Ruth Nettles

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Subject: Docket No. 090079-EI, Docket No. 090144-EI, Docket No. 090145-EI
Attachments: FIPUG Post-Hearing Statement of Issues and Positions and Post-Hearing Brief 10.16.09.pdf

In accordance with the electronic filing procedures of the Florida Public Service Commission, the following filing is made:

a. The name, address, telephone number and email for the person responsible for the filing is:

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b. This filing is made in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc.; Docket No. 090144-EI, In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.; 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.

c. The document is filed on behalf of Florida Industrial Power Users Group.

d. The total pages in the document are 64 pages.

e. The attached document is FIPUG's Post-Hearing Statement of Issues and Positions and Post-Hearing Brief.

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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 FILED: October 16, 2009

THE FLORIDA INDUSTRIAL POWER USERS GROUP'S POST-HEARING STATEMENT OF ISSUES AND POSITIONS AND POST- HEARING BRIEF

The Florida Industrial Power Users Group (FIPUG),[1] by and through its undersigned counsel, pursuant to Order No. PSC-09-0638-PHO-EI, file this Post-Hearing Statement of Issues and Positions and Post-Hearing Brief.[2]

BASIC POSITION

In this case, PEF seeks a rate increase of **½ billion dollars**. Such an increase would no doubt be shocking no matter when sought, but it is truly stunning given the current state of Florida's economy, including the high unemployment and foreclosure rates in the state. While Floridians, including municipalities and school districts, have had to tighten their belts and forgo salary increases and other expenditures, PEF feels no need to do so. PEF's CEO Dolan acknowledges that the state is in a recession (Tr. 2636), and the company says "we understand the

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[1] FIPUG was granted intervenor status in Order No. PSC-09-0198-PCO-EI.

[2] Throughout this brief, Progress Energy Florida, Inc. is referred to as PEF. Progress Energy, Inc. is referred to as Progress. The Office of Public Counsel is referred to as Public Counsel. The Florida Retail Federation is referred to as FRF. References to the transcript are designated Tr., followed by the page number.

tough realities of the current economic situation," (Tr. 1778), but then seeks enormous increases in depreciation and storm reserve and asks the ratepayers to totally fund PEF's long term incentive plan. Further, PEF seeks an ROE of 12.54% -- higher than that sought by any utility in 2009. As Public Counsel states, PEF is not entitled to a rate increase; rather its rates should be decreased. FIPUG addresses each of the large substantive matters at issue below.

Cost of Service

There are many issues which the Commission will consider and address in this case. FIPUG would ask the Commission to look carefully at the unprecedented cost of service methodology —12 CP and 50% AD -- which PEF asks the Commission to adopt for the first time in its history. The method PEF touts is inappropriate and should not be adopted. PEF has failed to justify its request to change the method of allocation of production plant from the 12CP and 1/13th AD method.

The purpose of a cost of service study is to ensure that the costs of service are borne by those customers for whom the utility incurs such costs. The cost of service methodology PEF proposes fails to follow these cost causation principles.

The 12CP and 50% AD method PEF proposes fails to reflect cost causation because:

- It fails to recognize PEF's strong summer and winter peaks;
- PEF fails to consistently apply the methodology and does not follow the method's "costs follow benefits standard" to recognize that some variable costs also provide reliability benefits and should be allocated in the same way as demand costs;
- The higher costs of base load and intermediate capacity are not caused by average demand;
- The method severely undervalues capacity;
- The method double counts the coincident demand.

If the Commission does decide to replace the 12CP and 1/13th AD method, it should adopt the Average and Excess (A&E) method described in Mr. Pollock's testimony and initially endorsed by PEF witness Slusser.

Further, if an increase is granted, no rate schedule should receive an increase higher than 150% of system average base rate increase. Failure to appropriately apply this standard will result in some customers seeing increases of over 60%. Application of this policy has been the Commission's long-standing practice.

In addition, PEF's proposed rate design should be revised to:

- Assign no increase to non-fuel energy charges to more closely align the demand and energy charges to reflect the corresponding demand and non-fuel energy-related costs; and
- Increase the Interruptible Demand Credit to at least $10.49 per kW-Month to reflect the costs PEF avoids by providing this service, according to its own analysis.

Last, the Interruptible Demand Credit should not be load factor adjusted because 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. In lieu of measuring the amount of load curtailed, the Credit should be increased to at least $10.49 based on PEF's most recent cost-effectiveness analysis.

Depreciation

PEF has overstated its depreciation expense by using life spans which are too short for its coal and combined cycle units. PEF should use at least 55 years for its coal units and 35 years for its combined cycle units. In addition, PEF should reduce the surplus depreciation reserve by $100 million per year to correct the very large ($646 million) surplus in the depreciation reserve to restore generational equity; that is, current ratepayers should be charged only for the assets that are consumed to provide electric service. Further, this treatment of the large surplus will mitigate the impact of any rate increase.

<u>Capital Structure</u>

The Commission should reject PEF's proposal to impute debt associated with purchased power agreements. Rejection of this adjustment, as the Commission did in the Tampa Electric rate case, would change the common equity portion of PEF's capital structure to 50% on an adjusted basis. A 50% equity ratio is in line with the equity ratios of other comparably-rated electric utilities.

<u>Incentive Compensation</u>

During this difficult economic period, the Commission should look closely at PEF's proposal that ratepayers pick up the cost for <u>all</u> incentive compensation. Any incentive compensation that is based on achieving financial goals of the parent company of PEF should be disallowed. Such compensation benefits shareholders, not ratepayers. Therefore, FIPUG recommends the following disallowances:

- $2.6 million of incentive compensation budgeted for executives and senior management (executives);
- $15.6 million (or 50%) of the incentive compensation applicable to other management and non-management.

<u>O&M Adjustments</u>

PEF's test year O&M expense should be adjusted to correct a large spike in such expenses during the test year. In particular, the Commission should disallow $17.65 million related to transmission and distribution overhead line maintenance expenses and $15 million in production maintenance expense. The test year transmission and distribution O&M expenses PEF proposes represent an increase of 60% and 37%, respectively, compared to PEF's actual/projected expenses for the period 2006 – 2009. This includes increases of 47%

(transmission) and 44% (distribution) from 2009 to 2010. Similarly, steam and other generation maintenance expense would increase by 36% relative to 2009 and by 57% relative to the average of the most recent four-year period. These increases are excessive, have not been supported, and inappropriately increase test year expense.

Storm Accrual

The Commission should reject PEF's request to increase annual contributions to the storm reserve by $16 million per year. The current $133 million storm reserve balance is sufficient to cover all but the most serious of storm events. PEF's proposal is inconsistent with the Commission's existing framework, which is predicated upon a multi-faceted approach to funding storm damage. This approach does not rely solely on the storm reserve accrual to provide coverage for all storm damage. Even without any additional contributions, the storm reserve is adequate to provide coverage for the estimated annual average loss for the next eight years. Thus, contributions to the fund should cease.

ISSUES AND POSITIONS

TEST PERIOD AND FORECASTING

ISSUES 1-5 : *Due to PEF's withdrawal of its revised sales forecast and FIPUG's withdrawal of a portion of Witness Marz' testimony, these issues are no longer in dispute. (Tr. 13).*

QUALITY OF SERVICE

ISSUE 6: Is the quality and reliability of electric service provided by PEF adequate?

POSITION: *No position.*

DEPRECIATION STUDY

ISSUE 8: What are the appropriate capital recovery schedules?

POSITION: *The capital recovery schedules should be revised consistent with the recommendations of witnesses Pous and Pollock outlined in the following issues. Further, this should be a "fallout issue" that takes into account the Commission's consideration of, and explicit rulings on, the specific depreciation-related issues that OPC and other parties have raised and addressed through testimony and participation in this proceeding.*

ISSUE 9: Is PEF's calculation of the average remaining life appropriate?

POSITION: *No. PEF has understated the life spans for its coal and combined cycle plants and overstated its depreciation requirements.*

ISSUE 10: What life spans should be used for PEF's coal plants?

POSITION: *Based on industry experience and specific examples, the Commission should use a life span of at least 55 years for its coal plants.*

ISSUE 11: What life spans should be used for PEF's combined cycle plants?

POSITION: *Based on industry experience and specific examples, the Commission should use a life span of at least 35 years for its combined cycle plants.*

ISSUE 12: What are the appropriate depreciation parameters (remaining life, net salvage percent, and reserve percent), amortizations, and resulting rates for each production unit, including but not limited to coal, steam, combined cycle, etc.?

POSITION: * See Issues 9, 10, 11, 13.*

ISSUE 13: What are the appropriate depreciation parameters (remaining life, net salvage percent, and reserve percent), amortizations, and resulting rates for each transmission, distribution, and general plant account?

POSITION: *Agree with OPC.*

DISCUSSION

The issues in this section relate to what amount, if any, PEF should be permitted to include in rates for purposes of depreciation. PEF seeks to include $97.35 million in depreciation costs in rates. (Tr. 1192). This amount represents almost 25% of PEF's revenue request. Of this amount, $70 million of the increase is due to increased production depreciation rates attributable to life span decisions. (Tr. 3197).

(Tr. 1141, emphasis supplied). Mr. Robinson's reliance on his workpapers to meet the rule's requirements is misplaced. Such workpapers were provided only when requested by other parties in discovery. [3] (Tr. 1139). A plain reading of the rule makes it clear that the information required by the rule must be submitted when the study is filed.

Nor can PEF witness Crisp bolster Mr. Robinson's study. When PEF witness Crisp took the stand on direct, he acknowledged that no part of his direct testimony, which relates solely to the development and results of PEF's load forecast, (Tr. 990), supports the depreciation study. (Tr. 986). Witness Crisp's direct testimony. Further, the only MFRs sponsored by witness Crisp are shown on Exhibit No. 77 and relate only to PEF's forecast and the models that underlie that forecast. (Tr. 991, 3417).[4]

In addition, witnesses Pous and Pollock reviewed the PEF depreciation study. Both confirmed that the study contained no specific information supporting PEF's proposed life spans, no analysis as to trends regarding decreased reliance on fossil fuels and increased regulation of carbon, no specific information regarding the condition of PEF's generating facilities, no specific information as to PEF's expertise in the operation of its generating units, no specific information as to PEF's experience in the maintenance of its units, no information on PEF's unique load demands, no specific information on updates, changes or reconfigurations at PEF's plants, no specific information on the impact of renewable energy, and no specific information as to environmental risks. (Tr. 2179-2181; 3230-3232). [5]

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[3] Staff was required to send over 160 interrogatories and requests for production to PEF. (Tr. 1221-1222).

[4] Even when witness Crisp took the stand on rebuttal, he had not seen the depreciation study, (Tr. 3417-3418), nor had he ever reviewed the Commission's depreciation rule. (Tr. 3437).

[5] As witness Pous testified: "I defy you or anybody else to go to the company's depreciation study and find the basis for their proposals. Not only is it not in there, it's not in his work papers, its' not in responses to data requests where I asked for this type of information. I have basically numerical analysis that the company has presented." (Tr. 2193).

PEF's depreciation study, on its face, fails to meet the requirements of the Commission's depreciation rule and should be rejected on that basis alone.

Life Spans

As to the substance of PEF's depreciation study, FIPUG's focus is on the life spans PEF proposes for its depreciation rates. As the NARUC Depreciation Manual states:

> … the final retirement date is the most important factor in the determination of a depreciation rate for the lifespan of properties.

