in the tree trimming budget would have occurred in 2009 if it had been a requirement by this Commission. He concluded that the 2010 increase is not justified.

OPC witness Schultz made an adjustment of $1,717,043 jurisdictional for vegetative management. He stated that the adjustment assumes that the trimming will continue at the same level that the Company performed from 2006 through 2009. He testified that the Company's explanation that the additional trimming is required to comply with FERC and our standard does not support the requested increase. He stated that there is no indication that the historical spending level was insufficient.

FIPUG witness Marz testified that FERC Account 571 is used for recording of expenses for maintenance of overhead transmission lines, including tree trimming and vegetation removal. He stated that the test year included $11.8 million for this account. Witness Marz testified that Account 571 costs increased by $3.8 million or 47 percent from 2009 to 2010 and are $44.5 million or 62 percent higher than the 2006-2009 average expenses. He recommended a reduction of $3.75 million, resulting in adjusted expenses of $8.05 million.

FIPUG witness Marz testified that tree trimming and vegetation management are not new undertakings, but date back to 2006 when a vegetation management program was established.[49] He stated that PEF had already implemented an integrated vegetation management (IVM) program by 2006 that was approved later that year. He added that the Commission approved the Company's storm hardening plan in 2007.[50] Witness Marz stated that the IVM program and storm hardening began well before 2010. He stated that any increase in costs necessitated by the IVM program should have been reflected in costs as far back as 2006. He testified that MFR Schedule C-6 reflects a substantial increase in maintenance of overhead lines beginning in 2007.

The intervenor witnesses have differing amounts for the adjustment. Witness Schultz's adjustment is based on allowing an increase to the 2009 budget amount of $6,554,550 to $6,750,000 for 2010. This results in a decrease of $2,550,000 system, or $1,717,042 jurisdictional. On the other hand, FIPUG witness Marz reduced the 571 account by the entire amount of increase from 2009 to 2010. FIPUG's adjustment of $3.75 million is greater than the amount of the vegetation management increase of $2.75 million noted by PEF witness Oliver. Witness Marz based his reduction on the entire increase of Account 571 from 2009 to 2010, recommending that the entire increase be removed, not just the amount associated with vegetation management.

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[49] Order No. PSC-06-0947-PAA-EI, in Docket No. 060198-EI, issued November 13, 2006, In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.
[50] Order No. PSC-07-1021-FOF-EI, in Docket No. 070288-EI, issued December 2007, In re: Review of 2007 Electric Infrastructure Storm Hardening Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Progress Energy Florida, Inc.

Vegetation management is not a new requirement. The vegetation management program was implemented in 2006, and storm hardening was implemented in 2007, both well before 2010. Witness Marz recommended a reduction of $3.75 million for 2010 to the transmission O&M expense.

We agree with the intervenor witnesses that increases in vegetation management costs are not due to new requirements. The testimony of PEF's witness Oliver leads us to the conclusion that certain line clearing was deferred in favor of clearing those lines that would potentially cause the Company to incur a substantial penalty. As pointed out by OPC witness Schultz, vegetation management costs were less in 2008 than 2006. We believe PEF should have spent more in prior years on the tree trimming. PEF is now requesting additional funds to catch up.

We believe that OPC witness Schultz's adjustment is based on record evidence as to the budget associated with vegetation management. Also, we believe that the Company deferred maintenance on the lower voltage lines, as discussed by PEF witness Oliver. The ratepayers should not have to pay to catch up on that maintenance. Accordingly, a reduction to transmission O&M expense of $1,717,042 jurisdictional for vegetation management expense is appropriate.

PEF included an additional $6.9 million for FERC Order 890 costs, a new item that has not been budgeted for in the past. As noted by PEF witness Oliver, the additional cost arises from a requirement that the Company provide customer credits under its OATT, something that PEF has not previously had to provide. OPC witness Schultz testified that the FERC 890 expense is not based on historical costs. However, he did not recommend an adjustment as part of this issue.

We do not believe an adjustment is warranted, and none is being approved herein. PEF's witness explained that the cost is new, so OPC witness Schultz is correct that it is not based on historical costs. We believe that is not a reason to deny a requested expense. Accordingly, no adjustment for expenses related to FERC 890 is needed.

The final area is the line bonding and grounding program. PEF requested a $1 million increase for this program. The record evidence shows that the program is necessary due in part to the to high volume of lightning strikes in PEF's area, and is an effective way to mitigate storm-related outages. It is a continuing part of PEF's routine line maintenance. The increased funding is necessary to improve line performance on targeted lines. Bonding and grounding is labor intensive as it requires working on one pole at a time, and takes years to complete.

OPC witness Schultz also made an adjustment of $338,145 jurisdictional ($500,000 x .67629) to normalize the line bonding and grounding expense, by spreading it over a two-year period. He stated that bonding and grounding expense does not appear to be an annual cost and the adjustment reflects an expense that occurs every other year. Witness Schultz did not recommend an adjustment for FERC 890 expense.

Witness Schultz does not disagree with the necessity for line bonding and grounding. His adjustment is based on his belief that it is not an annual expense. PEF's witness explained the need for the program and the fact that it will be ongoing for a number of years. We believe this is a cost that benefits ratepayers through increased system reliability as explained by witness Oliver. Accordingly, no adjustment to the line bonding and grounding portion of the increase in transmission O&M expense is needed.

Based on the above, we find that a reduction of $1,717,042 jurisdictional shall be made to transmission O&M expense for vegetation management expense. We further find that no adjustment shall be made for expenses related to FERC 890, or for line bonding and grounding.

U. Distribution O&M Expense

According to PEF witness Joyner, vegetation management has been prioritized based upon the expected impact to system performance, and to yield the maximum benefit for the money spent. He indicated that our storm hardening rule required an increased scope of work, but our rule did not provide the additional maintenance dollars above the amount received in the Company's 2005 rate case settlement. We believe that the Company has limited the amount of money it has spent on vegetation management since it did not receive the requisite dollars.

FIPUG witness Marz testified that storm hardening is not a new undertaking, but dates back to 2006 when a vegetation management program was established. According to witness Marz, PEF's vegetation management program was approved in 2006, and its storm hardening plan was approved in 2007. We agree with FIPUG witness Marz that vegetation management is not a new requirement. As a result, we believe increases in tree trimming should have occurred well before 2010 and to a greater extent than that indicated by PEF witness Joyner.

Witness Marz's $13.9 reduction in distribution O&M expense is based on reducing the requested amount of expenses for the 2010 test year to the 2009 budgeted level. While his testimony addresses the vegetation management, his adjustment encompasses the entire Account 593. He does not address the specifics for reducing any other items in the account beyond vegetation management.

On the other hand, OPC witness Schultz calculated his adjustment based on the number of miles to be trimmed. We believe this approach is more reasonable, because it targets the item the witnesses discuss, that is, the vegetation management.

OPC witness Schultz testified that the increase in tree trimming expense suggests that the Company did not perform the necessary trimming in the prior years and is trying to make up for it in the test year. Witness Schultz asserted that the amount allowed in rates should be based on the annual trimming requirement, not on deferred costs. We agree. We believe the large increase in the number of miles to be trimmed is indicative of deferred maintenance.

OPC witness Schultz recommended an adjustment of $8,924,197 jurisdictional for distribution vegetation management. His calculation is based on the trimming of the 18,341 primary conductor miles over a five-year period using the Company's $5,538 cost per mile. He added $5 million for trimming of the remaining 7,297 miles that consist of secondary conductors.

We note that 3,668 primary conductor miles would be trimmed each year over the five years, along with 1,459 miles of secondary conductors.

We do not believe ratepayers should pay for deferred maintenance. The adjustment recommended by OPC witness Schultz is based on a reasonable estimate of the vegetation management cost. Further, it allows for an increase over the 2009 budged amount for Account 593, even after the adjustment is made. Accordingly, we find that distribution vegetation management O&M expense shall be reduced by $8,924,197 jurisdictional for the 2010 test year.

V. Amortization Period for Rate Case Expense

Rate case expense is shown on MFR Schedule C-10. PEF requested total rate case expense of $2,787,000 with a two-year amortization period, which yields a test-year amortization expense of $1,393,500. PEF submitted updated support for its rate case expense showing projected costs through the end of the hearing.

OPC witness Schultz testified that PEF's rate case expense is excessive. He stated that the expense portion of the request should be reduced by $989,618. He stated that the amount requested does not reflect the contractual terms of the consultants and lawyers. He stated that the costs were overstated by $70,090 for consultants and by $697,500 for attorneys. The total amount of rate case expense witness Schultz recommended was $2,019,410.

Three areas of cost shown in the exhibit are higher than originally projected, while one is lower. The lower expense estimate is for legal costs. The Company initially projected legal costs of $2,000,000. The revised expense of $1,376,258 results in a reduction of $623,742 from the original filing, which is close to OPC's recommended reduction of $697,000. We find that the legal expense of $1,376,258 as projected by PEF shall be allowed.

The higher areas of expense include outside consultants, travel, and printing and administrative costs. The Company submitted a revised estimate for consultants that was $15,707 higher than originally shown in the MFRs. We reviewed the invoices and contracts supporting the costs. There was no support provided for the additional amount for the consultants. The accompanying production of documents did not include any invoices, estimates, or additional support for the increased amount for consultants. OPC witness Schultz testified that consultant costs were overstated by $70,090. His position was unrebutted. This adjustment is a reduction to the original filing amount of $600,000, which would result in a consultant expense of $529,910. We believe the amount proposed by OPC is reasonable, and it shall therefore be allowed.

The explanation PEF provided for travel costs for the hearing is based on hotel costs of $130 per day, food of $50 per day, and 9 cars at $50 per day, for 14 days for 36 people; however, the hearing was completed one day early. Further, we do not believe all witnesses were present at the hearing the full time. PEF's costs were based on all 36 persons remaining at the hearing for a full 14 days. By dividing the travel expense associated with the hearing of $107,820 by 14 days, one day less of hearing would result in a reduction of $7,701. Further, we believe hotel expenses of $130 per day and $50 per day for meals are excessive for Tallahassee. The

Company did not submit any reservation confirmations, hotel names, or other documentation in support of its request. We do not believe the Company has justified the additional travel expense. The amount originally requested of $110,000 shall be allowed.

The only explanation given for the printing costs is that it was for printing of rate inserts and cost of service. No other explanation has been provided for the additional cost. We reviewed the invoices and other supporting documentation provided by the Company. We believe there is sufficient support for the cost of printing that the Company requested. Therefore, the entire printing cost of $137,687 is allowed.

Table 9: Rate Case Expense

	Original Filing MFR C-10	OPC Recommended Adjustment	Company Updated Filing	Difference from original filing	Commission Approved Amount
Legal Services	$2,000,000	($697,500)	$1,376,258	($623,742)	$1,376,258
Outside Consultants	$600,000	($70,090)	$615,707	$15,707	$529,910
Travel	$110,000	0	$121,426	$11,426	$110,000
Printing & Administrative	$77,000	0	$137,687	$60,687	$137,687
Total expense	$2,787,000	($767,590)	$2,251,077	$535,922	$2,153,855

PEF witness Toomey and OPC witness Schultz disagreed over the proper amortization period for rate case expense. PEF asked for two years, while OPC recommended a five-year amortization. PEF argued that it is entering a period of rapid capital investment that increases the likelihood of more frequent rate cases. PEF also argued that the expected rapid capital expansion is similar to the early 1990s, when it was common for us to approve two-year amortization periods.[51] The only support offered for the two-year amortization is a case that occurred in 1982, as pointed out by PEF and FIPUG.

OPC witness Schultz testified that the two-year amortization period is not consistent with ratemaking principles. He noted that PEF cited a 1982 case as the basis for the amortization period, but ignored rulings in more recent years, as well as the length of time that typically extends between a company's rate cases. Witness Schultz recommended a five year amortization period to reflect the timing of rate case filings in recent years and to help reduce the immediate impact on ratepayers. OPC stated in its brief that rate case expense should be reduced by $989,618 and the amount included in rate base should be reduced by at least $2,787,000.

[51] See, e.g., Order No. 11307, issued November 10, 1982, in Docket No. 820007-EU, In re: Petition of Tampa Electric Company for an increase in its rates and charges and approval of a fair and reasonable rate of return.

In recent years, the four-year amortization has been reflected in a number of cases, including the TECO and Peoples Gas cases.[52] In both cases, OPC argued for a five-year amortization period, while the companies argued for lesser amortization periods. We do not believe either party gave sufficient support to vary from the four-year amortization period that has been used recently by this Commission. Further, the four-year amortization is supported by FIPUG. We do not believe PEF has provided sufficient evidence to vary from established practice. Given the differences among the parties, the four-year period falls between the high and low amortization periods and is consistent with our recent practice. We believe a four-year amortization is appropriate.

Based on the above, we find that rate case expense shall be set at $2,153,855 with a four-year amortization period. The annual amortization amount shall be $538,464 ($2,153,855/4). The Company's total requested rate case expense amount shall be reduced by $633,145 ($2,787,000 - $2,153,855), and the annual amortization shall be reduced by $855,036 ($1,393,500 - $538,464).

W. Bad Debt Expense

We hereby find that no adjustment shall be made to bad debt expense for the 2010 projected test year.

X. Test Year Depreciation Expense

We calculated composite depreciation rates for each of the six functional areas of plant. The composite rates are as follows:

Steam Production	2.3 percent
Nuclear Production	2.3 percent
Other Production	3.1 percent
Transmission	2.2 percent
Distribution	2.9 percent
General	4.9 percent

Using these factors and the monthly plant balances shown on MFR schedule B-8, we calculated the depreciation expense for the 2010 projected test year using the composite rates. In addition, the jurisdictional amount of the depreciation surplus of $23,279,396 is to be amortized over 4 years for $5,819,849 per year. ($23,279,396/4 = $5,819,849) Accordingly, we find that the 2010 projected test year depreciation expense shall be reduced by $112,753,601 jurisdictional, to reflect the approved depreciation rates, capital recovery schedules, and amortization schedules resulting from PEF's depreciation study, plus the amortization of a portion of the reserve surplus of $5,819,849 per year for four years.

[52] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 67; Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 29.

Y. Depreciation and Fossil Dismantlement Expense

Based on our adjustments discussed herein, we find that the appropriate retail Depreciation and Amortization Expense for the 2010 projected test year is $239,311,191, as reflected on Schedule 3 attached hereto. We further find that the appropriate System Annual Accrual amount for fossil dismantlement is $3,845,221, and the retail annual accrual amount is $3,113,889, as previously discussed.

Z. Nuclear Decommissioning Expense

We find that the appropriate amount of nuclear decommissioning expense for the 2010 projected test year is $0.

AA. End of Life Material and Supplies Inventories

We find that no adjustments shall be made to the amortization of End of Life Material and Supplies inventories.

BB. Costs Associated with the Last Core of Nuclear Fuel

We find that no adjustments shall be made to the amortization of the costs associated with the last core of nuclear fuel.

CC. Taxes Other than Income

Based on our decisions herein, we find that taxes other than income taxes for the 2010 projected test year shall be increased by $86,813 for an adjusted total of $129,673,813, as reflected in Schedule 3, attached hereto.