(Exhibit No. 275 at 146). Witness Robinson agreed that the selection of the correct life span is a critical component of depreciation rates. (Tr. 1192). The shorter life used for a depreciation parameter, the higher the depreciation cost. As witness Pollock testified, "it is critical that appropriate average life span be used to develop the depreciation rates so that present and future ratepayers are treated equitably." (Tr. 3196).

While PEF sponsored witness Robinson as its depreciation expert, PEF did not ask witness Robinson for his opinion about the appropriate lifespan for its assets, (Tr. 1194), despite the fact that this is the "most important factor in the determination of a depreciation rate of the lifespan of properties." Witness Robinson testified: ""we weren't tasked with the specific task of, well, you need to determine the proper retirement date for these plants." (Tr. 1194).

In addition, when preparing his depreciation study, it does not appear that witness Robinson looked behind the positions the company provided to him. For example, though witness Robinson cites in his testimony the fact that prior and prospective factors affect plant in service (Tr. 1105), when questioned about such factors, he could not identify a single specific factor. (Tr. 1196-1197). Witness Robinson also identified requirements of governmental authorities as important matters to consider when deciding upon appropriate depreciation rates (Tr. 1107); however, when questioned about what specific requirements he was referring to he had no examples. (Tr. 1198-1199). Witness Robinson reviewed no manufacturers' information on any of the plants in his study. (Tr. 1199-1200). While PEF attempted to maintain that only the PEF units should be considered and that the Commission should not subsitute its judgment for the company's, (Tr. 3399), it is clear that there is little information in the record from which to reach a conclusion.[6]

Coal Units

PEF proposes a 52-year life span for its coal units. Such a life span is understated and PEF has provided no justification for this life span other than generalized comments, which are not supported, about the "uniqueness" of the units. (Tr. 3199). As noted by witness Pollock and witness Pous, the life spans PEF proposes are shorter than the average lives of coal-fired plants as determined in other proceedings. For example, the following lives have been approved for other coal-fired plants:

- 60 years for Indiana-Michigan Power company's Tanner Creek Units 1 through 4 and for its Rockport Unit 1 (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007);
- 55 years for coal plants operated by Southwestern Public Service Company (New Mexico Public Regulatory Commission, Case No. 07-00319-UT, *Order*, August 26, 2008);
- 59 to 68 years for coal units owned by AmerenUE (Missouri Public Service Commission, Cause No. ER-2007-0002, *Order,* May 22, 2007);
- 61 years for coal units owned by Rocky Mountain Power (Wyoming Public Service Commission, Docket No. 20000-257-EA-6, *Record No. 10794*, June 12, 2008);
- 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission, Cause No. PUD 200600285, *Order No. 545168*, October 9, 2007); and
- 55 years for Georgia Power Company's Plant Scherer Units 1-3 (Georgia Public Service Commission, Docket No. 25060-U, Document 103566, 2007 Rate Case).

[6] PEF witness Robinson agreed that if there is limited data, consideration of information from other jurisdictions is appropriate. (Tr. 1160). Such is the case here, as witness Robinson had no specific knowledge about PEF's units.

(Tr. 3199-3200).

Further, the two biggest operators of coal units in the nation, American Electric Power Company and The Southern Company, have determined that life spans of 60 years or more are achievable.[7] Gulf Power Company extended the lives of the Plant Crist and Plant Smith units to 65 years.[8] PEF has understated the life span of its coal units, which results in increased depreciation costs which PEF wants ratepayers to bear. (Tr. 3199-3200). The Commission should use a life span of at least 55 years for PEF's coal units. (Tr. 3201). Use of this more reasonable life will result in an annual reduction in revenue requirements of $4.1 million. (Tr. 3206).

<u>Combined Cycle Units</u>

PEF has proposed an average life span for its combined cycle units of 31 years. As with its coal units, PEF's testimony on its support for this life span is woefully insufficient. PEF has not explained why it cannot operate these units for much longer than 31 years (30 years for its newest, most efficient Hines and Bartow units). Since these are the most efficient units on PEF's system, it should be economic to maintain them in good operating condition for much longer than 31 years. (Tr. 3202). While PEF attempted to vaguely suggest that its combined cycle units had some unique mechanical and operational characteristics, this claim was dismissed by PEF witness Sorrick, PEF's Vice President Power Generation, who acknowledged that such units are not one of a kind units. (Tr. 478).

As with its coal units, industry practice demonstrates that such units actually have a much longer life span. For example, the following lives have been approved for other combined cycle plants:

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[7] Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007, Florida Public Service Commission, Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI,* January 2, 2007.
[8] Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI,* January 2, 2007.

- 40 years for PacifiCorp/Rocky Mountain Power's CC units (Utah Public Service Commission, Docket No. 07-035-13 and Public Utility Commission of Oregon UM 1329, *Order No. 08-327*, June 17, 2008);
- Over 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission Cause No. 200600285, *Order No. 545168*, October 9, 2007);
- 35 years for Nevada Power Company's Silverhawk and Lenzie CC units (Nevada Public Utilities Commission, Docket No. 06-11023, Modified Order of July 17, 2007);
- 35 years for Georgia Power Company McIntosh CC units (Georgia Public Service Commission, Docket No. 25060-U Document 103566, 2007 Rate Case).

Further, in a study of capacity needs, the Michigan Public Service Commission (MPSC) used a 40-year life span for new CC units.[9] (Tr. 3202-3203). As to Florida utilities, Gulf Power recently extended the life of Plant Smith Unit 3 to 34 years.[10] (Tr. 3203). While conservative in light of the non-Florida examples cited above, this Florida example further demonstrates the unreasonableness of PEF's proposed life spans.

The Commission should use a life span of at least 35 years for PEF's combined cycle units. (Tr. 3203). Use of this more reasonable life will result in an annual reduction in revenue requirements of $13.1 million. (Tr. 3205).

ISSUE 14: Based on the application of the depreciation parameters that the Commission has deemed appropriate to PEF's data, and a comparison of the calculated theoretical reserves to the book reserves, what are the resulting differences?

POSITION: *PEF has a surplus depreciation reserve in excess of $646 million.*

ISSUE 15: What, if any, corrective reserve measures should be taken with respect to the differences identified in the Issue 14?

POSITION: *To compensate for the huge reserve surplus that PEF has, the Commission should order PEF to implement a $100 million annual depreciation expense adjustment. PEF should credit depreciation expense and debit to the bottom line depreciation reserve by at least $100 million per year.*

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[9] MPSC Docket No. U-14231.

[10] Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007.

Issues 14 and 15 relate to the large surplus depreciation reserve that PEF has resulting from its collection of depreciation expense from ratepayers. PEF's depreciation study (Exhibit No. 84), based on its assumed average and remaining service lives of its investments and the projected book value as of December 31, 2009, shows its book depreciation reserve is $646 million higher than its "theoretical reserve."[11] (Exhibit No. 84, Table 5F). In other words, PEF has accrued a $646 million reserve surplus.[12]

Despite PEF's protestations to the contrary, this is a material variance. (Tr. 2178). Witness Pous testified:

> In this case we're talking about $646 million, as admitted to by the company. I believe that is substantial and material in anybody's book. I've quantified it at 858 million, and I believe it's actually higher than that because of other adjustments I have proposed.

(Tr. 2179).

The purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility plant. With the large depreciation surplus, the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. Thus, PEF's depreciation rates are not fair or equitable, (Tr. 3198), and this excess reserve perpetuates intergenerational inequity.

The *NARUC Depreciation Manual* recognizes that there are several ways to deal with a reserve imbalance:

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[11] The theoretical reserve is the amount necessary to allow recovery of the existing investments over their projected remaining life spans.

[12] It is important to recognize that the $646 million surplus reserve is dependent on PEF's proposed life and salvage parameters. The theoretical reserve calculation is based on PEF's remaining life proposals. If the remaining life is understated, as the evidence demonstrates, the theoretical reserve will be overstated causing the reserve surplus to be understated. (Tr. 3197-3198).

> A reserve imbalance exists when the theoretical reserve is either greater or less than the actual reserve. If changes are made to the estimated service life and net salvage, creating a reserve imbalance, a decision must be made as to whether and how to correct the reserve imbalance. Should the imbalance be amortized (debited or credited) to the current depreciation expense over a short period of time; or should a remaining life depreciation rate be used to spread the imbalance over the future remaining life of the plant; or should future depreciation rates be adjusted to reflect the current estimated service life of the plan leaving the decision to adjust the reserve for the future?

(Exhibit No. 311; Tr. 3980). One of the recognized methods is the one witness Pollock recommends.

In order to compensate for the huge reserve surplus, as well as mitigate the proposed $0.5 billion rate increase, the Commission should order PEF to implement a $100 million annual depreciation expense adjustment. That is, PEF should credit depreciation expense and debit to the bottom line depreciation reserve by at least $100 million per year. This treatment should continue until PEF files its next depreciation study. Assuming PEF's next depreciation study is filed in 2012 (three years from the filing date of this case), the book reserve would be reduced by an additional $300 million. This would still leave nearly $0.5 billion in excess book depreciation reserve. (Tr. 3204).

PEF's claim that amortization of the reserve surplus is retroactive ratemaking is without merit.[13] Retroactive ratemaking involves going back in the past and changing an approved rate. As the Court found in *City of Miami v. FPSC*, 208 So.2d 249, 259-260 (Fl. 1968), retroactive ratemaking involves the application of new rates to past consumption. In this case, the main issue is the setting of PEF's *prospective* depreciation rates. Such rates will be applied going forward and amortization of the surplus reserve going forward is not retroactive ratemaking. As

[13] The *NARUC Depreciation Manual* suggests that the use of an annual amortization over a short period of time is a common option for eliminating a materials reserve imbalance. (Tr. 2176-2177).

witness Pous testified, calculation of the theoretical reserve is a prospective looking theoretical reserve calculation. (Tr. 2153, 2156, 2176).

Further, in addition to the way depreciation was handled in the last PEF rate case, [14] there is ample precedent for this treatment of a reserve surplus. The correction of a reserve surplus in this case is conceptually the same as prior Commission actions allowing Florida Power & Light Company (FPL) to correct reserve deficiencies. For example:

- FPL was to book $126 million (in accord with preliminary implementation approved in Order PSC-95-0672-FOF-EI), an additional $30 million commencing in 1996, and additional expense in 1996 and 1997 equal to 100% of base rate revenues produced by retail sales between its "low band" and "most likely sales forecast" for 1996, and at least 50% of the base rate revenues produced by retail sales above FPL's most likely sales forecast for 1996 to correct a $175.3 million deficiency in the nuclear depreciation reserve and to correct the reserve deficiency existing in FPL's other production facilities, which was calculated to be $60.3 million as of January 1, 1994;[15]
- FPC was ordered to amortize the gain realized from the sale of a combustion turbine from Port St. Joe to be used to offset the reserve deficiency at the Suwanee Peaking Plant.[16]

More recently, the Commission adopted a similar approach for FPL to correct a reserve surplus. The Commission stated that:

> FPL has the option to amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Stipulation and Settlement and as specified therein. Depreciation rates and/or capital recovery schedules will be established pursuant to the comprehensive depreciation studies as filed in March 2005 and will not be changed during the term of the Stipulation and Settlement.[17]

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[14] It should also be noted that in the settlement of PEF's last rate case, PEF took a charge to its depreciation expense of $250 million per year. While FIPUG agrees that there is give and take in settlements, the Commission did not find any regulatory impediment to this treatment for depreciation or it would not have approved the settlement. (Tr. 3984).

[15] Docket No. 950359-EI, *Order No. PSC-96-0307-PHO-EI.*

[16] Docket No. 971570-EI, *Order No. PSC-98-1723-FOF-EI.*

[17] Docket No. 050188-EI, *Order PSC-05-0902-S-EI* at ¶ 8.

Since PEF has a huge reserve surplus, similar adjustments are appropriate and necessary to restore generational equity and to help mitigate the impact of the proposed base rate increases. (Tr. 3204-3205).

FOSSIL DISMANTLEMENT COST STUDY

ISSUE 17: Should the current-approved annual dismantlement provision be revised?

POSITION: * Yes. Agree with OPC.*

ISSUE 18: What, if any, corrective reserve measures should be approved for fossil dismantlement?

POSITION: *No position.*

ISSUE 19: What is the appropriate annual provision for dismantlement?

POSITION: *If the Commission decides to address fossil dismantlement in this proceeding, the Company's costs should be reduced by 60%.*

ISSUE 20: Are PEF's assumptions in the fossil dismantlement study with regard to site restoration reasonable?

POSITION: *No. FIPUG agrees with OPC.*

RATE BASE

ISSUE 24: Has the company removed all non-utility activities from rate base?

POSITION: *No. Rate base and associated accumulated depreciation should be reduced to account for the erroneous wholesale direct allocation to the City of Tallahassee's ownership in CR3.*

ISSUE 27: Is PEF's requested level of Plant in Service for the projected 2010 test year appropriate?

POSITION: *No. Plant in service should be adjusted ($2,312,287) to properly allocate general plant to wholesale operations.*

ISSUE 28: What adjustments, if any, should be made to accumulated depreciation to reflect revised depreciation rates, capital recovery schedules, and amortization schedules resulting from PEF's depreciation study?

POSITION: * See Issues 9 -13.*

ISSUE 29: Is PEF's requested level of Accumulated Depreciation and Amortization in the amount of $4,437,117,000 for the 2010 projected test year appropriate?

POSITION: *No. The adjustments Intervenors recommend should be made*

ISSUE 30: Is PEF's requested level of CWIP – No AFUDC in the amount of $151,145,000 for the projected 2010 test year appropriate?

POSITION: * No position.*

ISSUE 31: Is PEF's requested level of Plant Held for Future Use in the amount of $25,723,000 for the projected 2010 test year appropriate?

POSITION: *No.*

ISSUE 32: Is PEF's requested level of Nuclear Fuel – No AFUDC (net) in the amount of $126,566,000 for the projected 2010 test year appropriate?

POSITION: * No. PEF's proposed nuclear fuel balance should be reduced ($26,752,411) as a result of the company's failure to provide any justification for the large increase in test year nuclear fuel.*

ISSUE 33: Should an adjustment be made to PEF's requested storm damage reserve, annual accrual of $14.9 million, and target level of $150 million?

POSITION: *Yes. PEF's requested storm reserve accrual of $14.9 million (jurisdictional), $16 million (system) should be suspended concurrent with the effective date of the new rates in this case. No further accruals should be made to the storm reserve as the current reserve balance is sufficient to provide for coverage of the expected annual loss (EAL) and also provides coverage for all category 1 storms.*

DISCUSSION

Pursuant to rule 25-6.0143, Florida Administrative Code, electric utilities may establish a "separate subaccount . . . that portion of Account No. 228.1, which is designated to cover storm-related damages to the utility's own property or property leased from others that is not covered by insurance." PEF has established such a reserve and the balance in the reserve is approximately $133 million. (Tr. 2317). Currently, ratepayers contribute $6 million per year to this reserve and PEF has requested that this amount be increased to $16 million per year.

In the recent Tampa Electric rate case, the Commission set out the framework for the recovery of prudent storm expenses:

> We have established a regulatory framework consisting of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all storm years; and, (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve.[18]

Rather than relying on this regulatory framework, PEF seeks to augment its cash flow by increasing storm reserve collections. When money is collected pursuant to the storm reserve accrual, it is not set aside in a dedicated fund. As PEF witness Toomey described, the money is simply shown as "a reserve on the books....). (Tr. 1809-1810). Mr. Toomey furthered admitted, when questioned by Commissioner Skop, that such monies are

> cash that is free to go anywhere, theoretically. It could be swept up to pay dividends at the corporate level, swept up to the corporate level or used for other operating expenses....the company is free to use that incoming cash any way it sees fit within corporate operations...

(Tr. 1812). Ratepayers see no benefit from an increase in the fund; in fact, what they will see is higher rates. In contrast, the increase will benefit PEF by increasing its cash flow. (Tr. 2323).

This Commission has recognized that the ultimate risk for payment of prudent storm costs falls to the rate payers under a "pay me now" or "pay me later" scenario:

> . . . under the current approach to the recovery of storm restoration costs, the risk associated with a lower reserve level (i.e., the possibility of storm restoration costs exceeding the Reserve, leading to subsequent customer charges) and the risk associated with a higher reserve level (i.e., paying charges now for storm restoration costs that do not materialize) is completely borne by FPL's customers. The customers represented in this proceeding have made clear that they would rather pay to fund the Reserve to a lower level now and risk future rate volatility than pay to fund the Reserve to a higher level before future storm restoration costs have been incurred.[19]

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[18] In re Tampa Electric Company, Docket No. 080317-EI , *Order No. PSC-09-0283-FOF-EI* at 17.
[19] In re Florida Power & Light Company, Docket No. 060038-EI, *Order No. PSC-06-0464-FOF-EI* at 25).

As in the FPL case, ratepayers in this case have made it clear that they would rather "pay later" for any future storm damage.

PEF acknowledged that the Commission has set up an appropriate framework to allow for the recovery of prudent and reasonable storm expenses. (Tr. 1815). PEF further acknowledged that it has no reason to believe that the Commission will not allow recovery of such expenses in the future. (Tr. 1815 -1816). PEF is at little or no risk for recovering storm restoration costs regardless of the amount in the storm reserve. (Tr. 2318).

Further, PEF has a line of credit and credit facilities available to it to allow it to handle storm expenses. (Tr. 1045, 4181). In addition, PEF's parent has a credit facility worth about $800 million. (Tr. 4182).

PEF's request to increase the storm reserve charge should be denied for several reasons. First, as discussed above and as the Commission recognized in the FPL Order, consumers would rather pay for the storm damage after it occurs. Ratepayers prefer not to "lend" their cash to PEF, especially in these difficult economic times. The storm fund is not a dedicated fund, but is simply free cash to fund PEF's operations.

Second, PEF wants to collect enough money pursuant to the storm accrual charge to provide coverage for *all storms* that might occur. This is an unreasonable approach and inconsistent with this Commission's approach to storm recovery.

While PEF retained witness Harris to discuss storm issues, his role for PEF was *not* to recommend any specific accrual level but to present various probabilities. (Tr. 1011). Witness Harris' study does not address whether this is the appropriate time for ratepayers to pay more for the storm accrual. (Tr. 1056). The Hurricane Loss and Reserve Performance Analyses (Study) PEF witness Harris presented takes into account all manner and strength of storms. (Tr. 1012;

Exhibit No. 85). It includes all storms, including the most severe storm to affect PEF's service territory, the 1921 Category 3 hurricane that made landfall in Pinellas County.

In other words, PEF has assumed that the storm reserve should be adequate to cover damage from *all storms*. The current $133 million reserve balance covers all Category 1 hurricanes and most Category 2 storms. Thus, it is sufficient to cover eight consecutive years in which the expected annual loss (EAL) chargeable to the storm reserve occurs. (Tr. 2320). The storm reserve is not intended to cover every conceivable situation.

It is unnecessary and unreasonable to set the storm accrual at a level to cover all storms. As explained above, the storm reserve and associated accrual are only part of the framework for recovering storm restoration costs. The Commission has demonstrated its ability and willingness to promptly consider and act upon a utility request to recover storm costs. As such, the storm reserve need not cover all storms. To do so would impose an unnecessary added burden on ratepayers. (Tr. 2322).

Rather, what is needed is a reasonable accrual and a reasonable reserve designed to cover the expected damage from the more common (but not all) storm events. In this instance, PEF is seeking to establish the reserve at a level designed to provide for coverage for all storms damage. Such a "worst case" approach is only necessary if the storm reserve and associated accrual are the only means by which a utility is able to obtain coverage for damages from storms. (Tr. 2322-2323). The Commission has already demonstrated that this is clearly not the case.

It is FIPUG's position that the storm accrual should cease at this time, to mitigate the requested rate increase. Ceasing the accrual will not harm the ratepayers. Over time, the level of the reserve may decline. However, absent a direct strike in the most populated portion of PEF's service territory, or the once in every 33-year storm occurrence causing over $130 million in damage, the current reserve balance is sufficient to cover the EAL for the next eight years. If losses remain at the levels experienced over the 2006-2008 period, the current reserve is more than capable of supporting storm recovery for 30 years, without any further ratepayer contributions. (Tr. 2324).

Going forward, the Commission should require that in any subsequent study presented, alternative levels of storm damage are considered. Any subsequent study should look at the reserve performance taking into account only Category 1 storms and also potentially Category 2 storms. This approach gives recognition to the framework for addressing storm restoration costs – that being that the accrual and reserve balance is designed to cover most but not the most destructive storms. (Tr. 2324-2325).

ISSUE 35: Should unamortized rate case expense be included in Working Capital?

POSITION: *No.*

ISSUE 36: Has PEF appropriately reflected the impact of SFAS 143 (Asset Retirement Obligations) in its proposed working capital calculation?

POSITION: *No. PEF has not demonstrated that it has reflected the impact of SFAS 143 in a revenue neutral manner as required by Rule 25-14.014, F.A.C. Absent any demonstration that PEF has complied with the rule, the Commission should require PEF to record an appropriate reduction to rate base to offset the increase in working capital caused by the ARO adjustment.*

ISSUE 37: Is PEF's requested level of Working Capital Allowance in the amount of ($9,041,000) for the projected test year appropriate?

POSITION: * No. Working capital allowance should be increased $26,190,221 after adjusting for removing unamortized rate case expense and excess storm damage reserve amounts.*

ISSUE 38: Is PEF's requested level of Rate Base in the amount of $6,238,617,000 for the 2010 projected test year appropriate?

POSITION: *No. The adjustments suggested by Intervenors should be made.*

COST OF CAPITAL

ISSUE 39: What is the appropriate amount of accumulated deferred taxes to include in the capital structure for the projected test year?

POSITION: * The appropriate amount of accumulated deferred taxes to include in the capital structure for the projected test year is $373,161,000.*

ISSUE 40: What is the appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure for the projected test year?

POSITIONS: *The appropriate amount of the unamortized investment tax credit is $4,991,000. The appropriate cost rate is 7.84%.*

ISSUE 41: Should PEF's requested pro forma adjustment to equity to offset off-balance sheet purchased power obligations be approved?