DD. Parent Debt Adjustment

Rule 25-14.004, F.A.C., states that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." Further, Rule 25-14.004(3), F.A.C., states that "it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure." Rule 25-14.004(4), F.A.C., provides that:

> The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall be multiplied by the statutory tax rate applicable to the consolidated entity. This result shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

We believe that Rule 25-14.004, F.A.C., is based on the premise that debt at the parent level supports a portion of the parent's equity investment in the subsidiary. Since the interest expense on such debt is deductible by the parent for income tax purposes, the income tax expense of the regulated subsidiary should also be reduced by the same tax effect. The reduction in income tax expense enjoyed by the parent should be shared with the regulated subsidiary and the ratepayers. As of June 30, 2009, Progress Energy had $3.35 billion of long-term debt outstanding. The equity ratio for Progress Energy was 42.4 percent as of December 31, 2008.

We believe that PEF has not demonstrated that the investment made by Progress Energy in PEF can be attributed to any source other than the general funds of the parent. We believe the record shows that no equity contributions were made to PEF until 2009. The projected equity infusion from Progress Energy to PEF in 2009 is $640 million. However, we believe that PEF has not met its burden of proof to demonstrate its claim that all contributions made and expected to be made by Progress Energy to PEF in 2009 and 2010 will be from funds generated from common equity issuances at Progress Energy.

In a prior rate case involving Indiantown Company, Inc., we ordered that a parent debt adjustment was required:

> Based on our analysis, the rule requires that a parent debt adjustment be made in this proceeding. Further the rule does not allow for specific identification of debt from the parent to the subsidiary utility. Since the utility is included in the consolidated income tax returns of the parent, we believe that it would be very difficult to prove specific identification to only the utility. Rule 25-14.004(3), Florida Administrative Code, states that it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.[53]

In Docket No. 080317-EI, we also applied the parent debt adjustment in the TECO rate case and concluded that TECO did not effectively rebut the presumption that a parent debt adjustment should be applied pursuant to Rule 25-14.004, F.A.C.[54]

We acknowledge that none of the intervening parties proffered testimony regarding the parent-debt adjustment. However, we believe that the lack of testimony by the intervening parties does not constitute support for PEF's argument to not make a parent-debt adjustment pursuant to our rules. Evidence in the record that Progress Energy issues debt at the parent level was not rebutted. The fact that Progress Energy files a consolidated tax return was also uncontroverted. We believe that PEF has not met its burden to show that the debt of the parent is not invested in the equity of its subsidiary and that PEF has not effectively rebutted the presumption that a parent debt adjustment should be applied pursuant to Rule 25-14.004, F.A.C.

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[53] See Order No. PSC-00-2054-PAA-WS, issued October 27, 2000, in Docket No. 990939-WS, In re: Application for rate increase in Martin County by Indiantown Company, Inc.

[54] See Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 75-79.

We believe that the parent debt adjustment should be applied in this case, and the elements of the computation should be based on the projected test year capital structures of Progress Energy and PEF. In PEF's response to Staff's Nineteenth Set of Interrogatories, No. 212, PEF provided the following financial information necessary to make a parent debt adjustment for the 2010 test year in accordance with Rule 25-14.004, F.A.C.

Capital Structure of the Parent

Long-Term Debt	$3,717,224,000	39.64%
Short-Term Debt	$315,994,000	3.37%
Common Equity	$5,345,190,000	56.99%
Total Capitalization	$9,378,408,000	100.00%

Cost of Debt of the Parent

Weighted average cost of long-term debt for Progress Energy	7.515%
Cost of short-term debt for Progress Energy	4.50%
Weighted average cost of long-term and short-term debt	7.288%

Applicable Consolidated Tax Rate 38.575%

Equity Dollars of the Subsidiary

Equity dollars of PEF, excluding retained earnings: $1,971,076,000

Our calculation of the system income tax reduction is as follows:

Debt Ratio of parent	.4301
Debt Cost Rate of parent	x .07288
	= .0313456
Consolidated Tax Rate	x .385750
	= .0120915
Subsidiary Equity	x $1,971,076,000
Parent Debt Adjustment	= $23,833,265

In MFR Schedule C-4, page 16, PEF calculated a jurisdictional separation factor for income taxes of 0.60787. Applying this factor to the parent debt adjustment calculated above results in a jurisdictional adjustment of $14,487,526 ($23,833,265 x 0.60787).

We find that PEF has not effectively rebutted the presumption that a parent debt adjustment should be applied pursuant to Rule 25-14.004, F.A.C. Further, the appropriate subsidiary equity amount to be used in the calculation is the projected test year equity of $1,971,076,000. Accordingly, the appropriate jurisdictional adjustment is a reduction of income tax expense in the amount of $14,487,526 ($23,833,265 system).

EE. Income Tax Expense

PEF proposed an initial Income Tax expense of $44,490,000 (MFR Schedule C-2 p5), but agrees that reductions to expenses made by us will increase the Income Tax expense based on the statutory income tax rate of 38.575 percent.

The Income Tax expense is a result of other adjustments made by us. Based on our decisions contained herein, the requested total income tax expense of $42,943,000 shall be increased by $114,579,811 resulting in an adjusted total Income Tax expense of $157,522,811.

Amount Requested	$42,943,000
Adjustments:	114,579,811
Total Income Tax Expense	$157,522,811

FF. Operating Expenses

We find that the appropriate level of Operating Expenses for the 2010 projected test year is $1,153,399,488, as reflected in Schedule 3, attached hereto.

GG. Net Operating Income

We find that the appropriate net operating income for the 2010 projected test year is $496,619,512, as reflected in Schedule 3, attached hereto.

HH. Affiliated Transactions

Progress Energy, the parent company of PEF, has divested the great majority of its non-regulated utility businesses since 2005. Approximately 0.1 percent of PEI's revenues came from non-regulated businesses in 2008.

OPC witness Dismukes testified that cost allocations to affiliates should be frequently reviewed to determine that the Company's regulated operations are not subsidizing the non-regulated operations. She stated that the arms-length bargaining of a normal competitive environment is not present in transactions with affiliates. She asserted that there is an incentive to misallocate or shift costs to regulated companies so that the non-regulated companies can reap the benefits. The witness stated that our rules set forth the criteria to be followed by electric utilities for affiliate transactions.[55] She testified that it is the utility's burden to prove that its costs are reasonable.

OPC witness Dismukes stated that the Company offers numerous products and services that are not regulated or tariffed by this Commission. She explained that the revenues and costs for these products and services are recorded below-the-line for ratemaking purposes. She advised that there is an incentive to shift costs to the regulated operations, thus yielding higher

[55] Rule 25-6.1351, F.A.C.

profits for PEF and its parent company PEI. She stated that we should ensure that the regulated operations of PEF do not subsidize the non-regulated operations.

OPC witness Dismukes further testified that we do not have rules governing the costs charged between regulated and non-regulated operations of electric utilities. She stated that we can utilize the same principles embodied in our affiliate transactions rules as guidelines for examining the relationship between the Company's regulated and non-regulated operations.

PEF addressed OPC witness Dismukes' recommendation that we move all the revenues, expenses, and investment associated with these non-regulated operations above the line for ratemaking purposes. PEF argued that we must reject this recommendation, because we do not have legal authority to regulate non-regulated operations. PEF stated that a search of our orders revealed no authority for witness Dismukes' recommendation. PEF argued governance costs for non-regulated operations are properly assigned to the non-regulated operations as explained by PEF witness Toomey and in PEF's responses to OPC's Twelfth Set of Interrogatories, No. 402 and OPC's Tenth Request for Production of Documents, No. 250.

We agree with PEF that non-regulated activities and their associated expense are recorded "below-the-line" and, as a result, do not impact the Company's revenue requirement request. As noted by the Company, Rule 25-6.1351(2)(g), F.A.C., defines non-regulated operations as "services or products that are not subject to price regulation by the Commission or not included for ratemaking purposes and not reported in surveillance."

The basis for OPC witness Dismukes' belief that costs are not properly allocated is that the profit percentages have been large for non-regulated services. However, no evidence was provided that supports the allegation that specific costs were misallocated. No examples of a specific cost that was misallocated was provided. OPC witness Dismukes acknowledged that some governance costs for non-regulated operations are assigned to the non-regulated operations.

We note that the non-regulated transactions are audited by our staff auditors. One of the stated objectives on the PEF audit was to review intercompany charges to and from affiliated companies and non-regulated operations to determine if an appropriate amount of costs were allocated pursuant to Rule 25-6.1351, F.A.C. Based on the evidence, we believe that the Company is following the correct methodology for allocation of its non-regulated costs. Accordingly, we find that PEF has appropriately accounted for affiliated transactions; thus, no adjustment shall be made.

X. REVENUE REQUIREMENTS

A. Projected Test Year Expansion Factor and Net Operating Income Multiplier

We hereby find that the appropriate projected test year revenue expansion factor is 61.207% and the appropriate net operating income multiplier is 1.63381.

B. Annual Operating Revenue Increase

Based on our decision herein, the appropriate annual operating revenue increase for the 2010 projected test year is $0, as reflected on Schedule 5 attached hereto.

XI. COST OF SERVICE AND RATE DESIGN

A. Revenues at Current Rates

PEF basic position is that the revenues submitted in their original March 2009 filing were appropriately calculated for the 2010 projected test year. The AG and FRF do not take a position with respect to the revenues filed in PEF's original filing, but object to using the revised sales forecasts filed by the Company on August 31, 2009.

We believe PEF did not correctly calculate revenues at current rates for the projected test year. The initial revenue calculations submitted in the MFR Schedule E-13c excluded revenues received from the Bartow Repowering Project (BRP), which went into base rates on July 1, 2009. In response to our staff's Twelfth Set of Interrogatories, No. 136, the Company provided revised calculations to include revenues received from the BRP. The revision of revenue calculations increased PEF projected revenues from $1,448,466,000 to $1,580,567,000, a difference of $132,101,000. In witness Slusser's deposition, he agreed that the BRP revenues should be included in the revenue calculations at current rates for the projected test year.

We hereby find that revenues at current rates for the projected test year shall be increased from $1,448,466,000 to $1,580,567,000, or by $132,101,000, to account for the Bartow Repowering Project base rate increase approved by us in Order No. PSC-09-0415-PAA-EI, issued June 12, 2009, in Docket No. 090144-EI.

B. Separation of Costs and Revenues

Upon the withdrawal of PEF's revised sales forecast, none of the parties challenged PEF's 2010 jurisdictional separation cost study methodology. We reviewed the jurisdictional separation methodology incorporated in the jurisdictional cost study that was filed in Section E of PEF's MFRs. We believe that the methodology is appropriate and that the methodology was consistently applied to forecasted 2010 costs and revenues. Accordingly, we find that PEF's proposed separation of costs and revenues between the wholesale and retail jurisdictions is appropriate.

C. Cost of Service and Allocation Increase

Based on our decision to deny any increase in revenue requirement and the expressed desire to keep rates at existing levels, we deny PEF's proposed change to the cost of service methodology. Any change in the cost of service methodology has the potential to change rates by reallocating costs across rate classes. This decision also leads us to deny the proposals to change the cost recovery factors, and deny any increase in service charges, the Temporary Service charge, and Premium Distribution Service charges. Since there was no change in revenue requirement, the decision on the allocation of an increase is moot. Similarly, issues setting customer charges, Standby Service charges, energy charges, demand charges and lighting charges are moot since neither the total revenue requirement nor the cost of service methodology changed.

D. Methodology for Treatment of Unbilled Revenue

We find that PEF's proposed methodology for treatment of unbilled revenue due to any rate change is appropriate.

E. Charge for Investigation of Unauthorized Use

We find that PEF's proposed charge for Investigation of Unauthorized Use is appropriate.

F. Treatment of Interruptible Customers

Consistent with our decision to deny any change in rates, we deny the proposal to eliminate the IS-1 and IST-1 rate classes which renders the grandfathering of IS-1 conditions moot.

We also find that the IS credit should remain at its current levels. PEF argued that the level of the interruptible and curtailable credits and the associated payment structure are not base rate issues and are not appropriate for resolution in this docket. PEF's current IS-1 and IS-2 credit levels were set by Order No. PSC-07-0900-PAA-EI.[56] PEF further asserts that the value of the Company's ability to interrupt or curtail the demand is reflected in a billing credit, not in base rates. PEF also stated that we treat such credits as a demand side management program. This means that the level of the credit must be cost-justified in the same manner as the cost of any other demand-side management (DSM) program. It also means that the credit payments are accounted for as DSM costs, and are recovered from all customers through the conservation cost recovery clause. The DSM goals docket or the conservation clause docket is thus the proper forum to address the cost-effective level of the credit and its payment structure.

FIPUG contended that a value of $10.49 per kW-Month is the appropriate value for interruptible credits. FIPUG's $10.49 per kW-Month value is derived from a document provided by PEF to FIPUG in response to a production of documents request. FIPUG did not provide an independent calculation or analysis supporting its recommended value.

PEF witness Slusser testified that the cost-effectiveness study relied upon to develop the $10.49 per kW-Month value was prepared as long as two years ago and further claimed that things would change if the study was redone. Witness Slusser additionally disagreed with certain terminology regarding the document which contained the $10.49 per kW-Month value. No PEF witness was identified that could speak specifically to any calculations or assumptions

[56] Issued November 7, 2007, in Docket No. 070290-EI, In re: Petition to increase base rates to recover full revenue requirements of Hines Unit 2 and Unit 4 power plants pursuant to Order PSC-05-0945-S-EI, by Progress Energy Florida, Inc.

used in the development of the $10.49 per kW-Month value. Although PEF questioned the $10.49 per kW-Month value, it did not offer an updated cost-effectiveness analysis regarding a more appropriate level of the interruptible credit.

Based on the above, we find that the interruptible credit shall be $3.62/kW for IS-1 customers and $3.31/kW for IS-2 customers.

FIPUG also challenged the load factor adjustment to the IS-2 credit. We approved the load factor adjusted credit for the IS-2 rate in 1996, when we approved the closure of the IS-1 rates to new customers and the new IS-2 rates.[57] Thus, the load factor adjusted credit has been in effect for IS-2 customers since 1996. The load factor adjusted credit was also an issue in the TECO rate case. TECO's General Service Load Management Rider (GSLM) tariff provides for a load factor adjusted credit, similar to PEF's IS-2 rate.

Witness Pollock objected to a load factor adjustment of the credit, testifying that load factor is not a reasonable proxy for the amount of capacity that a customer curtails, and because curtailments can occur at any time, not just during the hour that PEF's monthly coincident peak occurs. Witness Pollock further testified that since PEF proposed to move the IS-1 customer to the IS-2 rate, the combined IS-1/IS-2 class is projected to have an average billing load factor of about 61 percent. This would result in an average load-factor adjusted credit of $2.02.[58] Thus, witness Pollock testified that the Company's proposal to transfer the IS-1 customers to the IS-2 rate, would result in a 44 percent reduction in the interruptible credit currently paid to IS-1 customers.

During the hearing upon cross examination by FIPUG, witness Slusser testified that when the IS-2 rate was developed, much study went into the method of applying the credit and the belief was that by applying it to the load factor adjusted demand was a better measurement of the amount of curtailable or interruptible load that was available.