POSITION: *No. PEF should not be permitted to impute debt for purchased power agreements. Recovery for such contracts is under the purview of this Commission and once such contracts are approved, PEF is entitled to full and direct recovery of all such costs and has no risk of disallowance. Thus, they should not be treated as imputed debt.*

DISCUSSION

PEF seeks to impute $711 million of debt related to its purchase power agreements (PPAs). (Tr. 1259). This translates into an annual revenue requirement, which ratepayers must bear, of $24 million. (Tr. 1701). This "imputation of debt" is not an equity investment or an investment in plant or assets. (Tr. 1259, 1707). It is simply an "adjustment" which PEF wants to make. (Tr. 1260).

PEF says it must make this adjustment because the financial community commonly takes into account obligations associated with PPAs. Since PEF has long-term PPAs, it is obligated to make certain fixed payments, which, it asserts, the rating agencies regard as equivalent to long-term debt. (Tr. 1245).

The Commission has very recently addressed precisely this issue in the Tampa Electric rate case. The Commission denied Tampa Electric's request for the same PPA adjustment PEF seeks:

> The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. 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 without having actually made the equity investment.

The Commission went on to find:

> Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:
>
> 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 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.

Further, in rejecting Tampa Electric's request, the Commission held:

> With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended.[20]

Having just rejected the very same request from Tampa Electric, PEF's request should similarly be denied.

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[20] In re Tampa Electric, Docket No. 080317-EI, *Order No. PSC-09-0283-FOF-EI* at 35-36.

In addition, the substance of PEF's argument is without merit. PEF's imputed debt adjustment reflects the methodology outlined by S&P. It is noteworthy that another ratings agency, Moody's, does not make a similar adjustment. It is also critical to recognize that PEF did not produce a single witness from S&P, (Tr. 1263), who could explain how a 25% adjustment was arrived at rather than a 50% adjustment or a 5% adjustment. The Commission should not make decisions without having the opportunity to directly speak to the parties responsible for the recommendations under consideration.

While PEF used the general 25% risk factor S&P uses, it does not accurately reflect the risk (or non risk) associated with the recovery of PPA costs in Florida. As this Commission is well aware, purchased power costs are subject to dollar-for-dollar recovery through the adjustment clauses. This includes a true-up procedure that establishes a forward-looking charge, which is then reconciled based on actually incurred costs, with interest. (Tr. 3208). PEF Treasurer Sullivan acknowledged that he was unaware of *any circumstance* in which a utility had been unable to recover the full amount of all PPA payments. (Tr. 1263). Witness Sullivan further acknowledged that there is a very low risk in Florida that PEF will not recover its PPA costs. (Tr. 1263).

S&P itself recognizes the relationship between risk and the recovery mechanism. S&P states:

> The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors.[21]

[21] Exhibit No. 94, Standard & Poor's *Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements* at 3.

But S&P does not provide an objective standard for determining the appropriate risk factor. Dollar-for-dollar recovery of PPA costs is a very strong mechanism with no practical risk. PEF's PPAs have been previously approved for recovery. In fact, the above discussion from S&P, in conjunction with the policies and previous findings, in Florida strongly suggest that the obligations under Commission-approved PPAs are risk free, so long as the utility properly manages the contracts. (Tr. 3209).

In contrast to S&P, Moody's specifically recognizes that the risk of PPAs is directly related to the applicable cost recovery mechanism as well as market dynamics:

> Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.[22]

Thus, it is clear that Moody's does not regard PPAs as inherently risky and therefore, it imputes no debt for these contracts where recovery is guaranteed.

Further, Moody's recognizes that PPAs can be less risky for a utility:

> Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.[23]

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[22] Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005 at 9.
[23] *Id.*

Based on the above statements by Moody's, it seems unlikely that debt will be imputed to PEF based on the cost recovery mechanisms applicable to purchased power capacity costs. Imputed debt should not be included in assessing the reasonableness of PEF's capital structure.

ISSUE 42: What is the appropriate equity ratio that should be used for PEF for purposes of setting rates in this proceeding?

POSITION: *The appropriate equity ratio for PEF is 50.3%. This is comparable to other A-rated electric utilities. This capital structure reduces PEF's revenue request by $33 million.*

ISSUE 44: What is the appropriate capital structure for the projected test year?

POSITION: * See Issue 41 regarding disallowance of an adjustment for purchased power agreements and Issue 42 as to the appropriate equity ratio. FIPUG agrees with OPC as to the other components of capital structure.*

DISCUSSION

These issues relate to what impact, if any, PEF's PPAs have on PEF's capital structure. PEF proposes an adjustment to its capital structure of $711.3 million to increase common equity. (Tr. 3213). This equates to an annual (and unnecessary) revenue requirement of $32.9 million. (Tr. 3215).

PEF's imputation position results in an increase in its common equity ratio to 53.9%. As discussed below, the cost of common equity is greater than the cost of debt, so the adjustment causes an increase to PEF's proposed rate of return. The Commission should eliminate the PPA adjustment in determining PEF's capital structure. This would reduce PEF's common equity ratio to 50.3%.

A comparison of common equity ratios for the 2006 to 2009 (1st quarter) time frame shows the average common equity ratios for all electric utilities range from 46.1% to 47.6% (Exhibit No. 200). On a comparable basis, the adjusted 2010 test year common equity ratio of

50.3% would be well above the average. Thus, PEF's suggestion would result in a common equity ratio 345 basis points higher than the electric utility average. (Tr. 3213-3214).

Such a high equity range would be detrimental to ratepayers. Common equity is more expensive than debt. In this instance, PEF is asking for a common equity return that is over 600 basis points higher than its embedded cost of long-term debt. A utility having too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the higher and the rates all PEF ratepayers will bear. (Tr. 3214).

Throughout this case, the Commission heard utility witnesses opine that they must have a higher bond rating to access capital markets. FIPUG disagrees with this view and addresses it elsewhere in this brief. However, as to capital structure, a 50% common equity ratio is sufficient to maintain PEF's current bond rating. PEF is currently rated "A3" by Moody's and "A-" by Fitches and "BBB+" by S&P. The chart below provides a comparison of the common equity ratios for other A-rated electric utilities.

Year	**All Electric Utilities**	**A-Rated Electric Utilities**
2006	47.6%	50.9%
2007	47.3%	51.0%
2008	46.4%	49.5%
2009 (Q1)	46.1%	49.5%
Average	46.9%	50.2%

Thus, PEF's 50.3% projected test year common equity (without including off balance sheet obligations) is consistent with comparable A-rated electric utilities. (Tr. 3214-3215).

PEF's adjusted common equity ratio of 50.3% (excluding the PPA adjustment) should be the basis for setting its cost of capital in this proceeding. This translates into a 46.93% regulatory common equity ratio. Reducing the regulatory common equity ratio to 46.93% lowers PEF's requested 2010 base revenue increase by about $32.9 million. (Tr. 3215; Exhibit No.201).

ISSUE 43: Have rate base and capital structure been reconciled appropriately?

POSITION: *No position.*

ISSUE 45: What is the appropriate cost rate for short-term debt for the projected test year?

POSITION: *The appropriate cost rate for short-term debt for the projected test year is 3.06%.*

ISSUE 46: What is the appropriate cost rate for long-term debt for the projected test year?

POSITION: *The appropriate cost rate for long-term debt for the projected test year is 6.05%.*

ISSUE 47: What is the appropriate return on equity (ROE) for the projected test year?

POSITION: *The appropriate ROE should be no higher than 9.75%.*

DISCUSSION

According to testimony and Exhibit No. 264, even if the Commission were to reduce PEF's requested ROE by 1 full percentage point, or 100 basis points, and award it an ROE of 11.54%, the Commission's decision would still provide PEF with the highest authorized ROE in the country for 2009. (Tr. 4221). This Commission should either award PEF the ROE recommended by OPC's expert witness, Dr. Woolridge, of 9.75%, or award PEF the average ROE awarded in 2009, 10.51%. Such a decision is well supported by competent substantial evidence and will not impair PEF's ability to access capital, particularly when one considers that many of the companies listed on Exhibit No. 264 which have received an ROE of 10.5% have bond ratings lower than PEF. CEO Dolan was unaware of any company that had a pending or decided rate case in 2009 that has asked for a greater return than PEF seeks in this case. (Tr. 295).[24]

Economic theory suggests that investors will invest in a company with less risk if they can earn a return at the same level or a slightly higher level as compared to a similar company with greater risk. (Tr. 4203). PEF is rated higher, *i.e.* it has less risk, than TECO according to the rating agencies. (Exhibit No. 294; Tr. 4223). This Commission determined that an ROE of 11.25% was adequate to allow TECO to attract capital given its risk. (Tr. 4221). Since PEF has less risk than TECO, PEF should be awarded an ROE lower than TECO's 11.25%, consistent with economic theory. (Tr. 4223).

PEF's reported return on equity for 2008, found in its Annual Report, was 9.59%. (Tr. 4220-4221). Despite reporting a ROE of 9.59% in its 2008 Annual Report, PEF was able to raise $545 million in equity in the first quarter of 2009, a fact which undercuts PEF's contention that it may have difficulty raising capital unless this Commission grants PEF its requested ROE of 12.54%. (Tr. 4189). The market for capital is a national market. (Tr. 4202). Commissions addressing an appropriate ROE in 2009 for regulated utilities to access the national capital market have approved an average ROE of 10.51%, with many of the companies who received an ROE of 10.5% being rated lower than PEF. (Exhibit Nos. 264; 294).

Put simply, PEF's ROE request is inflated. It does not need a ROE of 12.54%[25] to access capital; an ROE of 10.51% would be more than adequate. CEO Dolan admitted that at a lower ROE, such as 10.51%, the company would be able to meet its statutory obligation to serve. (Tr. 2657).

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[24] It is also interesting to note that while PEF seeks a 12.54% ROE, it is satisfied if its pension fund investments earn 8.75%. (Tr. 1827).

[25] PEF witness Toomey astonishingly testified that an ROE below 12.54% would be a "low" ROE. (Tr. 1788).

Each 100 basis points for PEF represents approximately $50 million of expense the ratepayers must bear. By reducing PEF's 12.54% ROE request to 10.54%, for example, the ratepayers would save $100 million (Tr. 187, 1790) – or close to 25% of PEF's requested $1/2 billion request.

ISSUE 48: What is the appropriate weighted average cost of capital including the proper components, amounts, and cost rates associated with the projected capital structure?

POSITION: *The appropriate weighted average cost of capital including the proper components, amounts and costs rates associated with the projected capital structure is 7.48%.*

NET OPERATING INCOME

ISSUE 49: Is PEF's projected level of total operating revenues in the amount of $1,517,918,000 for the 2010 projected test year appropriate?

POSITION: *Projected operating revenues should be adjusted by $8,646,274.*

ISSUE 50: What are the appropriate adjustments to reflect the base rate increase for the Bartow Repowering Project authorized in Order No. PSC-09-0415-PAA-EI?

POSITION: *No position.*

ISSUE 56: Has PEF made the appropriate adjustments to remove Aviation cost for the test year?

POSITION: *No position.*

ISSUE 57: Should an adjustment be made to advertising expenses?

POSITION: *No position.*

ISSUE 59: Is PEF's proposed allowance of $2,412,100 for directors and officers liability insurance appropriate?

POSITION: *No, this amount should be disallowed. Ratepayers should not be required to fund this expense which directly benefits only PEF's shareholders.*

ISSUE 60: Is PEF's proposed allowance of $3,669,000 for 2010 injuries and damages expense appropriate?