Order No. PSC-96-0842-FOF-EI, which approved the IS-2 rates, states:

> This adjustment of the amount of the credit is justified because load research data indicates that there is a positive relationship between the customer's billing load factor and his coincidence factor. Coincidence factor is a measure of the relationship between a customer's maximum billing demand and his demand at the time of the system peak. Customers with high coincidence factors are more likely to be on the system at the time of peak demand and thus are more likely to provide significant load reductions to the system when interruptions are required.
>
> While the coincidence factor cannot be measured directly, billing load factor, which measures the relationship between the customer's maximum monthly billing demand and his kilowatt hour consumption, has been shown to track coincidence factor.

[57] Order No. PSC-96-0842-FOF-EI, issued July 1, 1996, in Docket No. 950645-EI, In re: Determination of cost-effective level of demand-side management credit for Interruptible and Curtailable rate classes of Florida Power Corporation.

[58] $3.62 x 44 percent = $2.02

Billing load factor is readily available from billing records and is a suitable proxy for coincidence in adjusting the credits.

Witness Slusser testified that customers are getting the $3.13 per kW credit for what PEF is estimating as the customer's coincident demand, i.e., demand during or coincident with the system peak. The coincident demand is being estimated by applying the load factor to billing demand. Witness Slusser further testified that the IS-1 customers were grandfathered to a generous credit and have had a long transition period. While FIPUG is correct that interruptions may occur at any time, system capacity shortages are most likely to occur during peak usage periods. Witness Pollock provided no data to support his contention that the number of non-peak interruptions were significant enough to change the methodology.

While objecting to the method used by PEF, witness Pollock recommended two alternatives as to how to determine the amount of interruptible demand subject to the credit. This implies that he believes some type of load factor adjustment is appropriate. First, witness Pollock stated that the interruptible demand subject to the credit should be based on customer's normal operating demand for a defined base line period using actual data from a prior critical period. In the alternative, witness Pollock recommended directly measuring the amount of interruptible demand in real-time for each customer. Witness Pollock stated that this process is similar to determining the generation and transmission capacity charges in the standby rate and should not be burdensome to require the same process in determining the interruptible credit.

We believe that there is not enough evidence in the record to determine whether witness Pollock's recommended alternatives to determining the amount of interruptible demand are reasonable. To determine the appropriate credit amount, the utility would need to know what the customer's demand was coincident with the system peak during an interruption event. PEF's current load factor adjusted credit provides an estimate of what the customer's load would have been during the monthly system peak.

Based on the foregoing, we agree with PEF that there is no basis in this docket to change the application of the IS-2 credit. However, we believe that witness Pollock's two recommended alternatives to determine the amount of interruptible demand subject to the credit merit review by PEF. We direct PEF to review witness Pollock's alternatives, and provide an analysis to this Commission for review when it submits its demand-side management programs for approval following the DSM goal setting proceeding.

G. Closure of RST-1 Rate to New Customers

We find that PEF's proposal to close the RST-1 rate to new customers is hereby approved.

H. Monthly Fixed Charge

We hereby find that the methodology used by PEF to calculate the monthly fixed charge carrying rates is appropriate. To the extent any of the inputs used by PEF in the calculation are modified by this Commission, PEF should recalculate the monthly fixed charge carrying rates using the approved inputs.

I. Delivery Voltage Credits

We hereby find that PEF's delivery voltage credits are appropriate.

J. Power Factor Charges and Credits

We find that PEF's power factor charge and credit of $0.25 kilovolt-ampere reactive (kVAR) is appropriate.

K. Time-of-Use Metering Costs

We hereby find that PEF's $90 lump sum payment contained in the RST-1 rate for time-of-use metering costs is appropriate.

L. Time-of-Use Rates

AFFIRM represents a coalition of quick serve restaurants that have substantially similar usage patterns, such as Waffle House, Wendy's, Arby's and YUM! Brands. PCS is a large industrial customer. In its brief, AFFIRM stated that it has two main reasons for intervening in this case. The primary objective is to seek a more appropriately structured time-of-use rate for the AFFIRM Members that are served under the General Service Demand family of rates. Witness Klepper stated that usage patterns of AFFIRM members are materially different from the majority of commercial customers because their monthly peaks typically occur during what most utilities deem to be either off-peak or shoulder hours. Witness Klepper further noted that the only other rate schedule available to AFFIRM's customer base is the General Service Demand Time-of-use (GSD-T) rate schedule. However, witness Klepper believed the current GSD-T rate is highly ineffective because of the higher customer cost, and because the ratio of on-peak to off-peak usage for AFFIRM's clients is greater than the system average, resulting in more usage billed at on-peak rates. He stated that commercial customers who wish to become more efficient are denied the opportunity to make efficiency improvement, due to the limited on- and off-peak pricing periods in current rates. It is AFFIRM's position that a new commercial time-of-use rate should be developed which recognizes the variability in GSD customer usage patterns to better match costs and revenues in each time period. AFFIRM's primary objection to the current GSD-T rate appears to be that it contains two broad pricing periods which results in shoulder peak usage being billed at on-peak rates when the cost of providing the energy may be less than a more narrowly defined peak period. AFFIRM asked us to require PEF to design a multi-period time-of-use rate.

PEF's current time-of-use methodology was established in its 1991 rate case.[59] PEF has not proposed any change in the method used to calculate time-of-use rates in this proceeding.

[59] Order No. PSC-92-1197-FOF-EI, issued October 22, 1002, in Docket No. 910890-EI, In re: Petition for a rate increase by Florida Power Corporation.

The Cost of Service And Rate Design Stipulation in that 1991 case set forth the methodology to be used.

> The rate design for all Time-Of-Use (TOU) rates will set the off-peak energy rate at the average system energy component from the cost of service study (approximately 0.580 cents per KWH). The on-peak charge will then be the result of a break even calculation with the standard rate, based on the rate class's or combined rate classes' on-peak and off-peak energy consumption. (The combined classes will be the RS-1 and GS-1 and GSD-1 and GSLD-1 classes; the CS-1 class and the IS-1 class will be individual classes.) For Demand TOU rates, a demand charge equivalent to 1/2 (sic) of the unit cost for Distribution Plant will be applicable to the customer's maximum measured demand. The on-peak demand charge shall include [in addition to production costs] the on-peak unit cost for Transmission Plant and 1/2 of the on-peak unit cost for Distribution Plant.[60]

Witness Slusser discussed PEF's TOU methodology in his deposition. He noted that if the customer can shift usage so that his maximum usage occurs outside of peak hours, the applicable demand charge is less than the otherwise applicable demand charge for flat rate customers and the customer benefits from the time-of-use rate. If his maximum demand occurs during peak periods, he will pay the same as if he were on a flat rate.

The energy charge likewise reflects on and off-peak costs. Non-fuel base rate energy charges are designed assuming using the on- and off-peak usage ratios for the whole class. If a customer uses less energy on-peak than the class average, he will see a reduction in his bill because the off-peak energy charge is lower than the flat rate energy charge. Witness Slusser also pointed out the fuel cost differentiation for on- and off-peak usage. Like the non-fuel energy charge, the fuel charges are set, using the system's on- and off-peak energy ratios. If a customer's usage shows a higher percentage off-peak than the system average, he will realize a lower fuel cost compared to a flat rate.

Witness Slusser took issue with several points raised by AFFIRM. First, he pointed out that PEF was able to identify 151 AFFIRM customer accounts and of those a predominance of these customers take service under the GSD-T rate schedule. Exhibit 253 indicated that, as a whole, GSD commercial customers who take service on the GSD-T rate realize an eleven percent lower cents/kWh cost for electricity that those who take service on the GSD rate. Witness Slusser also noted that this same exhibit shows that the identified AFFIRM customers have a slightly higher on-peak load factor as the total GSD class. As discussed above, the GSD-T base rate is designed using the class on- and off-peak ratios. Also, the on- and off-peak fuel rates are design using the system on-peak percentage which witness Slusser stated is thirty-two percent, not forty-five percent as alleged by the AFFIRM witness. If the average AFFIRM customer has an on-peak usage factor of twenty-nine percent, he will benefit from the time-of-use rate.

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[60] Id., Cost of Service And Rate Design Stipulation, p. 5-6

Witness Slusser noted that PEF does not have time recording meters on any AFFIRM customers to record hourly data. However, PEF does have a similar fast food customer included in the Cost of Service Load Research study.[61] The study results for this customer appears to show long periods of on-peak usage under the currently approved definition of peak and off-peak periods. Even so, the on-peak percentage of this customer is only twenty-eight percent which indicates that he would benefit from the GSD-T rate. However, witness Slusser also stated that PEF is already studying ways to better recognize the incentives to move consumption from peak periods to off-peak periods and to establish what are critical pricing periods are.

PEF's current GSD-T rate schedule was approved by this Commission in 1992. This is the first proceeding in which AFFIRM has raised their allegations of unfairness. They were not a party to either the 1991, 2001, or the 2005 rate cases. AFFIRM asked us to direct PEF to develop a new commercial time-of-use rate that would be more effective by providing periodic price signals. While witness Slusser appears to recognize that a new rate may be appropriate at some point, AFFIRM presented no specific rate design to be considered in this proceeding defining alternative rating periods, and provided no specific usage data to support any alternative rate design. In addition, witness Slusser demonstrated that, contrary to witness Klepper's testimony, AFFIRM customers currently take service on the GSD-T rate and realize a lower cents/kWh, diluting the argument that something needs to be done immediately.

The current on- and off-peak rating periods were established by this Commission when it adopted the Public Utility Regulatory Policy Act (PURPA) recommendations on time-of-use rates. The periods have remained essentially unchanged since the early 1980s. The rating periods were set at that time, based on utility load data.[62] We disagree with AFFIRM's contention in its brief that the current time-of-use rate design does not comply with federal requirements. The current rate design does recognize that usage which occurs outside the designated peak periods can be served at a lower cost. AFFIRM seems to simply argue that a more finely delineated rate would do a better job of that.

Witness Slusser indicated that PEF is already considering alternatives to the current pricing incentives to encourage customers to shift usage to off peak periods. A utility may propose a new optional rate structure at any time, and in fact, Gulf Power Company (Gulf) and Tampa Electric Company (TECO) have received approval for multi-period time-of-use pricing for residential customers.[63] TECO has also received approval for a pilot program offering multi-period time-of-use pricing for General Service customers (non-demand metered commercial

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[61] Rule 25-6.0437, F.A.C., requires IOUs to install time recording meters on a statistically valid sample of all customer classes to collect usage information on an hourly basis to determine the factors used to allocated costs to rate classes. These studies are performed every three years at a minimum.
[62] Order No. 9661, issued November 26, 1980, in Docket No. 780793-EU, In re: Show Cause order to electric utilities concerning peak load pricing for general service customers, and Docket No. 790859-EU, In re: General investigation into electric rate structures to see whether they tend to promote the conservation of energy.
[63] Order No. issued June 9, 1995, in Docket No. 941172-EG , In re: Approval of Demand-Side Management Plan of Gulf Power Company; and Order No. PSC-05-0181-PAA-EG, issued February 16, 2005, in Docket No. 040033-EI, In re: Petition for approval of numeric conservation goals by Tampa Electric Company.

customers).[64] However, in the TECO and Gulf cases, the utilities came forward with the proposal, and justified the programs based on load research information. Hourly usage data is necessary to determine if different or multiple rating periods were appropriate, and if so, what those rating periods should be, based on system cost information.

As a practical matter, witness Slusser stated that current GSD metering does not have the capability to record hourly usage for AFFIRM's customer base. The installation of meters capable of recording and transmitting hourly data to the utility could approach $30,000 per location. The costs for installing such advanced metering has not been considered in this case. Relevant load information is not available in this docket. It is inappropriate to require PEF to propose a new rate without knowing if any such program is cost effective to the general body of ratepayers.

Accordingly, we find that the time-of-use rate design proposed by PEF in this docket is appropriate and is hereby approved. AFFIRM had identified what it perceives as problems, but did not propose any specific changes which could be considered in this proceeding. We believe there is insufficient evidence in this record to approve any changes to the method proposed by PEF at this time. PEF has provided evidence that AFFIRM members currently benefit from the proposed rate design, although perhaps not to the degree those customers would like. PEF has stated that it is already investigating potential options to modify to its time-of-use rates. There are clearly costs associated with measuring usage in more discrete intervals necessary to properly design a new rate, and those costs have not been identified or considered in this case. Neither has the impact on other customers, other than AFFIRM's members, or any impact on revenues, been discussed or determined in this case. Any new rate design must consider the overall impact, not just the impact on those customers who stand to benefit directly from any change. We further find that PEF continue to work on an option which offers more narrowly defined rating periods and provide our staff by July 1, 2010 a proposed tariff for a multi-period commercial time-of-use rate, if available, or at a minimum, a report on their progress in defining such a new tariff. We believe that is a reasonable time frame to conduct the necessary load and cost analysis to at least identify some possible cost effective options. When PEF files a proposed tariff, AFFIRM will have adequate opportunities to participate in any future changes to time-of-use rate design.

M. Leave Service Active Provision

PEF was the only party to address this issue in witness Slusser's direct testimony. The Leave Service Active Agreement (LSA) is an option offered to landlords to maintain service to rental units between tenants, to avoid reconnection charges. If a landlord signs an LSA, he agrees to be responsible for electric usage at the designated rental units between termination of service by one tenant and initiation of service by another. This allows the landlord to continue electric service to clean and maintain the premises between tenants without the need to pay to establish service in his name, then discontinue service and require a new tenant to pay to establish service in their name. It is a more efficient process for both the utility and the landlord

[64] Order No. PSC-09-0501-TRF-EG, issued July 15, 2009, in Docket No. 090228-EG, In re: Petition for approval of a pilot small general service price responsive load management program, by Tampa Electric Company.

to simply transfer the name on the service. This provision has been in PEF's tariffs since the early 1980's. Although the language does not appear in its tariffs, PEF currently limits the availability of the LSA option to landlords with ten or more units. It has proposed to add language specifying the ten unit minimum to Tariff Sheet 6.110, along with language which requires rental properties to be multi-family and on contiguous property. PEF believes this is appropriate because fewer units or units which are not contiguous may lack adequate supervision to ensure that tenants do not simply discontinue service with the utility and remain in the rental unit.

Witness Slusser stated that PEF is adding the language limiting the LSA to landlords with ten or more units for two reasons. First, this is consistent with how the Company is applying the agreement today. Second, he believes that landlords with less than 10 units would not be able to provide close supervision of their properties and may not be aware of when tenants leave. The concept of LSA was initially developed to address an issue raised by an apartment owners association who managed large rental projects. They were able to monitor tenants closely and know when the tenant left and power was transferred to the landlord's name. Witness Slusser believes that today there are more investors buying two and three homes or apartment who aren't in the full time business of managing those rental units. He stated that the Company was uncomfortable dealing with these types of customers when it came to transferring the responsibility of usage at those locations.

PEF provided no specific justification for requiring the presence of an on-site manager, or that the units be contiguous, but we believe these are prudent requirements, to ensure that the LSA agreement is properly administered and enforced. Individual rental units are more difficult to monitor and a landlord may not be aware of the departure of a tenant in a timely manner. This can lead to disputes over when usage was transferred to the landlord. Similarly, we believe the presence of an on-site manager is also an appropriate condition. An absent landlord may not be able to adequately monitor electric usage during vacancies as efficiently as if there was a manager presence at the rental location on a daily basis.