POSITION: *No. This amount should be disallowed because it is not supported in PEF's filing.*

ISSUE 61: Is PEF's proposed allowance of $23,228,000 for 2010 A&G office supplies and expenses appropriate?

POSITION: *No. $2,331,755 of A&G Office Supplies and Expense should be disallowed as a result of the failure to explain or justify those expenses in the 2001 budget.*

ISSUE 62: Should an adjustment be made to PEF's proposed 2010 allowance for O&M expense to reflect productivity improvements, if any?

POSITION: *Yes. The Commission should recognize PEF's incentive to implement post rate case award efficiencies beyond those reflected in its filing. PEF's strategic plan sets as a goal achievement of annual productivity gains of 3-5%. The Commission should utilize the more conservative target of 3% and reduce projected O&M expense by $13.034 million.*

ISSUE 63: Should an adjustment be made to PEF's requested level of salaries and employee benefits for the 2010 projected test year?

POSITION: *Yes. See Issues 64-66.*

ISSUE 64: Are PEF's proposed increases to average salaries for 2010 appropriate?

POSITIONS: * No; in these difficult economic times, PEF should be required to tighten its belt just as many citizens, county governments and school boards must do. Employee increases are inappropriate.*

ISSUE 65: Are PEF's proposed increases in employee positions for 2010 appropriate?

POSITIONS: *No; PEF should be required to freeze employee hiring in order to hold down costs, just as many citizens, county governments and school boards must do.*

ISSUE 66: Should the proposed 2010 allowance for incentive compensation be adjusted?

POSITION: *Yes. At a minimum, the Commission should disallow $18.25 million of incentive compensation. Such additional awards should not be permitted in light of the difficult economic climate.*

DISCUSSION

These issues relate to PEF's request for salary increases across the board for all employees as well as its request that ratepayers pick up the entire tab for its management incentive plans. The Commission heard much testimony and is well aware of the drastic economic hardship that has befallen Florida. Florida has very high unemployment rates and high foreclosure rates. Many Floridians and local governments have been forced to tighten their belts, freeze salaries and lay off employees in light of the economic downturn. Floridians expect similar belt tightening from PEF, but PEF has continued in "business as usual" mode.

Across the Board Salary Increase

PEF witness DesChamps,[26] Director of Compensation and Benefits for PEF, acknowledged in his testimony that he was familiar with the hard economic times in Florida, including the unemployment and foreclosure rates and the high unemployment rate. (Tr. 834). Despite these harsh realities, PEF has included a 3.75 percent[27] increase across the board in compensation in its test year expenses. (Tr. 835). Given the magnitude of the increase PEF has requested, holding the line on employee compensation increases is reasonable to reduce the burden on ratepayers and to reflect the current harsh economic realities. The Commission should freeze all PEF compensation.

Incentive Compensation

Of particular concern are the increases in incentive compensation which PEF seeks to have funded 100% by ratepayers.[28] PEF has proposed to include a total of $33.9 million of incentive compensation in labor costs as a test year expense. (MFR Schedule C-35). PEF's CEO, Mr. Dolan, while recognizing the difficult economic times Floridians face (Tr. 219),

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[26] The majority of witness' DesChamps "opinions" were based on inadmissible hearsay and lack of authentication of the documents he relied upon. PEF had no witness at the hearing who could testify about the studies and documents upon which witness DesChamps relied nor had witness DesChamps even reviewed the data underlying the documents. FIPUG objected to such information at the hearing, but its objections were overruled. FIPUG maintains its objection.
[27] This is to be compared with Hewitt Associates August 2009 study showing that compensation budgets increased by only 1.8%. (Tr. 3283).
[28] Adding insult to injury is the fact that PEF is over the Commission benchmark for long term compensation by over $8 million. (Tr. 838).

unequivocally rejected the suggestion that executive compensation increases be frozen and noted that such increases were "a fundamental part of our case." (Tr. 174). Witness DesChamps testified that PEF is not even willing to consider freezing executive compensation. (Tr. 838).

Incentive compensation is the additional compensation paid to employees to encourage certain behavior and/or results. It is paid as a reward for the individual and business group achieving certain goals and objectives. Payment is discretionary and contingent[29] on the employee/business unit achieving the goals. (Tr. 2309).

Each of PEF's compensation plans use earnings per share of the parent company as one of the metrics used to determine compensation. (Tr. 3301). The long-term incentive plan also uses relative shareholder return (how company shareholder returns compare to other companies) and earnings growth to evaluate compensation. (Tr. 3302). Because these expenses do not benefit ratepayers, they should not be charged to them. (Tr. 2309).

Incentive compensation should be carefully scrutinized because, despite the fact that PEF expects the ratepayers, as opposed to the shareholders, to fund all incentive compensation, not all incentive compensation benefits ratepayers. Incentive compensation that is targeted to achieve certain financial goals is only for the benefit of shareholders and provides little if any benefit to ratepayers. Therefore, FIPUG recommends the following disallowances related to incentive compensation:

- $2.6 million of incentive compensation budgeted for executives and senior management (executives).
- $15.6 million (or 50%) of the incentive compensation applicable to other management and non-management.

[29] Despite the fact that PEF has included the entire amount it seeks for incentive compensation in the test year, Witness DesChamps admitted that the plan could be suspended or terminated at any time. (Tr. 822-823).

This would result in an overall reduction in incentive compensation of $18.25 million from the level shown on Schedule MFR C-35.[30] (Exhibit No. 184).

PEF has several compensation plans: (1) the Executive Incentive Plan (EIP), which applies to Executives, (2) the Senior Management Performance Sub-Share Plan, which applies to senior managers, (3) the Management Incentive Compensation Plan (MICP), which applies to other managers, and (4) the Employee Cash Incentive Plan (ECIP), which applies to all other employees. (Tr. 2310-2311).

Under the EIP, the incentive payment is at the discretion of the Organization and Operations Committee of the Board of Directors of Progress (Committee), with the potential award pool to be funded from up to 1% of the operating income of Progress, the parent of PEF. (Tr. 2311).

Under the Senior Management Performance Sub-Share Plan, senior managers may receive stock awards. The level of the stock award payout is tied to a combination of the total shareholder return and the rate of growth in the ongoing earnings per share of Progress during the performance period. Both of these measures are based on the financial results of Progress. (Tr. 2311).

Under the MICP, payout is based in part on the earnings per share (EPS) of Progress and upon "legal entity" EBITDA (this measure looks at Earnings before Interest, Taxes, Depreciation and Amortization the "legal entity," the operating company, such as PEF or Progress Carolina, as applicable). (Tr. 2311).

Finally, under the ECIP, payout is based upon two equally weighted components. One component is based upon an EPS target for Progress, with an additional percentage allowable to

[30] Similar to the position of OPC witness Schultz (Tr. 3280), FIPUG's position is that these amounts should be disallowed for *ratemaking purposes*. To the extent shareholders believe these costs are justified, they should fund them.

all employees at the CEO's discretion. The other half of the payout is tied to business unit goals and the individual's performance in helping the business unit achieve the goals. Individuals may receive up to 150% of their targeted award, depending upon performance in both categories. Further, to the extent the minimum EPS goal for Progress is not achieved, not only would the portion contingent on Progress achieving its EPS goal not be paid, but the overall business unit portion of the award, referred to as the Operational Excellence portion of the award, may also be reduced by up to 15% . (Tr. 2311-2312).

PEF testified that its incentive compensation plan is intended to "align the interests of customers, shareholders, employees, and management." (Tr. at 812). However, when pressed regarding how an increase in earnings per share for a stockholder might benefit the ratepayers, witness DesChamps answered "I would say I don't know...." (Tr. 842). Witness DesChamps further admitted that an increase in share price does not convey a customer satisfaction benefit. (Tr. 842). Finally, the following exchanged occurred which makes it clear that PEF cannot tie appreciation in the price of the stock of its parent company to the ratepayers' interests:

> Q. [Ms. Kaufman] But when I get a bigger dividend or, you know,
> sell my stock at a profit because it has appreciated, is
> it your testimony that that's a benefit to the ratepayers?
>
> A. [Mr. DesChamps] I don't know.

(Tr. 843). Clearly, the connection has not been established nor could it be as ratepayers do not benefit from compensation awards based on parent company earnings.

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. That compensation is predicated upon the earnings of the parent company, Progress, and not tied to the results of the operating company, PEF. Therefore, none of these costs should be borne by ratepayers. This results in a disallowance of $2.6 million. (Tr. 2314).

Fifty percent (50%) of the total incentive compensation for management and non-management employees in the amount of $15.6 million be removed from labor expense. Incentive compensation under the MICP is based on a combination of the EPS of Progress and upon "legal entity" (which appears to be a reference to the operating company for which the employee works) EBITDA. Each of these items benefits only shareholders. Similarly, 50% of any award under the ECIP is based upon Progress achieving a minimum EPS level. Absent Progress achieving that minimum level, a payout under the ECIP would be 50% or more lower than the target maximum award level. To the extent that the reward is for enhancing shareholder returns, the payment is much more in the nature of a profit sharing between shareholders and management. To the extent that employees are being paid for enhancing value to shareholders, it is shareholders that should bear the overall responsibility of such costs. (Tr. 2314-2315).

This Commission has recently excluded compensation for senior officers related to parent company earnings. In the recent Tampa Electric rate case, the Commission disallowed certain executive compensation:

> We also find, however, that the incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent Company TECO Energy.[31]

[31] In re: Tampa Electric Company, Docket No. 080317-EI, *Order No. PSC-09-0283-FOF-EI* at 58. PEF witness DesChamps insisted that the Tampa Electric disallowance was somehow related to the diversified activities of Tampa Electric's parent company. However, he is reading something into the decision that is not there. The Commission found that compensation should be <u>directly</u> tied to the regulated utility – this is not the case with PEF nor was it the case with Tampa Electric.

In the case of PEF, a large portion of incentive compensation for all levels of employment is tied directly to the earnings of the parent company, Progress, and not the results of PEF or upon measures that benefit ratepayers of PEF. (Tr. 2316).

ISSUE 67: Should the Company's proposed 2010 allowance for employee benefit expense be adjusted?

POSITION: *Yes. Employee benefits expense should be reduced by $9,376, 809 to account for an unexplained discrepancy between the MFRs and the revised MFRs. Additionally, an adjustment needs to be made to be consistent with the adjustment in the level of employee due to vacant positions.*

ISSUE 68: Should an adjustment be made to the accrual for property damage for the 2010 projected test year?

POSITION: *Yes. The accrual for storm damage should be eliminated. See discussion in Issue 33.*

ISSUE 69: Should an adjustment be made to PEF's 2010 generation O&M expense?

POSITION: *Yes. PEF's steam and other generation O&M expense is overstated. PEF projects a 36% increase in expenses compared to its budgeted 2009 numbers. It projects a 57% increase in comparison to its four-year average (2006-2009) expenses. This dramatic increase is a result of PEF moving a CR3 outage from a period beyond the 2010 test year, additional planned outages, and a "contingency" expense. A $15 million reduction should be made to generation O&M to address these excessive amounts.*

ISSUE 70: Should an adjustment be made to PEF's 2010 transmission O&M expense?

POSITION: * Yes. PEF's transmission expense should be reduced by $3.75 million. PEF has overstated the amount of this expense by including storm hardening activities, like vegetation management and tree trimming, which have been required by the Commission since 2006.*

ISSUE 71: Should an adjustment be made to PEF's 2010 distribution O&M expense?

POSITION: *Yes. PEF's distribution expense should reduced by $13.9 million. PEF has overstated the amount of this expense by including storm hardening activities, like vegetation management and tree trimming, which have been required by the Commission since 2006.*

DISCUSSION[32]

The three issues above deal with PEF's overstated O&M expenses. Because PEF has used a projected test year in this case, to the extent that overstated expenses are included, it will allow PEF to lock in such expenses until its next rate case, even if such amounts are not needed to provide service to ratepayers. In order to make the test year more representative, the following reductions should be made to O&M expenses:

- $3.75 million for FERC Account No. 571 – Transmission Overhead Lines Maintenance;
- $13.9 million for FERC Account 593 – Distribution Overhead Line Maintenance;
- $15 million adjustment to Steam and Other Generation Maintenance expenses.

(Tr. 2300-2301).

Transmission and Distribution Overhead Lines

FERC accounts 571 and 593 record expenses associated with the maintenance of overhead transmission lines and the maintenance of overhead distribution lines, respectively. Included within the type of expenses to be recorded in the two accounts are maintenance costs associated with tree trimming and vegetation removal and management. (Tr. 2301).

The amounts PEF has recorded in these accounts have increased substantially for the test year. Account 593 costs remained relatively constant from 2006 through 2008, up to and including the budgeted 2009 expense. However, in the test year, expenses rise from about $32 million in 2009 to over $45 million. (Tr. 2303). Account 593 expenses increased by $3.8 million (47%) from 2009 to 2010, and are $4.5 million (62%) higher than the 2006-2009 average

[32] FIPUG witness Marz presented testimony on each of these issues. His testimony was accepted by the Commission, entered into evidence, and he was challenged or examined by PEF. (Tr. 2922).

expenses. (Tr. 2303). PEF witness Joyner, Vice President of Distribution, testified that there was an acceleration of expenditures in 2010, the test year. (Tr. 722).

PEF attempts to attribute these large increases to the additional cost of vegetation management related to Commission initiatives as to hurricane preparation and storm hardening. (Tr.2300-2301). However, these programs are not new undertakings occurring for the first time in the test year. In fact, the Commission established a ten-step program to encourage vegetation management in *2006*, following a series of tropical storms and hurricanes that struck Florida during the 2004 - 2005 time frame. In 2006, the Commission "issued Order No. PSC-06-0351-PAA-EI, requiring the investor-owned electric utilities to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives on or before June 1, 2006."[33]

By 2006, PEF had already undertaken a review of its vegetation management policy and implemented an integrated vegetation management (IVM) program. The IVM program was approved by the Commission in late 2006.[34] Separately, in 2007, the Commission approved PEF's storm hardening plan.[35] Thus, the overall increase in costs associated with the IVM program should already be reflected in actual tree trimming and vegetation management expenses in both Accounts 571 and 593 as far back as 2006.

Given that the IVM program was approved and implemented in 2006, a substantial cost increase should not only now be reflected in the test year expenses. The projected increase in test year costs cannot be explained by the IVM and storm hardening programs. Therefore 2009 levels should be used for the test year expenses for Accounts 571 and 593. This would reduce O&M expenses by $3.75 million for Account 571 and $13.9 million for Account 593. (Tr. 2304).

[33] *Order No. PSC-06-0947-PAA-EI*, Docket No. 060198-EI, November 13, 2006.
[34] *Id.*
[35] *Order No. PSC-07-1021-FOF-EI*, Docket No. 070288-EI, December 28, 2007.

Production Expenses

PEF's MFR C-6 shows that PEF projects its O&M expenses in the test year for Steam and Other Production Maintenance to be $111.1 million. These expenses are overstated. Comparing the 2010 test year expense to the 2009 budgeted numbers, PEF is projecting a $29.3 million or a 36% increase. The corresponding four-year average (2006-2009) increase is $40.6 million or 57% as shown on Exhibit No. 182. (Tr. 2305).

PEF's explanation for these increased expenses lacks merit. PEF witness Sorrick identifies an accelerated outage at Crystal River 4 (CR4) for major boiler and turbine maintenance that will cost $9.3 million. This outage accounts for 28% of the projected increase in Steam Generation Maintenance expense. (Tr. 2305-2306). However, this outage was not originally scheduled for the test year and was moved into 2010 from a later time period. (Tr. 395).

Further, this is not an annual outage but occurs only once every nine years. As PEF acknowledged in an interrogatory response:

> The type of work that will be performed during the boiler outage includes scaffolding the boiler, inspecting the boiler and repairing the items identified during the inspection. The type of work that will be performed during the turbine outage, which is typically performed every 9 years, includes the inspection and repairs of the internal and external steam components. Therefore, these outages have been scheduled to be performed during the spring of 2010 at the same time the FGD and SCRs will be installed. PEF would normally schedule these maintenance outages in the normal course of its operations but PEF decided to accelerate them to capture synergies in outage costs with the outage for the FGD and SCR work as well as minimize lost generation instead of taking an additional outage.

(Tr. 2306). It is inappropriate to reflect the full cost of this outage in the test year. Even assuming that the outage should be recognized, the full cost should not be included in setting rates in this case. Doing so assumes that PEF would incur the full outage cost annually instead of once every nine years. Thus, PEF would over-recover its costs. At most, only 11.1% (one-ninth) of the CR4 outage costs should be recognized for ratemaking purposes. (Tr. 2306).

In addition, there are further questionable expenses included in the test year. There are additional planned outages at certain of the combined cycle and combustion turbine plants increasing overall O&M costs. There are also increased costs at the Hines Power Block and overhauls and increased staffing for the repowered Bartow facility. Finally, there is also a $5.3 million increase for emerging equipment issues and other repairs. (Tr. 2307).

Finally, PEF has included a $5.3 million dollar expense for "emerging equipment" costs and other items. This amount appears to be a contingency put in to preserve PEF's options. PEF indicated in discovery that "This funding would be used for forced outage repairs or to take advantage of opportunities to enhance the fleet." It appears the amount is a "contingency expense" – something placed in the budget in case expense estimates are too low. (Tr. 2306). This is inappropriate.

An overall $15 million reduction should be made to the combined Steam and Other Generation maintenance expense. The adjustment represents an approximate 50% reduction in PEF's projected increase in these expenses from 2010 over 2009. Even at the lower recommended level, it would still represent a 17% increase over PEF's 2009 budget and a 36% increase over the four- year average (2006-2010) expense. (Exhibit No. 183).

ISSUE 73: What is the appropriate amount and amortization period for PEF's rate case expense for the 2010 projected test year?

POSITION: *Rate case expense should be amortized over 4 years. Rate case expense should be reduced by $989,618 and the amount included in rate base should be reduced at least $969,531.*

DISCUSSION

PEF recommends that its rate case expense be amortized over a period of two years. (Tr. 1796). PEF further contends that its recommendation is based on "long standing Commission practice." (Tr. 1663). In providing that testimony, PEF relied on a Tampa Electric order from 1982. However, this statement actually is in direct contrast to long-standing Commission practice regarding rate case amortization.

In the recent Tampa Electric rate case order,[36] the Commission held: "the amortization period shall be increased from three to four years, which is consistent with several of our recent rate cases." Witness Toomey admitted that the four-year amortization was the more recent Commission practice. (Tr. 1800).

ISSUE 75: What adjustments, if any, should be made to the 2010 projected test year depreciation expense to reflect revised depreciation rates, capital recovery schedules, and amortization schedules resulting from PEF's depreciation study?

POSITION: * The adjustments recommended by Intervenors should be made. See discussion contained in Issues 8 - 13.*

ISSUE 76: What is the appropriate amount of depreciation and fossil dismantlement expense for the 2010 projected test year?

POSITION: * The adjustments recommended by Intervenors should be made. See discussion contained in Issues 8 - 13, 17, 19 - 20.*

ISSUE 80: Should an adjustment be made to taxes other than income taxes for the 2010 projected test year?

POSITION: *No position.*

ISSUE 81: Is it appropriate to make a parent debt adjustment as per Rule 25-14.004, Florida Administrative Code?

POSITION: *Yes.*

ISSUE 82: Should an adjustment be made to Income Tax expense for the 2010 projected test year?

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[36] *Order No. PSC-09-0283-FOF-EI* at 65.

POSITION: * Any adjustment is a fall out of other adjustments.*

ISSUE 83: Is PEF's requested level of Operating Expenses in the amount of $1,249,372,000 for the 2010 projected test year appropriate?

POSITION: *No. The adjustments recommended by Intervenors should be made.*

ISSUE 84: Is PEF's projected net operating income in the amount of $268,546,000 for the 2010 projected test year appropriate?

POSITION: *No. The adjustments recommended by Intervenors should be made.*

ISSUE 85: Has PEF appropriately accounted for affiliated transactions? If not, what adjustment, if any, should be made?

POSITION: *No. PEF has failed to appropriately recognize the value of the use of its name by its non regulated operations.*

DISCUSSION

PEF has a numerous unregulated operations that market non regulated services to its captive customers. (Tr. 2250). These unregulated operations receive substantial benefits due to their association with PEF, the regulated utility, apparently at no cost. As witness Toomey testified, the unregulated entities have an advantage over competitors in marketing their services. (Tr. 1808).

Witness Dismukes described some of these benefits:

> These benefits include the use of Progress Energy's name, logo, reputation, goodwill, and corporate image; being associated with a large, financially strong, well-entrenched electric company; use of Progress Energy's personnel; and use of Progress Energy's facilities. All of these benefits were developed as a result of the regulated operations. However, the nonregulated operations obtain these significant intangible benefits of being associated with the regulated utility operations at no cost.

(Tr. 2260). To recognize these unaccounted for benefits, FIPUG supports the recommendation of OPC that PEF be required to treat the revenues, expenses and investment from these operations above the line for rate setting purposes. Alternatively, the Commission should assess a royalty fee for the intangible benefits the non regulated operations receive as a result of their association with the regulated utility.

REVENUE REQUIREMENTS

ISSUE 87: Is PEF's requested annual operating revenue increase of $499,997,000 for the 2010 projected test year appropriate?

POSITION: * No. Required annual operating revenues for the 2010 projected test year are ($35,038,000). PEF's retail rates should be reduced to reflect this.*

COST OF SERVICE AND RATE DESIGN

ISSUE 88: Has PEF correctly calculated revenues at current rates for the projected test year?

POSITION: *No position.*[37]

ISSUE 89: Is PEF's proposed separation of costs and revenues between the wholesale and retail jurisdictions appropriate?

POSITION: *No position.*[38]

ISSUE 90: What is the appropriate Cost of Service Methodology to be used to allocate base rate and cost recovery costs to the rate classes?

POSITION: * The Commission should continue to use the 12CP and 1/13th AD cost of service methodology. It should not adopt the cost of service methodology PEF proposes, 12CP and 50% AD, because this methodology fails to follow cost causation principles. If the Commission does decide to replace the 12CP and 1/13th AD method, it should adopt the Average and Excess (A&E) method described in witness Pollock's testimony. The summer/winter coincident peak method described by witness Pollock should be used to allocate transmission plant costs.*

DISCUSSION

A class cost of service study is used to determine each class' responsibility for the revenue requirements the Commission ultimately determines. A class cost-of-service study

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[37] FIPUG's position is based on PEF's withdrawal of its revised sales forecast and the Commission's ruling that it will not be considered in this case. (Tr. 13).