We do not believe that PEF has adequately explained why the number of units should be limited to ten. Witness Slusser agreed that any landlord entering into an LSA agreement would be responsible of all usage for all units covered by that agreement that occurred between tenants. Under the terms of the LSA, once a tenant contacts the utility to discontinue service, the service automatically reverts to the landlord's account. Therefore, the utility is not at risk of non-payment, no matter the number of the rental units subject to the LSA. The utility does not appear to be at any greater risk for bill default for smaller rental groupings than for a unit containing a minimum of ten units. PEF's statement that the customer service personnel did not want to deal with smaller landlords was not supported by any evidence or explanation. Retaining the requirement that the units be contiguous and have an on-site manager appears to be sufficient safeguards without limitation on the number of units eligible for the LSA.

Accordingly, we hereby find that the proposed tariff language be modified to allow an LSA agreement with the requirement that the units be contiguous and that the property have an on-site manager.

N. Effective Date

We hereby find that the revised rates and charges shall apply to meter readings taken on or after February 10, 2010.

XII. OTHER ISSUES

A. Commission's Mandate under Section 366.01, F.S.

We find that in this proceeding, this Commission and our staff thoroughly reviewed and evaluated PEF's petition and MFRs, the testimony and exhibits of all parties, including testimony by PEF customers at a number of service hearings, and all the evidence in the record following a full evidentiary hearing. Our staff then filed its recommendation upon which we based our decision. We then deliberated and voted, as permitted within its statutory discretion pursuant to Sections 366.01 and 366.041(1), F.S., and the confines of the evidentiary record, and approved a change in base rates which was materially different from that proposed by PEF. Based upon the foregoing, we find that we fulfilled our statutory mandate in this proceeding.

B. Interim Rate Increase Refund

By Order No. PSC-09-0413-PCO-EI, issued June 10, 2009 (Interim Rates Order), we authorized the collection of interim rates, subject to refund, pursuant to Section 366.071, F.S. The approved interim revenue requirement was $652,883,238, which represents an increase of $13,078,000 or 0.91 percent. The interim collection period is June 2009 through February 2010.

PEF disagreed with the intervenors' arguments that the interim rates were not lawfully granted and/or barred by the 2005 Stipulation and Settlement of PEF's previous rate case (Stipulation). The legal arguments concerning the Stipulation's impact, if any, on an interim increase were decided by our order granting interim rates. Thus, the intervenors' positions on this issue reflect untimely and improper re-argument pursuant to Rule 25-22.0376, F.A.C. The calculation of any potential refund should be determined by application of Section 366.071(4), F.S. Based upon the evidence in this proceeding, PEF concludes there should be no refund.

OPC argued that the granting of the interim rates by Order No. PSC-09-0413-PCO-EI was based upon an erroneous understanding that the terms of the Stipulation created a 10 percent threshold for purposes of determining interim relief. OPC cited to paragraphs 7 and 14 of the Stipulation in support of its position that PEF did not have an authorized ROE and that the 10 percent threshold referenced in the Stipulation was simply a trigger for seeking a change in base rates when its earnings fell below that threshold. Since the Stipulation did not specifically allow entitlement to interim rates or provide an authorized ROE, PEF was not entitled to interim rates.

Alternatively, OPC argued that PEF made a pro forma adjustment to equity associated with purchase power agreements (PPA). If we disallow this adjustment, then OPC argues that an adjustment must be made to the interim rates revenue requirement calculation in Order No. PSC-09-0413-PCO-EI. OPC's recalculation of the interim revenue requirement, without the pro forma adjustment to equity, shows there was no revenue deficiency for 2009 and, thus, the interim rate increase should be refunded in its entirety.

FIPUG argued that the granting of the Interim Rates Order violated the terms of the Stipulation. FIPUG cites to paragraphs 7 and 14 of the Stipulation in support of its position. FIPUG asserts that PEF did not have an ROE and the 10 percent threshold referenced in the Stipulation was simply a trigger for seeking a change in base rates and not interim rates.

In this case, the arguments raised by the intervenors are substantially the same as the arguments they raised at the May 19, 2009, Agenda Conference, where we voted on whether to approve PEF's interim rate request. Our Interim Rates Order, issued June 19, 2009, addressed the intervenors' arguments when it approved an interim rate increase for PEF. However, the intervenors have failed to provide any new analysis or insight into the Stipulation which would persuade staff to believe that interim rate increase was granted unlawfully. Moreover, the intervenors did not seek reconsideration of the Interim Rates Order.

With regards to OPC's alternative argument, we are similarly not persuaded. Pursuant to paragraph 17 of the Stipulation, PEF was permitted to impute equity for all purposes allowed by the Stipulation for the term of the Stipulation. Since we determined that the Stipulation permitted PEF to request an interim rate increase, then PEF properly calculated its interim revenue deficiency using imputed equity from the PPA agreements. Therefore, we find that the interim rate request was lawfully granted.

According to Section 366.071, F.S., any refund should be calculated to reduce the rate of return of the utility during the pendency of the proceeding to the same level within the range of the newly authorized rate of return. Adjustments made in the rate case test period that do not relate to the period interim rates are in effect should be removed. Rate case expense is an example of an adjustment which is recovered only after final rates are established.

In this proceeding, the test period for establishment of interim rates is the 12-month period ending December 31, 2008. PEF's approved interim rates did not include any provisions for pro forma or projected operating expenses or plant. The interim increase was designed to allow recovery of actual interest costs, and the lower limit of the last authorized range for return on equity.

To establish the proper refund amount, we have calculated a revised interim revenue requirement utilizing calendar year 2009 as a proxy for the interim collection period. Items such as rate case expense and the storm damage accrual were excluded because these items are prospective in nature and did not occur during the interim collection period. Using the principles discussed above, because the $1,522,328,000 revenue requirement granted in Order No. PSC-09-0413-PCO-EI for the December 2008 interim test year is less than the revenue requirement for the interim collection period of $1,714,416,092, we find that no refund is required. Further, upon issuance of the Final Order in this docket, the corporate undertaking shall be released.

C. Required Filings

We find that PEF shall file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records which will be required as a result of our findings in this proceeding.

D. Creation of Regulatory Asset and Deferral of Pension Expense

On March 20, 2009, PEF filed a petition seeking the expedited approval of the deferral of $52.9 million in pension expense (Docket No. 090145-EI). The Company stated that this amount was the difference between actual pension plan income of $21.4 million for the year ended December 31, 2008, and projected pension plan expense of $31.5 million for the year ending December 31, 2009. PEF asserted that the deferral would not involve a change in retail rates or charges. Further, the Company stated that the benefit of the net pension income for 2008 had been recognized and passed on to customers in the interim rate increase calculation in the Company's request for interim relief.[65]

The basis for PEF's request was that unexpected economic conditions had resulted in a significant decline in the fair market value of the pension plan's investments. The Company noted our authorization for the establishment of a regulatory asset as a result of PEF's adoption of SFAS 158[66] in 2007 was required in order to be in compliance with GAAP. PEF asserted that the decrease in the value of plan investments was the result of the severe economic downturn. Because the downturn in the economy was an event beyond its control, the Company contended the deferral requested should be granted. In support of its position, PEF cited to an Order of the Public Service Commission of South Carolina that approved an accounting order for regulatory accounting purposes authorizing South Carolina Electric and Gas Company (SCE&G) to defer certain pension costs as a regulatory asset for recovery in a future period.[67]

On April 3, 2009, OPC, FIPUG, AG, FRF, and PCS (collectively, Intervenors) filed a joint response opposing PEF's petition related to the requested accounting treatment for pension expense. In their consolidated response, the Intervenors objected to approval of PEF's request to defer pension expense to a future period. The Intervenors' objection was based on a number of arguments. The Intervenors stated that pension income for 2008 and the projected pension expense for 2009 fell within the period covered by the 2005 Stipulation. In their opinion, the requested deferral was an attempt to circumvent the express terms of the 2005 Stipulation by shifting results of operations from the stipulation period to a future period. In addition, the Intervenors believed that the requested treatment was a violation of the prohibition against

[65] Order No. PSC-09-0413-PCO-EI, issued June 10, 2009, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc.

[66] SFAS 158 amends SFAS 87, as well as several other Financial Accounting Standards related to pension plans. SFAS 158 requires a company to recognize the funded status of a pension plan (measured as the difference between plan assets at fair value and the benefit obligation) in its statement of financial position. Previously, this information was only required to be disclosed in the footnotes to the company's financial statements.

[67] Order No. 2009-81, issued February 17, 2009, in Docket No. 2009-36-E, In re: Petition of South Carolina Electric and Gas Company (Electric Operations) for Authorization to Defer Certain Charges to the Company's Financial Statements Resulting from the Impact of Recent Economic Developments on Pension Cost.

retroactive ratemaking in that it would be an attempt to recover past expenses in future rates. The Intervenors also stated that the requested deferral would violate the recognition of pension expense specified in SFAS 87,[68] in that pension expense would not be recognized over the approximate service period of the employees covered by the plan. Finally, the Intervenors noted that the economic downturn impacted pension plans across a broad spectrum, including plans of both regulated and nonregulated companies, and as such did not represent an exogenous event unique to PEF.

On April 15, 2009, PEF filed its response to the Intervenors' consolidated response.[69] PEF disagreed with the assertion that the requested deferral would constitute retroactive ratemaking because the Company maintains that it has the right to seek limited proceeding rate relief under the provisions of the 2005 Stipulation. PEF stated that it was not requesting to defer 2009 pension expense to the 2010 base rate proceeding, but to some undefined future base rate proceeding. The Company also disagreed with the Intervenors' assertion that the requested deferral would not conform with the requirements of SFAS 87. PEF cited to paragraph 210 of SFAS 87 which "contemplates that regulators may alter the timing of the recognition of pension expense but not the determination of the cost of the pension benefit."

On July 6, 2009, we issued PAA Order No. PSC-09-0484-PAA-EI, which granted, in part, PEF's request to create a regulatory asset to defer 2009 pension expense (2009 Pension Regulatory Asset). In that Order, we stated: "[b]ased on our reading of the accounting statements, our understanding of the terms of the Stipulation, and the facts alleged in this case, we find that PEF's request to create a regulatory asset to defer 2009 pension expense is hereby approved subject to the conditions outlined above." The conditions specified that the appropriate amount to defer is the retail portion of the actual 2009 pension expense, then estimated to be $31.5 million. In addition, PEF was ordered to use any pension expense levels below the allowance provided for in rates in the 2010 base rate proceeding in Docket No. 090079-EI to write-down the 2009 Pension Regulatory Asset. In the event such write-downs were insufficient to fully amortize the 2009 Pension Regulatory Asset, the Order stated that PEF could not seek recovery of this item through a base rate case prior to 2015. Until that time, the unamortized balance of the 2009 Pension Regulatory Asset would be included in rate base for purposes of earnings surveillance reporting. Finally, we ordered that PEF would not earn a carrying charge on this regulatory asset.

On July 27, 2009, the Intervenors filed a joint petition protesting Order No. PSC-09-0484-PAA-EI. In particular, the Intervenors identified and protested three issues: a) whether PEF violated the terms of the 2005 Stipulation approved in Order No. PSC-05-0945-S-EI by seeking to create a regulatory asset and to defer pension expenses from a period covered by the 2005 Stipulation to a future period; b) whether the creation of a regulatory asset and deferral of

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[68] SFAS 87 prescribes the accounting treatment of defined pension plans. It requires a company to disclose the components of net pension costs and the projected pension benefit obligation. In applying accrual accounting to pensions, SFAS 87 provides that significant economic and financial changes that affect the pension plan do not have to be recognized immediately.

[69] Our rules do not contemplate a response to a response; however, a response providing additional information was requested at the April 8, 2009, informal meeting, which all parties attended. No party objected to PEF's response.

pension expenses from a period covered by the 2005 Stipulation constitutes retroactive ratemaking; and c) whether PEF will double recover its deferred pension expenses deferred from a period covered by the 2005 Stipulation since revenue sharing is the exclusive mechanism for determining earnings for the 2005 Stipulation's duration. The Intervenors further requested that we set Order No. PSC-09-0484-PAA-EI for hearing on PEF's proposal to create a regulatory asset and defer pension expense.

On August 20, 2009, our staff as well as the parties to Docket No. 090079-EI conducted an issue identification meeting for purposes of determining the issues to be addressed at hearing in the rate case. During the pendency of the issue identification meeting, the parties agreed to consolidate the Intervenors' issues raised in the protest of the PAA Order issued in Docket No. 090145-EI into the hearing scheduled in Docket No. 090079-EI. Accordingly, at the request of the parties the Prehearing Officer consolidated Docket Nos. 090145-EI and 090079-EI for the purpose of an evidentiary hearing.[70]

In Order No. PSC-09-0484-PAA-EI, we acknowledged the concern raised by the Intervenors over what appears to be cost shifting from the stipulation period to some future, undefined period. On its face, it appears that the Company's request is an attempt to track the pension expense in 2009 in isolation. According to PEF's 2008 10K filing with the Securities and Exchange Commission (SEC), the Company reported a total pension benefit of approximately $47 million (system) for the years 2006 through 2008.[71] In viewing the four-year stipulation period in its entirety, even with consideration of the projected pension expense of $34 million (system) in 2009, PEF will still enjoy a net pension benefit over the term of the 2005 Stipulation.

As noted in PEF's petition, we previously approved deferral accounting and creation of a regulatory asset when PEF adopted SFAS 158.[72] In our 2006 Order, we stated that:

> FAS 71 allows regulated companies to defer costs and create regulatory assets, provided that it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. To create a regulatory asset or liability, a regulated company must have the approval of its regulator. This concept of deferral accounting allows companies to defer costs due to events beyond their control and seek recovery through rates at a later time. The alternative would be for the company to seek a rate case each time it experiences an exogenous event.

[70] Order No. PSC-09-0586-PCO-EI, issued August 31, 2009, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., and Docket No. 090145-EI, In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.

[71] Florida Power Corporation d/b/a Progress Energy Florida, Inc., Annual Report for the fiscal year ended December 31, 2008 (Form 10K), at 197 (March 2, 2009).

[72] Order No. PSC-06-1042-PAA-EI, issued December 19, 2006, in Docket No. 060674-EI, In re: Petition for authority to use deferral accounting for creation of a regulatory asset in regulatory liability to record charges or credits that would have otherwise been recorded in equity pursuant to balance sheet treatment required by Statement of Financial Accounting Standards (SFAS) No. 158, by Progress Energy Florida, Inc.

We agreed with PEF that SFAS 158 imposed a specific accounting treatment related to the funded status of pension plans. We also agreed with the Company that SFAS 71 permits the deferral of costs through the creation of a regulatory asset under certain circumstances.

That said, certain aspects of PEF's proposal are distinguishable from the South Carolina Electric & Gas (SCE&G) decision for several reasons. First, the South Carolina order expressly stated that approval of SCE&G's request for deferral was predicated in part on the South Carolina Commission's ability to avoid consideration of a rate case to increase base rates. Since PEF is currently before the Florida Commission with a request for an increase in base rates in Docket No. 090079-EI, PEF's request for deferral of the 2009 pension expense is not directly comparable with the situation in South Carolina. Second, another difference between the two cases arises from the disparate treatment of the pension expense for ratemaking purposes by the respective Commissions. In the South Carolina matter, the revenue requirement approved in 2007 for SCE&G in its most recent rate case expressly recognized an annual pension benefit of approximately $4 million. This treatment has had the effect of reducing SCE&G's operating and maintenance (O&M) expense, thereby reducing customer rates.[73] In contrast, the order approving the 1993 step increase in base rates for PEF included an annual pension expense of approximately $3.8 million.[74] This treatment has had the effect of increasing PEF's O&M expense and thereby increasing customer rates. While the South Carolina decision recognized the sum of the annual amount of pension benefit expressly reflected in base rates with the projected pension expense in that same year (2009), PEF's request asked that the pension benefit from the prior year (2008) be added to the projected pension expense in 2009. These two requests are not the same. The 2005 Stipulation was silent with respect to pension expense.