[38] FIPUG's position is based on PEF's withdrawal of its revised sales forecast, revised jurisdictional study and the Commission's ruling that it will not be considered in this case. (Tr. 13).

separates the utility's total costs into portions incurred on behalf of the various customer groups. (Tr. 3162). The polestar of an appropriate cost of service study is to use the methodology that most accurately reflects cost causation. Cost causation means allocating production and transmission plant costs to customer classes in a manner that reflects how each class causes PEF to incur them. (Tr. 3163). Witnesses Pollock and Slusser agree that cost causation should be used to select the right methodology. (Tr. 3163; 1523).

PEF proposes to use the 12CP-50% AD methodology. The 12CP-50% AD method allocates costs partially on a 12CP demand basis and partially on an average demand, or energy, basis. Thus, 12CP-50% AD assumes that production plant-related costs are caused by year-round coincident peaks and average demand. (Tr. 3165).

First, it should be noted that PEF witness Slusser[39] admitted that the 12CP-50% AD is the same methodology as the Equivalent Peaker method. (Tr. 1530). The Commission squarely rejected this method in the Gulf Power rate case[40] and held:

> The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of plant costs to hours past the break-even point. The near peak method includes too narrow a spread of peak hours in our view.

Second, the 12CP-50% AD method is highly flawed and does not reflect cost causation. It is undisputed that PEF has clear seasonal load characteristics. (Tr. 3166). PEF experiences its maximum annual demand for electricity in either the summer or winter months. (Exhibit No. 189). The peak demands in the other months are typically well below PEF's summer and winter peak demands. (Exhibit No. 189). Witness Pollock's analyses demonstrate that the 12CP method does not reflect cost-causation in light of PEF's load and supply characteristics.

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[39] During witness Slusser's entire career he has worked only for PEF (or its predecessor) with the exception of a project for Tampa Electric. (Tr. 1522).
[40] In re: Petition of Gulf Power Company for an increase in Its Rates and Charges, Docket No. 891345-EI, *Order No. 23573.*

Further, as PEF witness Slusser admitted, the reason that PEF must add capacity is due to the peak load of the residential class – PEF's largest class. (Tr. 1604-1605, 1614). PEF does not build capacity to serve the demand of the interruptible class. (Tr. 1592).

In addition, the methodology PEF recommends is not related to cost causation. Rather, PEF is proposing to replace the principle of cost-causation with a "costs follow the benefits" standard. PEF argues that because there are fuel benefits from its production plant choices, more production plant should be allocated on an energy basis.

However, PEF has applied this standard only to the allocation of production plant costs. It fails to apply the same standard to the allocation of variable costs (of which fuel is the primary component). For example, PEF does not propose to change how customers are charged for fuel, which is currently on an equal cents per kWh basis (adjusted for losses). If certain customer classes benefit more from the lower fuel costs of base load and intermediate plants, it follows that they should also pay below-average fuel costs, and vice versa. By failing to apply this theory consistently to both plant and operating costs the class cost-of-service study is fundamentally flawed and discriminatory. (Tr. 3167-3168).

PEF has also erroneously assumed that all variable costs are energy-related. This assumption is flawed because it overlooks the fact that PEF also incurs higher fuel costs to save plant costs and to maintain system reliability. If it is proper to classify 50% of plant-related costs to energy because certain customer classes may realize greater cost benefits than others, it is equally proper to classify some operating costs to demand because they provide reliability benefits. If reducing fuel costs makes some base load plant costs energy related (*i.e.,* capital substitution), it is equally valid that a portion of the higher variable costs a utility incurs are demand-related because the utility chooses to spend less capital (*i.e.*, fuel substitution). (Tr. 3167-3168). PEF has made no such adjustment for these costs. (Tr. 3170).

In addition, PEF asserts that it has spent twice as much capital on base load and intermediate capacity than it would have otherwise spent if it had built only combustion turbine (CT) peaking units. This assertion is based on Exhibit No. 113, which quantifies the hypothetical cost of capacity had PEF built only combustion turbines instead of a mix of base, intermediate and peaking capacity. This analysis is flawed because it places a value on capacity of only \$209 per kW while the current cost of capacity is at least \$329 per kW. (Tr. 3171). Exhibit No. 191 demonstrates that by restating the capacity value from \$209 to \$329 per kW, PEF is spending less than 20% of capital for reasons other than maintaining system reliability.[41]

The concept of the breakeven point is significant because once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. Conversely, if it is projected that a unit will run for a sufficient number of hours, then the intermediate or base load unit will be more economical. (Tr. 3172).

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity. (Tr. 3172).

Finally, the 12CP-50% AD method suffers from double-counting. This is because the method allocates production plant costs partially on average demand and partially on coincident

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[41] This does not mean that 20% of production plant should be allocated on average demand. This is because <u>all</u> production from a specific plant (*i.e.*, kWh sales) is not the critical factor in deciding what type of plant to install. It is only the energy up to the economic breakeven point between base/intermediate and peaking capacity that is relevant to the decision. (Tr. 3172).

peak demand. Double-counting occurs because average demand (which is the equivalent of year-round energy consumption divided by 8,760 hours) is also a component of the coincident peak demand. By allocating some plant costs relative to average demand and some relative to coincident peak demand, energy is counted twice: once by itself and a second time as a subset of the coincident peak demand. If year-round energy is analogous to base load units, which supply capacity on a continuing basis throughout the year, then it follows that the only time intermediate and peaking units would be needed is to meet system demands when they are in excess of the average year-round demand. Energy allocation advocates improperly allocate the cost of this additional capacity relative to *total* coincident demand, rather than the *excess* demand. (Tr. 3174-3175).

PEF's proposed 12CP-50% methodology should not be adopted and the Commission should retain the 12 CP and 1/13 AD methodology.[42] PEF's proposal would improperly replace the long-standing "cost-causation" standard with a "costs follow the benefits" standard that focuses solely on allocating production plant costs and, thus, is not consistently applied. As such, it fails to recognize the substitution of fuel costs for capital costs in providing certain ancillary services necessary to maintain reliability. Further, capacity is significantly undervalued, the amount of investment spent to save fuel costs is significantly over-stated, and the method double-counts CP demand. (Tr. 3176).

FIPUG is not unaware of the Commission's cost of service decision in the Tampa Electric rate case where it indicated an inclination to move to a methodology with a greater energy weighting.[43] While FIPUG disagrees with such an approach, if that is the Commission's

[42] This is the cost of service methodology proposed by FPL in its pending rate case. (Tr. 1534).
[43] In re Tampa Electric Rate Case, Docket No. 080317-EI, *Order No. PSC-09-0283-FOF-EI.*

determination in this case, the Commission should adopt the average and excess (A&E) method. This method is recognized in the NARUC Cost Allocation Manual. (Tr. 1527).

Under A&E, a portion of production/transmission plant costs equal to the utility's annual system load factor (or 53% as projected by PEF during the 2010 test year) would be allocated on average demand. The remaining costs would be allocated on the difference between a class' maximum demand and its average demand, which is the "Excess Demand" (ED) component of the A&E formula. (Tr. 3177).

A&E recognizes dual cost-causers. First, some plant is required for year-round operation (*i.e.,* Average Demand). High load factor customers that use electricity throughout the year would receive a larger share of the Average Demand. Second, the remaining plant is required for cycling (*i.e.,* Excess Demand). That is, generators must also be capable of load following from the minimum loads that occur at night to the peak loads that occur on hot summer afternoons. Low load factor customers have variable demands, which require more cycling capacity than do high load factor customers. This is reflected in apportioning more Excess Demand to the lower load factor classes. (Tr. 3178).

In his prefiled direct testimony, PEF witness Slusser supported the use of a 50% energy weighting for production capacity by observing that there are many utilities that use the A&E method because it effectively weights energy responsibility by a utility's load factor, which is generally in the 50% to 60% range. (Tr. 1499). When witness Slusser took the stand on direct, he withdrew this part of his testimony. Despite having spent many hours on his testimony, witness Slusser admitted that he had not done his "homework" on this method, (Tr. 1528), and then attempted to change his view. This calls into question whether PEF is truly trying to find the method that follows principles of cost causation or whether PEF is looking for the answer it prefers.

Finally, as to the allocation of transmission plant costs, the Commission should use the summer/winter coincident peak (SWCP) method. As discussed above, the PEF system is highly seasonal, with peak demands occurring in both the summer and winter months. Thus, the SWCP method appropriately reflects cost-causation. (Tr. 3179). (See Exhibit No. 193 for allocation factors using this method).

ISSUE 91: If the Commission approves a cost allocation methodology other than the 12 CP and 1/13th Average Demand, should all cost recovery factors be adjusted to reflect the new cost of service methodology?

POSITION: *Yes, provided that the interruptible credit is adjusted to reflect its full value.*

ISSUE 92: How should any change in revenue requirements approved by the Commission be allocated among the customer classes?

POSITION: *If an increase is granted, no rate schedule should receive an increase greater than 150% of the system average base rate increase. This has been the Commission's long-standing practice and policy. To do otherwise would result in excessive increases to certain classes, some of which are over 50%.*

DISCUSSION

These issues relate to the apportionment of any base revenue change to each rate schedule. Base revenues should reflect the actual cost of providing service to each rate schedule as closely as practicable. However, this Commission has consistently limited the immediate movement to cost based on principles of gradualism and rate administration. Gradualism is a concept that is applied to prevent any group from receiving an overly-large rate increase. That is, the movement to cost-of-service should be made gradually rather than all at once because an abrupt change would result in rate shock to the affected customers.

PEF's cost of service proposal would result in some rate schedules seeing tremendous increases which would violate principles of gradualism. The magnitude of these increases is wholly inappropriate and should be rejected. (Tr. 3217).

Exhibit No. 195 shows that the proposed relative increases for the GSD-1, IS-1/IS-2, and SS-3 rates would exceed 150% of the system average increase which is the standard the Commission applies. PEF's proposal is clearly contrary to this Commission's practice and precedents and should be rejected. PEF tries to mask this policy violation by showing that its proposed class revenue allocation would result in no cost-of-service class receiving a relative increase higher than 150% of the retail average increase. However, the appropriate standard is to examine the impact on rates. (Tr. 3185).

Thus, the disagreement between FIPUG and PEF centers on whether the 150% limitation is to be applied by *class* or by *rate schedule*. The Commission has used those two terms interchangeably. For example, in the Gulf Power rate case, the Commission said:

> No increases are allocated for the Other Outdoor (OS-III), Standby (SBS), Real Time Pricing (RTP), and Large High Load Factor (PX/PXT) rate schedules because they are all significantly above parity.[44]

Rate impact is further exacerbated because any cost of service methodology approved here will also apply to recovery of clause expenses and result in significant increases. (Tr. 1534, 1538). Exhibit No. 317 demonstrates that the IS-1 and IS-2 rate schedules would see their rates increase by 64.8%; the GSD-1 class would see their rates increase by 57.1% if PEF's cost-of-service methodology is approved. These are 1.9 and 1.7 times the system average increase. Thus, such increases are beyond the bounds of reasonableness. Even if the Commission uses the "class" approach, which FIPUG opposes, Exhibit No. 317 demonstrates that gradualism

[44] In re: Request for rate increase by Gulf Power Company, Docket No. 010949-EI, *Order No. PSC-02-0787-FOF-EI* at 80, emphasis supplied.

principles have been violated.