While we find that we have the discretion to create a regulatory asset to defer pension expense, we question the calculation of the proposed deferral amount. For the reasons discussed above, it would be inappropriate to use the sum of the 2008 pension benefit and the 2009 pension expense to determine the deferral amount. Contrary to the position advanced by PEF, we do not believe the $21.4 million pension benefit from 2008 is embedded in the Company's 2009 revenue requirement. The pension benefit from 2008 has already been booked to income by the Company and is not relevant to the amount of pension expense PEF will incur in 2009. We believe the appropriate amount to defer is the retail portion of the actual 2009 expense which at the time of PEF's petition was estimated to be $31.5 million.

We also acknowledge the Company's claim that it is not seeking a change in rates associated with the 2009 pension expense. While the MFRs filed in Docket No. 090079-EI in support of its rate case reflected an annual pension expense of $27.1 million for the 2010 projected test year, PEF did not include any recognition of the 2009 pension expense in its filing. Moreover, PEF shall use any pension expense levels below the allowance provided for in rates in the 2010 base rate proceeding in Docket No. 090079-EI to write-down the 2009 Pension

[73] Order No. 2009-81, issued February 17, 2009, in Docket No. 2009-36-E, In re: Petition of South Carolina Electric and Gas Company (Electric Operations) for Authorization to Defer Certain Charges to the Company's Financial Statements Resulting from the Impact of Recent Economic Developments on Pension Cost, p. 2.

[74] Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In re: Petition for a rate increase by Florida Power Corporation, p. 39.

Regulatory Asset. In the event such write-downs are insufficient to fully amortize the 2009 Pension Regulatory Asset, PEF shall not be allowed to seek recovery of this item through a base rate case prior to 2015. Until that time, the unamortized balance of the 2009 Pension Regulatory Asset will be included in rate base for purposes of earnings surveillance reporting. We also find that PEF shall not earn a carrying charge on this regulatory asset.

PEF argued that our ruling on this is binding and that any attempt to reargue our legal ruling would amount to an improper motion for reconsideration and thus should be rejected. A reconsideration standard is not appropriate here. Instead we are voting on whether to approve a regulatory asset for the deferral of 2009 pension expense with a fresh look as if a decision never took place. By Order No. PSC-09-0484-PAA-EI, issued July 6, 2009, in Docket No. 090145-EI, we memorialized our decision regarding the deferral of pension expenses. On July 27, 2009, the Intervenors filed a joint petition protesting the Order and identified and protested three issues. On August 3, 2009, PEF filed a Motion requesting that the matter be set for a hearing or in the alternative consolidated with the rate case docket. In its Motion, PEF argued that the three issues identified by the Intervenors were issues of law relating to the legal interpretation of the 2005 Stipulation. As such, PEF argued that the legal issues raised should be resolved on the basis of briefs and oral arguments. By Order No. PSC-09-0586-PCO-EI, issued on August 31, Docket Nos. 090145-EI and 090079-EI were consolidated for purposes of an evidentiary hearing.

OPC asserted that the creation of a regulatory asset for the deferral of pension expense is contrary to the plain language of the 2005 Stipulation. On September 28, 2005, in Order No. PSC-05-0945-S-EI, issued in Docket No. 050078-EI, we approved the 2005 Stipulation between the parties to PEF's last petition for a rate increase. Section 4 of the 2005 Stipulation provides that PEF may not petition for an increase in base rates that would take effect prior to the first billing cycle for January 2010, except as provided in Sections 7 and 10 of the 2005 Stipulation. Section 7 allows PEF to petition for a limited proceeding if its retail base rate earnings fall below a 10 percent ROE as reported on its monthly earnings surveillance report. Section 10 pertains to Storm Cost Recovery. The relevant portion of Section 4 of the 2005 Stipulation provides:

> 4. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof . . . [and] neither seek nor support any reduction in PEF's base rates and charges, including interim rate decreases, that would take effect prior to the first billing cycle for January 2010 . . . unless such reduction is requested by PEF. PEF may not petition for an *increase in base rates and charges* that would take effect prior to the first billing cycle for January 2010 . . . except as otherwise provided for in Sections 7 [Earning falling below 10 percent] and 10 [Storm Cost Recovery] of this Agreement. . . .

(emphasis added).

PEF's request to create a regulatory asset to defer pension expense is not a request to change rates and charges during the stipulation period; thus, Section 4 of the 2005 Stipulation is not applicable to the treatment of pension expenses. Furthermore, the 2005 Stipulation is silent as to the treatment of pension expenses. Accordingly, we find that the creation of a regulatory asset to defer pension expenses falls outside the scope of the 2005 Stipulation and does not violate the terms of the 2005 Stipulation.

OPC asserted that PEF's request to defer any level of pension expense that would otherwise be recorded in a year covered by the 2005 Stipulation violates the principle of retroactive ratemaking. Relying on Order No. PSC-98-1243-FOF-WS,[75] OPC argued that this violates the ratemaking principle of attempting to recover past expenses or revenues in future rates. We find that United Water is distinguishable from the facts in this case. In United Water, the utility was seeking a deferral of costs that had already been incurred, which violates SFAS 71. In this case, PEF is requesting a deferral of pension expense before the costs are incurred. The Florida Supreme Court has recognized that retroactive ratemaking occurs where a new rate is requested and applied retroactively.[76] The Florida Supreme Court has also stated that the general principle of retroactive ratemaking is that new rates are not to be applied to past consumption.[77] In this case, PEF is not requesting that new rates be applied to past consumption, rather, PEF is requesting a deferral of costs before the costs are incurred. Thus, we find that the deferral of any level of pension expense will not constitute retroactive ratemaking.

OPC also asserted that PEF's proposal amounts to a form of double recovery since the expenses incurred during the operational timeframe of the revenue sharing mechanism are presumed to be recovered under that plan. OPC argued that allowing the pension expenses to be deferred and recovered in rates set for 2010 forward will allow PEF to effectively recover them again.

FIPUG submitted that PEF's attempt to defer pension expense from the period covered by the 2005 Stipulation into a period beyond the 2005 Stipulation is an inappropriate shifting of costs into a future period. FIPUG asserted that allowing pension expenses to be deferred and recovered in rates set for 2010 forward would allow PEF to effectively recover such expenses twice -- once under the mechanism in place under the 2005 Stipulation and once in the future beyond the 2005 Stipulation. FIPUG concluded that this treatment constitutes an impermissible modification of the 2005 Stipulation and results in double recovery.

We do not agree with the Intervenors that PEF's proposed treatment of 2009 pension expense falls under the revenue sharing mechanism or that the creation of a regulatory asset for the deferral of this expense constitutes double recovery. Expenses are not relevant to the revenue sharing mechanism. The revenue sharing mechanism in the 2005 Stipulation is based on revenues, not earnings. Refunds are only made if revenues exceed a certain threshold and therefore the sharing mechanism is not affected by how much the Company may earn in any given period. In addition, by deferring the 2009 pension expense it is as if the expense never

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[75] See, Order No. PSC-98-1243-FOF-WS, issued on September 21, 1998, in Docket No. 971596-WS, In re: United Water Florida, Inc. (attempted deferral to future period of post retirement benefits costs that were unrecovered due to insufficient earnings denied as violative of prohibition against retroactive ratemaking), per curium aff'd, United Water Florida, Inc. v. Florida Public Service Commission, 751 So. 2d 578 (Fla. 1st DCA 2000).
[76] Citizens of the State of Florida v. Public Service Commission, 448 So. 2d 1024, 1027 (Fla. 1984).
[77] Gulf Power Company v. Cresse, 410 So. 2d 492, 493 (Fla. 1982).

occurred. With the deferral, PEF will not recover the costs in 2009 and thus there can be no double recovery.

Finally, in its brief OPC requested that we, on our own motion, adjust pension expense for purposes of setting rates in 2010 to a more appropriate level based on current market conditions. While certain parties questioned the reasonableness of PEF's projected 2010 pension expense, there is no evidence in the record regarding a more appropriate expense level. Moreover, no party raised an issue to make an adjustment to the Company's proposed jurisdictional pension expense for 2010 of $27.1 million. As a result, there is no basis for the action OPC has requested in its brief related to the 2010 pension expense.

For the reasons discussed above, we find that the deferral of pension expenses does not violate the terms of the 2005 Stipulation and Order, does not constitute retroactive ratemaking, and will not lead to double recovery. Accordingly, we find that only the retail portion of PEF's actual 2009 pension expense, estimated to be $31.5 million, shall be deferred as a regulatory asset (2009 Pension Regulatory Asset). On an annual basis, PEF shall use any pension expense levels below the allowance provided for in rates in the 2010 base rate proceeding in Docket No. 090079-EI to write-down the 2009 Pension Regulatory Asset. In the event such write-downs are insufficient to fully amortize the 2009 Pension Regulatory Asset, PEF shall not recover this item through a base rate case prior to 2015. Finally, we find that PEF shall not earn a carrying charge on this regulatory asset.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s Petition for Rate Increase is hereby denied as set forth herein. It is further

ORDERED that each of the findings made in the body of this Order are hereby approved in every respect. It is further

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

ORDERED that no refund of the interim increase approved by Order No. PSC-09-0413-PCO-EI, issued June 10, 2009, shall be required. It is further

ORDERED that the revised rates and charges shall become effective for meter readings made on or after February 10, 2010. It is further

ORDERED that Progress Energy Florida, Inc. shall review witness Pollock's alternatives related to the use of a load factor adjustment in the application of the IS-2 credit, and provide an analysis to this Commission for review when it submits its demand-side management programs for approval following the DSM goal setting proceeding. It is further

ORDERED that Progress Energy Florida, Inc. shall file, within 90 days after the date of the Final Order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records that will be required as a result of the findings made in this docket. It is further

ORDERED that upon expiration of the period for appeal these dockets shall be closed.

By ORDER of the Florida Public Service Commission this 5th day of March, 2010.

ANN COLE
Commission Clerk

By: Dorothy E. Menasco
Dorothy E. Menasco
Chief Deputy Commission Clerk

(S E A L)

KEF

CONCURRENCE AND DISSENT BY: CHAIRMAN ARGENZIANO

CONCURRENCE BY: COMMISSIONER SKOP

DISSENTS BY: COMMISSIONER EDGAR
COMMISSIONER STEVENS
COMMISSION KLEMENT

CHAIRMAN ARGENZIANO, concurring in part and dissenting in part:

I concur with the decisions of the majority with respect to issues 8-14, 47, 59, and 66, and dissent with respect to issues 15, 119, and 120.

I. Issues 8-14: Calculated Theoretical Reserves

Of the $97.35 million at stake on depreciation matters, $70 million of the requested increase is attributable to plant life-span decisions.[78] PEF failed to carry its burden of proof on these matters.

PEF's depreciation study failed to comply with Section (6)(f) of Rule 25-6.0436, Florida Administrative Code, in failing to provide an explanation and justification for each study

[78] TR 3197.

category of depreciable plant, identifying the specific factors that justify the life, salvage components, and rates being proposed. Further, PEF failed to comply with Section (8)(c) of Rule 25-6.0436, Florida Administrative Code, requiring its depreciation study to be filed no later than the filing of its minimum filing requirements.

PEF's first procedural misstep—failing to provide adequate explanation and justification—was reflected in its approach to depreciation in general. PEF's witness Robinson did not critically review plant life spans and come to an independent judgment on the proper figures; he only performed a depreciation study with the information provided to him by PEF.[79] PEF's witness Crisp also failed to reveal his reasoning: the witness provided a single page with average in-service and retirement dates, and a few general comments.[80]

Competing witnesses provided clear data suggesting longer life-spans were appropriate. Witness Pous testified that life spans for coal units range from 50 to 60 years;[81] referred to government data finding longer life spans for coal generating plants than what PEF proposed;[82] and noted that other utilities and regulatory commissions adopt life spans within the range of 55 to 68 years.[83] Witness Pollock agreed with witness Pous that other commissions adopt higher life spans than those proposed by PEF,[84] and noted that larger operators of coal plants have settled on 60 year life spans.[85] PEF's proposed life spans for its combined cycle units suffer from the same problem in that life spans used by other electric companies are significantly longer.[86]

PEF failed to identify specific factual circumstances to justify substantial deviations from evidence related to life spans. Instead, witness Crisp retreated to conclusory statements regarding PEF's "expertise and experience"[87] without providing a sampling demonstrating such. And although witness Crisp noted that PEF's planning process includes important factors (like the condition of each unit, plant reconfigurations, effects of the subtropical environment, and bulk system demands on generating plants),[88] he failed to identify data and specifics to support his position. The Intervenors quite capably noted this on cross, and when dissecting PEF's depreciation study.[89]

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[79] TR 1109, 1194; EXH 36, BSP 1138.

[80] EXH 216; TR 3403-3404; EXH 36, BSP 1360-1361.

[81] TR 2055-2056.

[82] TR 2055-2056.

[83] TR 2054-2055.

[84] TR 3198-3200; EXH 308.

[85] TR 3200.

[86] Gulf Power's estimated life span for its combined cycle units in Florida ranges from 34 to 40 years. EXH. 314; TR 3518-3519.

[87] TR 3399, 3403-3406, 3415.

[88] TR 3403-3406.

[89] OPC witness Pous and FIPUG witness Pollock argued that PEF's depreciation study failed to provide specific information regarding (1) the condition of PEF's generating facilities with respect to their life spans; (2) PEF's expertise in operating or maintaining its generating units; (3) substantiation that PEF has unique load demands or how load demands impact the life spans; (4) updates, changes, and reconfigurations made at each plant and how

II. Issue 15: Corrective Reserve Measures

PEF has over-collected depreciation expense in the amount of $694.4 million dollars. To remedy the intergenerational inequity thus created, the Commission should amortize this reserve back to customers over a period of four years.

There are two general options for correcting a material imbalance between theoretical and book reserve: implement revised remaining life depreciation rates that will recover the imbalance over the average remaining life of the assets; or amortize the imbalance over a short period of time. Depending on which way the imbalance falls, parties predictably argue that either the intergenerational inequity should be rectified over a short period or that the inequity should be smoothed out over the remaining life of the assets.

A review of Commission precedent reveals that there are three factors the Commission considers when deciding how to correct the imbalance: (1) the size of the intergenerational inequity (the greater the inequity the more compelling the need to address the imbalance over a shorter period); (2) the state of the ratepayers and the impact the proposed remedy would have on them (current state of the economy, ability to absorb costs, etcetera); and (3) the state of the company and the impact the proposed remedy would have on them (will the company earn a fair return, would a rapid amortization adversely affect the company's financial integrity to a *significant* degree—one that would justify a departure from the Commission's precedent of rectifying reserve imbalances as quickly as possible).[90]

In this case all three factors weigh in favor of correcting the reserve imbalance over a short period of time. The amount of the intergenerational inequity is high, at roughly 700 million dollars. The proposed remedy of amortizing a portion of the surplus to ratepayers—who have overpaid as of now by current estimates and are entitled to a refund as a matter of equity—could not come at a more opportune time considering the economy. PEF is an economically sound enterprise, and it was not demonstrated that a rapid amortization would adversely impact the company's financial integrity to a significant degree.

On the facts of this case the first two factors weigh in favor of correcting the intergenerational inequity over a short period of time. It is on the third factor where I disagree with my colleagues. Amortization of $694.4 million of the reserve back to customers over a

each affects the operating characteristics of the generating units with respect to life spans; (5) how renewable energy requirements may impact the life spans; and (6) the environmental risks PEF faces and how these risks may impact the life spans of the generating facilities. Pous TR 2179-2181; Pollock TR 3230-3232.

[90] PEF's reliance on Order No. PSC-98-1723-FOF-EI, issued December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study by Florida Power Corporation, regarding the Commission's concern for adjusting depreciation expense in response to economic conditions is entirely misplaced. In the 1998 case the Commission rejected FPC's request to prepay recovery of equipment on recovery/amortization schedules that already matched their expected dates of retirement. There the Commission was dealing with a request wholly outside the matching principle; here the Commission is operating squarely inside the matching principle and considering economic and firm-specific conditions as to how to resolve a reserve imbalance (surplus/deficit).

period of four years would not strain the company's financial integrity to such a degree as to justify a departure from the Commission's precedent of rectifying reserve imbalances as quickly as possible.

OPC witness Lawson addressed the financial implications of witness Pous' proposed amortization of PEF's reserve surplus. Witness Lawson demonstrated that amortizing the reserve imbalance would not have a detrimental effect on PEF's financial integrity or metrics; after amortization the metrics would remain within acceptable ranges for a BBB utility.[91] In contrast PEF failed to demonstrate that amortization of the surplus would adversely affect the company's financial integrity to a significant degree.

While I understand and share the caution of my colleagues in not wanting to adversely impact PEF's financial integrity to a significant degree, to my mind the majority's decision hinged on a fear resulting from worst-case speculation. When one party makes a sufficient evidentiary showing and the other cannot establish either a point or a narrow range where negative consequences are apparent, mere fear of possible negative consequences is not an adequate basis for decision. The Petitioner's burden was twofold in justifying a departure from the Commission's established precedent of rectifying reserve imbalances as quickly as possible: to present evidence regarding the financial consequences of remedying intergenerational inequities, and to present evidence demonstrating that a rapid amortization would adversely affect the company's financial integrity to a significant degree. In this case I was not convinced that amortization of the surplus would adversely affect PEF's financial integrity to a significant degree.[92]

Utilities should not benefit from systemically manipulating their depreciation expense through arbitrarily short service lives and less than accurate net salvage values. In order for there to be no gain to these accounting shenanigans, the Commission must rigorously enforce its policy of returning surplus depreciation expense to ratepayers as soon as possible. Further, this Commission has to make an effort to do so even when this may impact the utility's bottom line, subject to determination of the significance. It is reasonable to expect that a rational firm will plan to avoid undesirable consequences; if the company wants to avoid amortization of a reserve surplus over a short period, it should set reasonable service life and net salvage numbers. The Commission should not enable an accounting game where the public inevitably loses. Failing to refund the surplus only further allows utilities to stay one step ahead, collecting money from ratepayers before it is due.

III. <u>Issue 47: Return on Equity (ROE)</u>

[91] TR 2218, 2233-2235; EXH 177.

[92] Also, PEF's current financial metrics may be inflated insofar as they rely on previous over-collections of depreciation, and thus the difference resulting from this over-collection must be backed out to provide the proper comparison point for whether a rapid amortization adversely affects the company's financial integrity to a significant degree.

Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) establish the standards for determining the rate of return for regulated enterprises. The authorized return for a public utility should be (1) commensurate with returns on investment in other companies of comparable risk, (2) sufficient to maintain the financial integrity of the company, and (3) sufficient to maintain its ability to attract capital under reasonable terms. Id. The Commission was presented with conflicting evidence regarding the proper rate of return for PEF. It is the Commission's responsibility to evaluate the evidence and accord whatever weight it deems appropriate. United Tel. Co. of Fla. v. Mayo, 345 So. 2d 648, 654 (Fla. 1977); Shevin v. Yarborough, 274 So. 2d 505, 508-509 (Fla. 1973).

Because PEF is not a risky venture, because witness Woolridge's testimony was extremely creditable and convincing than that of competing experts, and because PEF has maintained its financial integrity and attracted capital on reasonable terms in the past while earning lower returns than the amount authorized in this case, I would have preferred a lower figure. Nevertheless, I agree with the Commission's decision to authorize a 10.5% ROE in this case.

PEF is not a risky venture. It is a monopoly earning a guaranteed profit by providing an essential service in an economic environment made virtually risk-free by legislative accommodation. In fact, PEF already collects about 60% of its costs through various "pass-through" mechanisms and cost-recovery clauses. Utilities run essentially no risk for (i) costs related to storm events, per section 366.8260, Florida Statutes (2009); (ii) renewable energy undertakings, per section 366.91, Florida Statutes (2009); (iii) nuclear costs, per section 366.93, Florida Statutes (2009); (iv) recoveries for environmental compliance costs, per section 366.8295, Florida Statutes (2009); (v) conservation costs, per section 366.82, Florida Statutes (2009); (vi) fuel and capacity costs, per Commission orders; and, if passed by the legislature in upcoming session, costs associated with expanded renewable portfolio standards.

The reduced risk associated with Florida's heralded constructive regulatory environment is a compelling consideration when setting an appropriate return on equity. I would prefer quantification of these advantages, possibly contrasted with the mechanisms in place in other jurisdictions, in order to more accurately adjust the returns of Florida firms. I suggest that the essentially risk free rate of treasury bills would serve as an appropriate comparator for the risk associated with the 60% of its costs Florida utilities are guaranteed because of legislative accommodation.[93]

The second reason supporting a lower ROE is that I found witness Woolridge's testimony far more creditable, thorough, and convincing than that provided by competing experts.[94]

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[93] See also Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for Rate Increase by Tampa Electric Company (Commissioner Argenziano, dissenting).

[94] Witness Woolridge's demeanor and responses demonstrated a thorough control of the material, and his analysis revealed a number of flaws in witness Vander Weide's analysis. For instance, witness Woolridge pointed out the significant upward bias in growth rates based on analysts' EPS forecasts included in witness Vander Weide's analysis. TR 3007-3008; EXH 166. To minimize the impact of this bias, witness Woolridge relied on a number of

Third, PEF maintained its financial integrity and attracted capital on reasonable terms in the past while earning lower returns than the amount authorized in this case. In 2007 PEF provided acceptable service while earning an ROE of 9.70%.[95] In 2008 PEF provided acceptable service while earning an ROE of 9.71%.[96] In both years PEF was able to attract capital under reasonable terms.[97]

Speculation on the reaction of rating agencies to a specific ROE is for the most part a red herring. The contemplated responses of rating agencies supported neither a reason to increase PEF's ROE as requested,[98] nor decrease the ROE below 10.5% as recommended by witness Woolridge.[99] There was no competent basis to believe that there would be either a debt rating upgrade if ROE was set at PEF's requested level, or a credit downgrade if PEF's rates were set using the ROE recommended by Dr. Woolridge. Accordingly, I gave little weight to predictions of what rating agencies will or will not do, and much more weight to the overall health of the company and its ability to provide utility services.

In sum, because PEF is not a risky venture, because witness Woolridge's testimony was extremely creditable, and because PEF has maintained its financial integrity and attracted capital on reasonable terms in the past while earning lower returns than the amount authorized in this case, an equity return of 10.5% is appropriate.

IV. Issue 59: Directors and Officers Liability Insurance

The Commission has decided that the fairest and most reasonable way to apportion the cost of directors and officers liability (DOL) insurance is to split the cost equally between ratepayers and shareholders. I do not disagree with that compromise, but would like to revisit the issue with greater analysis given the ratio of benefit to expense. Also, because I would prefer to see a consistent policy applied to the entities regulated by the Commission, and as the Commission has adopted a policy of disallowing the cost of DOL insurance in water and wastewater cases, I suggest that the cost of DOL insurance be borne by shareholders either entirely or in a degree more representative of the benefits received.

OPC witness Shultz was persuasive in noting that the crux of the matter in allocating expense is whether DOL insurance benefits ratepayers and, if so, how much. Other jurisdictions have reasoned similarly when disallowing 70-75% of the cost of DOL insurance.[100]

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measures for growth in his DCF analysis, not just EPS growth rates. TR 2978. Witness Woolridge also noted that witness Vander Weide used an inappropriately high risk-free rate in his DCF calculation. TR 3037-3038. And it came to light that witness Vander Weide improperly included an adjustment for flotation costs. TR 1368.

[95] TR 1846-47.

[96] TR 1846-47.

[97] TR 1847.

[98] TR 1272-73.

[99] TR 4160.

[100] TR 1953-1955.

V. Issue 66: Incentive Compensation

The commission is charged with the duty of setting rates which are "just, reasonable, compensatory, and not unfairly discriminatory." § 367.081(2)(a)1, Fla. Stat. (2009). In setting these rates the commission considers, among other things, operating expenses incurred by a utility. Id. Employee compensation is a subset of operating of expenses. As such, it is to be treated no differently than other elements of operating expense. Thus the proposition that the Commission has the authority to determine the reasonableness of compensation as an item of expense for ratemaking purposes is not disputed. Metro. Dade County Water & Sewer Bd., 200 So. 2d 831, 833 (Fla. 3d DCA 1967) (stating that "the Court does not question the right of a regulatory commission to determine the reasonableness of executive salaries as an item of expense for rate-fixing purposes").

As with all other expenses, it is the utility's burden to prove that its costs are reasonable. See Fla. Power Corp. v. Cresse, 413 So. 2d 1187, 1191 (Fla. 1982). There is no reason to depart from this burden when considering incentive compensation. A Commission finding based on competent, substantial evidence is not limited to a particular method in arriving at what constitutes such evidence. Nothing requires the Commission to accept self-serving benchmarking data at the expense of more compelling methods of proof. See In re Green Mountain Power Corp., 648 Vt. 378, 648 A. 2d 374, 380 (1994) (upholding without criticism the regulatory agency's conclusion that the requested increase was excessive considering the depressed economic climate; determining that it was appropriate for a regulatory agency to set levels of overall salary increases that ratepayers must bear); see also U.S. West Commc'ns v. Pub. Serv. Comm'n of Utah, 901 P.2d 270 (Utah 1995) (finding that the Commission's disallowance of a portion of a utility's compensation plan that increased shareholder wealth only and provided no real benefit to ratepayers was supported by substantial evidence).

In this case the Commission was presented with conflicting evidence regarding the reasonableness of the utility's incentive compensation package. It is the Commission's responsibility to evaluate the evidence and accord whatever weight to the conflicting opinions it deems appropriate. United Tel. Co. of Fla. v. Mayo, 345 So. 2d 648, 654 (Fla. 1977); Shevin v. Yarborough, 274 So. 2d 505, 508-509 (Fla. 1973).

PEF failed to prove that its compensation costs were reasonable for a number of reasons: (1) the documents PEF relied on failed probatively; (2) even if the compensation studies offered by PEF were admissible, the evidence thus adduced was unconvincing; (3) PEF failed to demonstrate that incentive compensation provides a benefit to ratepayers; rather, it was clear that incentive compensation solely benefits shareholders by aligning employees with shareholder interests. And, (4) even if ratepayers receive some benefit from incentive compensation, it is disproportionate to the corresponding expense.

FIPUG and the AG objected to moving into evidence three studies offered by PEF that aimed at establishing the reasonableness of PEF's compensation costs. I support their objections.[101] Expert witnesses can rely on "facts or data" not admissible in evidence in and of themselves, when forming their opinions, provided that the facts or data is of a type reasonably relied upon by experts in the relevant field in forming opinions on the subject. § 90.704, Fla. Stat. (2009). The relevant compensation benchmarking studies relied on by a human resources expert fit within those parameters. But in this case the utility expert conveyed the substance of otherwise inadmissible information. The testimony and corresponding exhibits served as a conduit for inadmissible hearsay and should have been excluded. Cf. Gerber v. Iyengar, 725 So. 2d 1181, 1185 (Fla. 3d DCA 1998) (concluding that the result of allowing the expert's testimony to act as a conduit for inadmissible hearsay is that the "highly impeachable statement . . . was presented for the jury's consumption without affording . . . an opportunity to cross-examine"); see also Riggins v. Mariner Boat Works, Inc., 545 So. 2d 430, 432 (Fla. 2d DCA 1989) (concluding that an expert opinion based on an inadmissible report unfairly prejudices and misleads by "emphasizing otherwise inadmissible evidence and placing an aura of truth upon a document which is legally unreliable").[102]

The aforementioned documents consisting of compensation studies are flawed because a number of the firms included had a portion of incentive compensation excluded from rates,[103] and the studies fail to demonstrate both the reasonableness of the costs and the reasonableness of the costs to be borne by ratepayers. Also, PEF's argument that incentive compensation is necessary to attract and retain employees was debunked by the fact that incentive compensation is not an influential factor affecting a worker's selection of a firm for employment.[104]

The incentive portion of PEF's compensation plan rewards shareholders and top executives at the expense of ratepayers;[105] the metrics used in computing incentive compensation

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[101] MS. KAUFMAN: We object to this document. Our objection is similar to the one I've stated. This is a -- this was transmitted by letter May 21, 2007. It didn't even go to Mr. DesChamps. But it's a survey that was conducted by a group. There's no witness here to sponsor this. There's no way that we can cross-examine the group or the preparer. We don't even know who the preparer of the document is. And I think as Ms. Bradley pointed out to you, a witness cannot get hearsay into evidence that's inadmissible by attempting to rely on it. So we object to the entry of this exhibit. We don't think that it is appropriate, and we don't think that it can be relied on for any purpose. If the company wanted this in evidence, they should have presented the witness who prepared it so we could cross-examine him and talk to him about how the study was performed and the data that supports it. TR 878-881. (Intervenors also objected on grounds of lack of authenticity.) TR 882-83.

[102] The Intervenors' objections, furthermore, highlight problems inherent to relying on benchmarking data assembled by an outside consultant for the purpose of establishing the reasonableness of executive compensation. That the data is arguably self-serving, easily manipulable, and not subject to cross-examination goes to the weight of the evidence, and, more generally, the weight that ought to be attached to the testimony of PEF's compensation witness.

[103] TR 1934, 3275-79. The exclusion of chunks of incentive compensation at other firms within the studies undermines the comparability of the results.

[104] TR 820, 1935-36.

[105] For example, PEF's Senior Management Performance Sub-Share Plan—the plan under which senior managers receive stock awards—ties the level of payout to total shareholder returns and the rate of growth of earnings per share for Progress during the performance period. These measures emphasize shareholder preferred results. TR 2311. PEF could not demonstrate that an appreciating stock price and increases in earnings per share benefit ratepayers. TR 843.

emphasized shareholder-preferred results.[106] The purpose of the incentive plan "is to promote the financial interests of the Company."[107] If shareholders want company executives bound to the single-minded pursuit of shareholders' interests, they should pay for it. Forcing the public to bear a cost which provides it no benefit is wrong.[108]

Finally, even if ratepayers receive some benefit from incentive compensation, the benefit is slight compared to the expense premium of $37.4 million dollars.

VI. Issues 119 and 120: Creation of a Regulatory Asset and Retroactive Ratemaking

PEF requested that the Commission authorize deferral of $52.9 million in pension expense. I dissent from the opinion of the majority. Granting PEF's request is a violation of a stipulation entered into by the parties and approved by this Commission; is contrary to Financial

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Also, half of the incentive pay realizable under the Employee Cash Incentive Plan varies with earnings per share, a metric that solely considers shareholder's interests. TR 3334. The other half depends on performance relative to 10 factors that vary according to business unit. TR 3330-34. These factors have innocuous labels—safety, environmental, service reliability, budget adherence, plant production, efficiency. But the labels did not match what was underneath them. Witness DesChamps was unable to identify the goals determining payouts for efficiency, transmission losses, distribution, and other measures that improved customer service. TR 3337.

As the hearings progressed it became increasingly clear that "incentive compensation" was little more than "additional compensation." In 2007 and 2008, 99.7% of eligible employees received incentive compensation. Witness DesChamps had no explanation for how all 5000 employees were so superior, conceded that he was not sure all the employees who received the benefits provided the level of service required by the measures, and admitted that he was not aware of a year in which incentive compensation was not paid. TR 3261, 3263-64.

[106] TR 1937, 3330-37.

[107] TR 1937.

[108] Other jurisdictions do not do it either. TR 1934, 1939-40. A few noted here for reference: Cal. Pub. Util. Comm'n, Application of Southern Cal. Edison Co., (2009) D.09-03-025, 2009 Cal. PUC LEXIS 165 (finding (1) that company failed to adequately support its bonus program and hence excluding amounts requested from revenue requirements; (2) that long-term executive compensation was closely tied to the company's stock performance and excluding the amounts from revenue requirements; and (3) that it is reasonable to limit executive compensation during difficult times); Conn. Dep't of Pub. Util. Control, Application of United Illuminating Co., Docket No. 08-07-04 (Feb. 4, 2009), 2009 Conn. PUC LEXIS 27 (reasoning that allocation of executive compensation should consider the interest of ratepayers and shareholders; limiting executive compensation to amounts that benefit ratepayers); Ga. Pub. Util. Comm'n, In re Petition of Atmos Energy Corp., Docket No. 27163 (Sept. 17, 2008), 2008 Ga. PUC LEXIS 115 (removing executive stock options because costs are incurred to (a) reward performance of stock price, and (b) financial performance and expenses are tied to the benefits of shareholders); Mass. Dep't of Pub. Util., Re New England Gas Co., D.P.U. 08-35, 271 P.U.R. 4th 1, 2009 WL 331668 (Mass. D.P.U.) (excluding corporate employee annual incentive compensation and executive officer bonus plan because the company failed to demonstrate benefits to ratepayers); Mich. Pub. Util. Comm'n, Case U-15244 (Dec. 23, 2008) (excluding costs of incentive compensation and bonuses from rates, finding that the utility failed to demonstrate that benefits to ratepayers outweighed the costs; excluding stock option expenses, performance shares, restricted stock, and executive deferred compensation because such expenses encouraged financial performance, which mainly benefits shareholders); Minn. Pub. Serv. Comm'n, Minnesota Power, Docket 4-2500-19796-2; E-015/GR-08-415 (Feb. 19, 2009) (limiting annual incentive payments to 15% of base pay); N.Y. Pub. Serv. Comm'n, Re Consolidated Edison Co. of N.Y., Case 07-E-0523 (Mar. 25, 2008), 264 P.U.R. 4th 34, 2008 WL 828108 (N.Y.P.S.C.) (determining ratepayers should not be responsible for funding incentive payments not linked to enhanced corporate productivity or improving safety and reliability of services).

Accounting Standard ("FAS") No. 87; has no basis in law or policy; and is an unlawful act of retroactive ratemaking.

Approving PEF's request to create a regulatory asset violates the 2005 Stipulation.[109] PEF is attempting to extract a piece of the costs for the period covered by the Stipulation and shift that piece into a future period. The Stipulation is the only way PEF may address matters within the period covered by the Stipulation: the Stipulation took into account expenses as a whole and set earnings accordingly. Later removing certain expenses and placing them in a future period—in response to an unfortunate turn for investments, a risk pensions are normally subject to—was not a part of the agreement. Moreover, approving PEF's request results in a double-recovery because the costs were included under the terms of the Stipulation, and the costs would also be included when the "costs [are] provided for in Commission approved base rates."[110]

Second, granting PEF's request is contrary to Financial Accounting Standard ("FAS") No. 87 – Employer's Accounting for Pension. The Financial Accounting Standards Board was unable to identify differences in circumstances that would make it appropriate for different employers to use fundamentally different accounting methods for pension plans. PEF's proposed deferral option is not available to unregulated companies.

Third, PEF's request has no basis in law or policy. The South Carolina order cited by PEF as legal precedent is not persuasive.[111] And there are no satisfactory policy reasons for accommodating PEF's request; in fact, policy considerations dictate that the Commission should reject PEF's request. For one, the economic downturn is not an exogenous event in the context of the request made: an unfortunate turn for investments is a risk pensions are normally subject to, and the downturn has affected all corporations' pension expenses in a like manner—not just PEF's, and not PEF's any more than anyone else's. Also, the Commission has a duty to ensure

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[109] The Commission approved the Stipulation and incorporated it into Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[110] Progress's Petition for Expedited Approval of the Deferral of Pension Expenses at 6.

[111] Order No. 2009-81, issued February 17, 2009, in Docket No. 2009-36-E, In re: Petition of South Carolina Electric and Gas Company (Electric Operations) for Authorization to Defer Certain Charges to the Company's Financial Statements Resulting from the Impact of Recent Economic Developments on Pension Cost. The South Carolina order expressly states that approval of SCE&G's request for deferral was predicated in part on the South Carolina Commission being able to avoid consideration of a rate case to increase base rates. Since PEF is currently before us with a request for an increase in base rates in Docket No. 090079-EI, PEF's request for deferral of the 2009 pension expense is not directly comparable with the situation in South Carolina. Another difference between the two cases rests with how pension expense has been treated for ratemaking purposes by the respective Commissions. In South Carolina, the revenue requirement approved in 2007 for SCE&G in its most recent rate case expressly recognized an annual pension benefit of approximately $4 million. This treatment has had the effect of reducing SCE&G's operating and maintenance (O&M) expense, thereby reducing customer rates. In contrast, the order approving the 1993 step increase in base rates for PEF included an annual pension expense of approximately $3.8 million. This treatment has had the effect of increasing PEF's O&M expense and thereby increasing customer rates. While the South Carolina decision recognized the sum of the annual amount of pension benefit expressly reflected in base rates with the projected pension expense in that same year (2009), PEF's request asks that the pension benefit from the prior year (2008) be added to the projected pension expense in 2009. These two requests are not the same.

the vitality of the purpose and effects of the stipulations it approves.[112] It is simply bad policy to make future stipulations vulnerable.

Fourth, granting PEF's request amounts to unlawful and prohibited ratemaking; it requires adding the negative pension expense of 2008 to the pension expense of 2009 to increase pension expense for 2010. See Order No. PSC-98-1243-FOF-WS, issued September 21, 1998, in Docket No. 971596-WS, In re: United Water Florida, Inc. (denying request for deferral to a future period of post-retirement benefit costs that were unrecovered due to insufficient earnings because approval would constitute retroactive ratemaking); see also City of Miami v. Fla. Pub. Serv. Comm'n, 208 So. 2d 249, 259 (Fla. 1968) (concluding that the Commission lacks authority for retroactive ratemaking).

COMMISSIONER SKOP, concurring specially with comment on Issue 33:

With respect to Issue 33 (Storm Damage Reserve Accrual), I concur with the majority and write separately to briefly articulate my basis for decision. In deciding this issue, it is important to recognize that the Progress Energy Florida, Inc. (PEF) storm damage reserve account is an unfunded reserve account. In simple terms, this means that any storm damage reserve funds collected from PEF ratepayers are not actually deposited and held within a restricted storm damage account, but rather exist only as an accounting entry representing an accrual to offset actual storm damage costs at a future point in time when such costs may arise. Accordingly, the storm damage reserve funds collected from PEF ratepayers provides additional free cash flow from operations that PEF may use for any purpose. While this is not necessarily harmful to PEF ratepayers, the storm damage reserve accrual is ultimately a discretionary expenditure which increases the PEF revenue requirement on a dollar for dollar basis. In the instant case, suspending the storm damage reserve accrual is justified because the suspension of the storm damage reserve accrual reduces the overall PEF revenue requirement, the existing PEF storm damage reserve balance was approximately $141.8 million dollars[113] at the end of 2009, and the Commission has proven mechanisms to address the timely recovery of storm damage costs via surcharge or securitization should such action be necessary.[114]

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[112] The Commission approved the Stipulation and incorporated it into Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc. (noting in final thoughts that "this Commission has a long history of encouraging settlements, giving great weight and deference to settlements, and enforcing them in the spirit in which they were reached by the parties").

[113] The existing PEF storm damage reserve balance of approximately $141.8 million dollars seems to provide an adequate measure of protection for PEF ratepayers based upon statistical analysis. At hearing, witness Harris testified that there was only a 3 percent probability of having storm damages greater than $140 million dollars in any given year, and only a 2.7 percent probability of having storm damages greater than $150 million dollars in any given year. (EXH 85)

[114] See Order No. PSC-05-0937-FOF-EI, issued September 21, 2005, in Docket No. 041291-EI, In re: Petition for authority to recover prudently incurred storm restoration costs related to 2004 storm season that exceed storm reserve balance, by Florida Power & Light Company; Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, In re: Petition for approval of storm cost recovery clause for recovery of extraordinary

In closing, there are opportunity costs and various tradeoffs involved in any decision. Given the prevailing economic conditions and the discretionary nature of the expense, the majority decision to suspend the storm damage reserve accrual was prudent. As with any discretionary expenditure, should economic conditions improve, I would support reinstating the PEF storm damage reserve accrual as necessary to achieve an appropriate storm damage reserve balance.

COMMISSIONER EDGAR, dissenting with the following opinion:

I respectfully dissent with the majority decision on Issues 33 and 68. PEF requested an increase in the annual accrual to the storm damage reserve. Our staff recommended against that requested increase. By a 3-2 vote, the majority voted to deny that request, but also went further and eliminated the annual reserve accrual in its entirety. I disagree with this decision.

In Order No. PSC-93-0918-FOF-EI, the Commission authorized a self-insurance mechanism for storm damage. As discussed in Order No. PSC-09-0283-FOF-EI, our current overall regulatory framework for the recovery of storm damage costs consists of three major components: an annual storm accrual, a storm reserve adequate to accommodate most, but not all, storm years, and a provision for utilities to seek recovery of costs that go beyond the storm reserve. Section 366.8260, Florida Statutes, permits utilities to recover all reasonable and prudent expenses for storm damage. In dockets addressing the damages resulting from the 2004 and 2005 hurricane seasons, we heard from thousands of residents and businesses about the impact on their lives and their local economy when electricity was unavailable post-severe storm. We also heard testimony opposing imposition of a monthly surcharge at the very time families and businesses were attempting to recover from the costs that they had incurred from storm damage (damage to property, housing, loss of revenue, etc.).

I believe that a small annual accrual to support a healthy and reasonable reserve is an important and beneficial component of our state's storm preparedness.

COMMISSIONER KLEMENT dissents on Storm Damage Reserve and Accrual for Property Damage, without opinion.

COMMISSIONER STEVENS dissents on Incentive Compensation, without opinion.

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expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.; Order No. PSC-06-0464-FOF-EI, issued May 30, 2006, in Docket No. 060038-EI, In re: Petition for issuance of a storm recovery financing order, by Florida Power & Light Company.

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.

Appendix 1

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 090079-EI
STIPULATED ISSUES

The parties have reached stipulations on several issues. These stipulations fall within one of two categories, as listed below. "Category 1" stipulations reflect the agreement of PEF, Staff, and at least one of the intervenors in this docket. Intervenors who have not affirmatively agreed with a particular Category 1 stipulation but otherwise take no position on the issue are identified in the proposed stipulation. "Category 2" stipulations reflect the agreement of PEF and Staff where no other party has taken a position on the issue.

Issue 2: Is PEF's projected test period of the twelve months ending December 31, 2010 appropriate? (Category 1 Stipulation)

Approved Stipulation: Yes. The twelve months ended December 31, 2010 is the appropriate test year. (AFFIRM, FIPUG, NAVY, and PCS did not affirmatively stipulate to this issue, and took no position.)

Issue 3: What are the appropriate inflation, customer growth, and other trend factors for use in forecasting? (Category 2 Stipulation)

Approved Stipulation: The appropriate inflation, customer growth and other trend factors for use in forecasting are those included in the MFRs, as filed.

Issue 4: Are PEF's forecasts of customer growth, KWH by revenue class, and system KW for the projected test year appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 5: Are PEF's forecasts of billing determinants by rate class for the projected test year appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 7: Should the current-approved depreciation rates, capital recovery schedules, and amortization schedules be revised? (Category 1 Stipulation)

Approved Stipulation: Yes. The parties' positions on how they should be revised are set forth in subsequent issues. (AFFIRM did not affirmatively stipulate to this issue, and took no position.)

Issue 16: What should be the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules? (Category 1 Stipulation)

Approved Stipulation: The implementation date should be January 1, 2010. (AFFIRM did not affirmatively stipulate to this issue, and took no position.)

Issue 22: Should the currently approved annual nuclear decommissioning accruals be revised? (Category 1 Stipulation)

Approved Stipulation: No. The issues associated with PEF's nuclear decommissioning study should be deferred from the rate case and addressed next year when FPL files its nuclear decommissioning study in December 2010. This will afford the Commission the opportunity to address the appropriateness of each companies' cost of nuclear decommissioning at the same time. PEF will not be required to prepare a new site-specific nuclear decommissioning study. However, PEF will be required to update the current study with the most currently available escalation rates. (AFFIRM, AG, and NAVY did not affirmatively stipulate to this issue, and took no position.)

Issue 23: What is the appropriate annual decommissioning accrual in equal dollar amounts necessary to recover future decommissioning costs over the remaining life Crystal River Unit 3 (CR3)? (Category 1 Stipulation)

Approved Stipulation: The issues associated with PEF's nuclear decommissioning study should be deferred from the rate case and addressed next year when FPL files its nuclear decommissioning study in December 2010. This will afford the Commission the opportunity to address the appropriateness of each companies' cost of nuclear decommissioning at the same time. PEF will not be required to prepare a new site-specific nuclear decommissioning study. However, PEF will be required to update the current study with the most currently available escalation rates. (AFFIRM, AF, and NAVY did not affirmatively stipulate to this issue, and took no position.)

Issue 25: Should any adjustments be made to rate base related to the Bartow Repowering Project? (Category 1 Stipulation)

Approved Stipulation: No. This stipulation does not prejudice the rights of any intervenor to contest the legality of including the Bartow project in rates during 2009. The new rates resulting from Docket No. 090079-EI, which will reflect the rate base and revenue requirement impact of the Bartow project, will supercede the rate change resulting from Order No. PSC-09-0415-PAA-EI as of the effective date of the new rates. (AFFIRM, and NAVY did not affirmatively stipulate to this issue, and took no position.)

Issue 26: Should an adjustment be made to reflect any test year or post test year revenue requirement impacts of "The American Recovery and Reinvestment Act" signed into law by the President on February 17, 2009? (Category 2 Stipulation)

Approved Stipulation: No.

Issue 34: Should any adjustments be made to PEF's fuel inventories? (Category 2 Stipulation)

Approved Stipulation: No adjustment should be made to PEF's requested level of non-nuclear fuel inventories in the amount of $347,235,000 (system). The appropriate jurisdictional amount is a fall-out based on the jurisdictional separation factor approved in Issue 89.

Issue 51: Has PEF made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 52: Has PEF made the appropriate test year adjustments to remove fuel and purchased power revenues and expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 53: Has PEF made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 54: Has PEF made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 74: Should an adjustment be made to bad debt expense for the 2010 projected test year? (Category 2 Stipulation)

Approved Stipulation: No.

Issue 77: What is the appropriate amount of nuclear decommissioning expense for the 2010 projected test year? (Category 1 Stipulation)

Approved Stipulation: The appropriate amount if $0. (AFFIRM did not affirmatively stipulate to this issue, and took no position.)

Issue 78: What adjustments, if any, should be made to the amortization of End of Life Material and Supplies inventories? (Category 2 Stipulation)

Approved Stipulation: No adjustments should be made.

Issue 79: What adjustments, if any, should be made to the amortization of the costs associated with the last core of nuclear fuel? (Category 2 Stipulation)

Approved Stipulation: No adjustments should be made.

Issue 86: What is the appropriate projected test year revenue expansion factor and the appropriate net operating income multiplier, including the appropriate elements and rates for PEF? (Category 2 Stipulation)

Approved Stipulation: The appropriate projected test year revenue expansion factor is 61.207% and the appropriate net operating income multiplier is 1.63381.

Issue 93: Is PEF's proposed methodology for treatment of unbilled revenue due to any recommended rate change appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 94: Is PEF's proposed charge for Investigation of Unauthorized Used appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 97: Should PEF's proposal to close the RST-1 rate to new customers be approved? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 103: Are PEF's proposed monthly fixed charge carrying rates to be applied to the installed cost of customer-requested distribution equipment, lighting service fixtures, and lighting service poles, for which there are no tariffed charges, appropriate? (Category 1 Stipulation)

Approved Stipulation: The methodology used by PEF to calculate the monthly fixed charge carrying rates is appropriate. To the extent any of the inputs used by PEF in the calculation are modified at the revenue requirements Agenda, PEF should recalculate the monthly fixed charge carrying rates using the approved inputs. (OPC, AFFIRM, AG, FIPUG, NAVY, and PCS did not affirmatively stipulate to this issue, and took no position.)

Issue 104: Are PEF's proposed delivery voltage credits appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes.

Issue 105: Are PEF's power factor charges and credits appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes. PEF's proposed power factor charge and credit of $0.25 kilovolt-ampere reactive (kVAR) is appropriate.

Issue 106: Is PEF's proposed lump sum payment for time-of-use metering costs appropriate? (Category 2 Stipulation)

Approved Stipulation: Yes. PEF's proposed $90 lump sum payment contained in the RST-1 rate for time-of-use metering costs is appropriate.

Issue 117: Should PEF be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records which will be required as a result of the Commission's findings in this proceeding? (Category 1 Stipulation)

Approved Stipulation: Yes. (AFFIRM did not affirmatively stipulate to this issue, and took no position.

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO 090079-EI
13-MONTH AVERAGE RATE BASE
DECEMBER 2010 TEST YEAR

SCHEDULE 1

Issue No		Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Nuclear Fuel - No AFUDC (Net)	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	10,381,341,000	(4,437,117,000)	5,944,224,000	151,145,000	25,723,000	126,566,000	6,247,658,000	(9,040,000)	6,238,618,000
	Commission Adjustments:									
24	Non-Utility Activities	(874,089)	(18,405)	(892,494)	0	0	0	(892,494)	0	(892,494)
25-S	Bartow Repowering	0	0	0	0	0	0	0	0	0
26-S	Recovery & Reinvestment Act	0	0	0	0	0	0	0	0	0
27	Plant in Service	0	0	0	0	0	0	0	0	0
28	Depreciation Study	0	46,549,627	46,549,627	0	0	0	46,549,627	0	46,549,627
29	Accumulated Depreciation & Amort.	0	0	0	0	0	0	0	0	0
30	CWIP	0	0	0	0	0	0	0	0	0
31	Property Held for Future Use	0	0	0	0	0	0	0	0	0
32	Nuclear Fuel	0	0	0	0	0	0	0	0	0
33	Storm Damage Reserve	0	0	0	0	0	0	0	17,329,872	17,329,872
34-S	Non-Nuclear Fuel Inventories	0	0	0	0	0	0	0	0	0
35	Rate Case Expense	0	0	0	0	0	0	0	(2,787,000)	(2,787,000)
36	Asset Retirement Obligations	0	0	0	0	0	0	0	0	0
37	Working Capital	0	0	0	0	0	0	0	0	0
69	Generation O&M Expense	3,479,776	(19,706)	3,460,070	0	0	0	3,460,070	0	3,460,070
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
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		0	0	0	0	0	0	0	0	0
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				0				0		0
				0				0		0
				0				0		0
				0				0		0
				0				0		0
---	Total Commission Adjustments	2,605,687	46,511,516	49,117,203	0	0	0	49,117,203	14,542,872	63,660,075
38	Commission Adjusted Rate Base	10,383,946,687	(4,390,605,484)	5,993,341,203	151,145,000	25,723,000	126,566,000	6,296,775,203	5,502,872	6,302,278,075

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 090079-EI
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2010 TEST YEAR

SCHEDULE 2

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	3,151,819,000	50.52%	12.54%	6.34%
Long-term Debt	2,637,596,000	42.28%	6.42%	2.71%
Short-term Debt	38,609,000	0.62%	5.25%	0.03%
Preferred Stock	19,881,000	0.32%	4.51%	0.01%
Customer Deposits - Active	111,734,000	1.79%	5.95%	0.11%
Customer Deposits - Inactive	1,129,000	0.02%	0.00%	0.00%
Deferred Income Taxes	389,297,000	6.24%	0.00%	0.00%
FAS 109 DIT - Net	(115,057,000)	-1.84%	0.00%	0.00%
Tax Credits - Weighted Cost	3,610,000	0.06%	9.74%	0.01%
Total	6,238,618,000	100.00%		9.21%
Equity Ratio	53.90%			

Commission Adjusted	($) Amount	($) Specific Adjustments	($) Adjusted Total	Ratio	($) Pro Rata Adjustments	($) Staff Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	3,151,819,000	(235,793,000)	2,916,026,000	46.74%	29,755,698	2,945,781,698	46.74%	10.50%	4.908%
Long-term Debt	2,637,596,000	180,112,000	2,817,708,000	45.17%	28,752,442	2,846,460,442	45.17%	6.18%	2.791%
Short-term Debt	38,609,000	2,636,000	41,245,000	0.66%	420,872	41,665,872	0.66%	3.72%	0.025%
Preferred Stock	19,881,000	1,358,000	21,239,000	0.34%	216,727	21,455,727	0.34%	4.51%	0.015%
Customer Deposits - Active	111,734,000	32,385,000	144,119,000	2.31%	1,470,618	145,589,618	2.31%	5.95%	0.137%
Customer Deposits - Inactive	1,129,000	328,000	1,457,000	0.02%	14,868	1,471,868	0.02%	0.00%	0.000%
Deferred Income Taxes	389,297,000	26,584,000	415,881,000	6.67%	4,243,731	420,124,731	6.67%	0.00%	0.000%
FAS 109 DIT - Net	(115,057,000)	(7,857,000)	(122,914,000)	-1.97%	(1,254,238)	(124,168,238)	-1.97%	0.00%	0.000%
Tax Credits - Weighted Cost	3,610,000	247,000	3,857,000	0.06%	39,358	3,896,358	0.06%	8.36%	0.005%
Total	6,238,618,000	0	6,238,618,000	100.00%	63,660,075	6,302,278,075	100.00%		7.881%
Equity Ratio	53.90%					50.31%			

Interest Synchronization Dollar Amount Change	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Long-term Debt	208,864,442	6.18%	12,907,823	38.575%	(4,979,193)
Short-term Debt	3,056,872	3.72%	113,716	38.575%	(43,866)
Customer Deposits	33,855,618	5.95%	2,014,409	38.575%	(777,058)
Tax Credits - Weighted Cost	286,358	8.36%	23,947	38.575%	(9,238)
					(5,800,117)
Cost Rate Change					
Long-term Debt	2,637,596,000	-0.24%	(6,330,230)	38.575%	2,441,886
Short-term Debt	38,609,000	-1.53%	(590,718)	38.575%	227,869
Tax Credits - Weighted Cost	3,610,000	-1.38%	(49,718)	38.575%	19,179
					2,688,934
TOTAL					(3,111,182)

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 090079-EI
NET OPERATING INCOME
DECEMBER 2010 TEST YEAR

SCHEDULE 3

Issue No.		Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes and ITCs	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	1,517,918,000	8,125,000	713,371,000	357,869,000	129,587,000	42,943,000	(2,523,000)	1,249,372,000	268,546,000
	Commission Adjustments:									
4-S	Revenue Forecast	0	0	0	0	0	0	0	0	0
5-S	Billing Determinants Forecast	0	0	0	0	0	0	0	0	0
24	Non-Utility Activities	0	0	0	(26,039)	(8,300)	13,246	0	(21,093)	21,093
49	Total Operating Revenues	0	0	0	0	0	0	0	0	0
50	Bartow Repowering	0	0	0	0	0	0	0	0	0
51-S	ECCR Revenues and Expenses	0	0	0	0	0	0	0	0	0
52-S	FAC Revenues and Expenses	0	0	0	0	0	0	0	0	0
53-S	CCR Revenues and Expenses	0	0	0	0	0	0	0	0	0
54-S	ECRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
56	Aviation Costs	0	0	0	0	0	0	0	0	0
57	Advertising Expenses	0	0	0	0	0	0	0	0	0
59	D&O Liability Insurance	0	0	(964,612)	0	0	372,099	0	(592,513)	592,513
60	Injuries & Damages Expense	0	0	(4,778,603)	0	0	1,843,346	0	(2,935,257)	2,935,257
61	A&G Office Supplies and Expenses	0	0	(1,298,435)	0	0	500,871	0	(797,564)	797,564
62	Productivity Improvements	0	0	0	0	0	0	0	0	0
63	Salaries and Employee Benefits	0	0	(1,454,000)	0	0	560,881	0	(893,120)	893,120
64	2010 Salary Increases	0	0	(10,146,776)	0	0	3,914,119	0	(6,232,657)	6,232,657
65	2010 Employee Position Increases	0	0	(3,454,626)	0	0	1,332,622	0	(2,122,004)	2,122,004
66	2010 Incentive Compensation	0	0	(32,854,378)	0	0	12,673,576	0	(20,180,802)	20,180,802
67	Employee Benefits Expense	0	0	(1,706,667)	0	0	658,347	0	(1,048,320)	1,048,320
68	Storm Damage Accrual	0	0	(14,922,000)	0	0	5,756,162	0	(9,165,839)	9,165,839
69	Generation O&M Expense	0	0	(9,004,955)	41,680	0	3,457,583	0	(5,505,692)	5,505,692
70	Transmission O&M Expense	0	0	(1,717,042)	0	0	662,349	0	(1,054,693)	1,054,693
71	Distribution O&M Expense	0	0	(8,924,197)	0	0	3,442,509	0	(5,481,688)	5,481,688
73	Rate Case Expense	0	0	(855,036)	0	0	329,830	0	(525,206)	525,206
74-S	Bad Debt Expense	0	0	0	0	0	0	0	0	0
75	Depreciation Study	0	0	0	(118,573,450)	0	45,739,708	0	(72,833,742)	72,833,742
76	Depreciation & Dismantlement Exp.	0	0	0	0	0	0	0	0	0
77-S	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0
78-S	End of Life M&S Inventories	0	0	0	0	0	0	0	0	0
79-S	Nuclear Fuel Last Core	0	0	0	0	0	0	0	0	0
80	Taxes Other Than Income	0	0	0	0	0	0	0	0	0
81	Parent Debt Adjustment	0	0	0	0	0	(14,487,526)	0	(14,487,526)	14,487,526
82	Income Tax Expense	0	0	0	0	0	0	0	0	0
83	Total Operating Expenses	0	0	0	0	0	0	0	0	0
85	Affiliated Transactions	0	0	0	0	0	0	0	0	0
88	Bartow Repowering	132,101,000	0	0	0	95,113	50,921,271	0	51,016,384	81,084,616
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	(3,111,182)	0	(3,111,182)	3,111,182
	Total Commission Adjustments	132,101,000	0	(92,081,327)	(118,557,809)	86,813	114,579,811	0	(95,972,512)	228,073,512
84	Commission Adjusted NOI	1,650,019,000	8,125,000	621,289,673	239,311,191	129,673,813	157,522,811	(2,523,000)	1,153,399,488	496,619,512

SCHEDULE 4

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 090079-EI
DECEMBER 2010 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

Line No.		(%) As Filed	(%) **ISSUE 86 Stipulated**
1	Revenue Requirement	100.000	100.000
2	Gross Receipts Tax	0.000	0.000
3	Regulatory Assessment Fee	(0.072)	(0.072)
4	Bad Debt Rate	(0.284)	(0.284)
5	Net Before Income Taxes	99.644	99.644
6	Income Taxes (Line 5 x 38.575%)	(38.437)	(38.437)
7	Revenue Expansion Factor	61.207	61.207
8	Net Operating Income Multiplier (100%/Line 7)	1.63381	**1.63381**

SCHEDULE 5

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 090079-EI
DECEMBER 2010 PROJECTED TEST YEAR
OPERATING REVENUE INCREASE CALCULATION

Line No.		As Filed	Commission Adjusted
1.	Rate Base	$6,238,617,000	$6,302,278,075
2.	Overall Rate of Return	9.21%	7.88%
3.	Required Net Operating Income (1)x(2)	574,577,000	496,619,512
4.	Achieved Net Operating Income	268,546,000	496,619,512
5.	Net Operating Income Deficiency (3)-(4)	306,031,000	0
6.	Net Operating Income Multiplier	1.63380	1.63381
7.	Operating Revenue Increase (5)x(6)	$499,997,000 *	$0 **

NOTES: * PEF's requested operating revenue increase of $499,997,000 includes the operating revenue requirements associated with the Bartow Repowering Project. PEF's current base rates include the $126,212,000 base rate increase for the Bartow repowering Project that was authorized in Order No. PSC-09-0415-PAA-EI, issued June 12, 2009, in Docket No. 090144-EI, In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc. The effective date for implementing the base rate increase was the first billing cycle in July 2009.

** For comparative purposes, the Bartow Repowering Project base rate increase of $126,212,000 should be added to any authorized base rate increase.