ISSUE 95: Should the Commission approve PEF's proposal to eliminate its IS-1, IST-1, CS-1, and CST-1 rate schedules and transfer the current customers to otherwise applicable rate schedules?

POSITION: * No. The Commission should retain the IS-1, IST-1, CS-1 and CST-1 rate schedules. These are separate and distinct schedules which should be maintained. PEF has not demonstrated that these schedules are not cost-effective. In fact, a study performed by PEF shows that PEF projects a need for additional non firm load.*

DISCUSSION

PEF has made *no* demonstration that interruptible load served under the IS-1 and IST-1 rate schedules is not cost-effective. And in fact, the evidence demonstrated exactly the opposite. PEF projects a need for additional cost-effective non-firm load and provided an updated cost-effectiveness test that shows that the resulting credit for interruptible customers should be $10.49 per kW-Month. (Exhibit No. 198).

Interruptible power is a very valuable resource for Florida. Interruptible power is a tariff option that allows a utility to curtail interruptible load when resources are needed to maintain system reliability; that is, when there are insufficient resources to meet customer demand, a utility can interrupt service. This allows the utility to maintain service to firm (*i.e.*, non-interruptible) customers. Interruptible power, thus, is a lower quality of service than firm power. PEF does not include interruptible load in determining the need for additional capacity. (Tr. 3189).

The interruptible tariffs have been in place for decades. They have been (and currently are) a valuable resource to PEF and to the state as a whole. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that service will be maintained for the firm customer base. Such interruption often causes production processes of interruptible customers to be shut down resulting in economic losses for the interruptible customer. (Tr. 3190).

In addition, the Florida Reliability Coordinating Council (FRCC) requires that all reserve sharing groups and balancing authorities maintain adequate Contingency Reserves to cover the FRCC's most severe single contingency, which is currently 910 MW. Of this amount, PEF's contingency reserve requirement is currently 179 MW.[45] PEF must supply this reserve when called upon to replace reserve capacity that is no longer available due to sudden forced outages of major generating facilities or the loss of transmission facilities. (Tr. 3189-3190).

Contingency reserves may be comprised of those generating resources and Interruptible Load that are available within 15 minutes. Thus, PEF could count interruptible power in meeting its contingency reserve obligations. (Tr. 3189-3190). The Commission should not close these rates but rather should nurture this important resource.

ISSUE 96: Is PEF's proposal to grandfather certain terms and conditions for existing IS-1, IST-1, CS-1, and CST-1 customers transferred to the IS-2, IST-2, CS-2, and CST-2 rate schedules appropriate?

POSITION: *Yes. If the existing IS-1, IST-1, CS-1, and CST-1 customers are transferred, all terms and conditions for service to those classes should be grandfathered. including the 60 month transfer requirement.*

ISSUE 98: Are PEF's proposed customer charges appropriate?

POSITION: *No position.*

ISSUE 99: Are PEF's proposed service charges appropriate?

POSITION: *No position.*

ISSUE 100: Is PEF's proposed charge for Temporary Service appropriate?

POSITION: *No position.*

[45] *FRCC Handbook*, FRCC Contingency (Operating) Reserve Policy, Appendix A, November 2008.

ISSUE 101: Is PEF's proposed Premium Distribution Service charge appropriate?

POSITION: *No position.*

ISSUE 107: What is the appropriate method of designing time of use rates for PEF?

POSITION: *No position.*

ISSUE 108: What are the appropriate charges under the Firm, Interruptible, and Curtailable Standby Service rate schedules?

POSITION: *This is a fall out issue of the cost of service study.*

ISSUE 109: What is the appropriate level of the interruptible credit?

POSITION: *The credit for interruptible customers should be $10.49 per kW-Month to reflect the current value of the credit. PEF provided an updated cost-effectiveness test that shows that this is the appropriate value for the credit.*

ISSUE 110: Should the interruptible credit be load factor adjusted?

POSITION: *No. PEF's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach incorrectly assumes that load factor and coincidence factor are the same. The interruptible class has a 61% billing load factor. However, the average coincidence factor (with PEF's monthly system peaks) is 68%. Further, curtailments can occur at any time, not just during the system peaks. Thus, the Interruptible Demand Credit should apply to the amount of load that PEF is not obligated to serve during an interruption event.*

DISCUSSION

Issues 109 and 110 relate to what the interruptible credit should be. First, the value of the interruptible credit (calculated by PEF to be $3.31 per kW, which is then load factor adjusted – that is reduced) is greatly understated. In this case, PEF provided an updated cost-effectiveness test that shows that the resulting credit for interruptible customers should be based on a capacity value of $10.49 per kW-Month. Exhibit No. 279 provides PEF's own most current calculation of the latest rate impact test (RIM) as it applies to interruptible load. Thus, PEF's analysis shows the credit is far in excess of the $3.31 PEF recommends.

PEF has proposed to reduce the interruptible credit that IS-1 customers receive by 44% by transferring IS-1 customers to IS-2. The credit for Schedule IS-2 customers is $3.31 per kW-month of load factor adjusted demand. PEF is proposing to eliminate Schedule IS-1 and move customers to Schedule IS-2. The combined IS-1/IS-2 class is projected to have an average billing load factor of about 61%. This would result in an average load-factor adjusted credit of $2.02. Thus, the Company's proposal would result in a 44% reduction in the interruptible credits currently paid to Schedule IS-1 customers, despite the fact that even the current credits are too low. (Tr. 3191-3192). PEF witness Slusser admitted that no IST-1 customer could qualify for the proposed $3.31 credit under the IST-2 rate because no customer operates at a 100% load factor, which is necessary to get the full credit. (Tr. 1558). Customers should be paid the full credit based on the amount of load available for curtailment. PEF's load factor adjustment is inappropriate for several reasons.

First, PEF's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach assumes that load factor and coincidence factor are the same. They are not. The interruptible class has a 61% billing load factor. However, the average coincidence factor (with PEF's monthly system peaks) is 68%. Thus, the Interruptible Demand Credit should not be less than $7.13 per kW-Month ($10.49 x 68%) of billing demand. (Tr. 3193).

Second, curtailments can occur at any time, not just during the system peaks. Thus, the Interruptible Demand Credit should apply to the amount of load that PEF is not obligated to serve during an interruption event. (Tr. 3193).

To measure this benefit, the amount of 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. For example, a customer that operated an average load of 10,000 kW during on-peak hours of the prior calendar year would receive a credit based on 10,000 kW. Some utilities use this methodology. (Tr. 3193-3194).

Alternatively, another approach would be to directly measure the amount of interruptible demand in real-time for each customer. The interruptible demand would be average of the daily maximum on-peak demands for the billing month. This process is similar to determining the Generation and Transmission Capacity charges in Rate SS. (Tr. 3194).

ISSUE 111: What are the appropriate energy charges?

POSITION: *PEF's current non-fuel energy charges should remain the same. The non-fuel energy charges PEF proposes are much higher than PEF's actual energy costs. The current non-fuel energy charges for Schedules GSD, CS, and IS already exceed non-fuel energy unit costs at PEF's proposed rates. Thus, any increase allocated to these rates should be applied only to the demand charges. Similarly, any rate decrease should be used to reduce the current non-fuel energy charges.*

ISSUE 112: What are the appropriate demand charges?

POSITION: *Any approved revenue increase that is not recovered in the customer charge should be recovered in the demand charges.*

DISCUSSION

Demand and non-fuel energy charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the non-fuel energy charges are billed on the kWh purchased. (Tr. 3187). However, PEF's proposal for the design of these charges violates these principles and would result in non-fuel energy charges that would be 2 to 4 times higher than PEF's actual costs. (Tr. 3217).

PEF's proposal for the development of such charges is inappropriate. PEF's demand-related costs should be recovered through the demand charge and energy-related base rate costs should be collected through the energy charge. However, PEF's proposed rate design does not follow this practice. Specifically, PEF has underpriced the demand charges and overpriced the energy charges in Schedules GSD, CS, and IS. The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the class cost-of-service study. (Tr. 3187).

PEF's proposed 2010 unit costs and proposed rates for service provided at transmission delivery for the GSD and Interruptible classes are as follows:

Component	GSD		Interruptible	
	Unit Cost	Proposed Rate	Unit Cost	Proposed Rate
Demand Unit Cost ($ per kW-Month)	$10.88	$2.14	$10.30	$5.20
Non-Fuel Energy Unit Cost (¢ per kWh)	0.508¢	2.274¢	0.499¢	1.070¢

(Tr. 3188).

These extreme differentials should be remedied. The current non-fuel energy charges in Schedules GSD, CS, and IS already exceed non-fuel energy unit costs at PEF's proposed rates. Thus, any increase allocated to these rates should be applied only to the demand charges. The current non-fuel energy charges should not change. Similarly, any rate decrease should be used to reduce the current non-fuel energy charges. (Tr. 3188).

ISSUE 113: What are the appropriate lighting charges?

POSITION: *No position.*

ISSUE 114: Should PEF's proposal to revise its Leave Service Active (LSA) provision (tariff sheet No. 6.110) be approved?

POSITION: *No position.*

ISSUE 115: What is the appropriate effective date for PEF's revised rates and charges?

POSITION: *The rates the Commission sets in this proceeding may only apply to customer consumption after January 1, 2010, pursuant to the terms of the Rate Case Stipulation.*

Issue 115A: Are the rates proposed by Progress Energy Florida fair, just, and reasonable, and compensatory as those terms are used in Chapter 366, Florida Statutes, including specifically Section 366.03, 366.041(1), 366.05(1), and 366.06(1), Florida Statutes?

POSITION: *No. Based on the other issues discussed above, the Commission should reduce PEF's rates.*

Issue 115B: In fulfilling its mandate under Section 366.01, Florida Statutes, to regulate public utilities in the public interest and for the protection of the public welfare, and its mandate under Section 366.041(1) to fix fair, just, reasonable, and compensatory rates that consider among other things the value of such service to the public and that do not deny the utility a reasonable return upon its rate base, should the Commission grant any part of PEF's proposal to increase its base rate in this docket?

POSITION: *No. Based on the other issues discussed above, the Commission should reduce PEF's rates.*

DISCUSSION

Given the amount of testimony the Commission heard in this case regarding the difficult economic times facing all Floridians, FIPUG suggests that an "austerity adjustment" like the one recently imposed by the New York Public Service Commission would be appropriate. As the New York Commission stated:

> Expenditures that are reasonable during average or good economic times are not necessarily reasonable when economic conditions are extremely poor. When consumers are experiencing the extraordinary harsh economic realities we see today, a certain measure of frugality is properly expected from utilities and a reprioritizing of expenditures may be needed.
>
> The record provides only general information about the effect of our deteriorating economic circumstances on customers' ability to pay. However, it is not seriously disputed that we are

now experiencing significant weakness in the New York State economic climate. . . . .

In these extraordinary times, we recognize the need for utilities to implement austerity programs to constrain cost and tighten belts to limit discretionary spending. We will require a meaningful further downward adjustment to the Company's revenue requirement amounting to $60 million.[46]

The ruling of the New York Commission is equally applicable to PEF and FIPUG commends such an adjustment to the Commission.

OTHER ISSUES

ISSUE 116: Should any of the $13,078,000 interim rate increase granted by Order No. PSC-09-0413-PCO-EI be refunded to the ratepayers?

POSITION: * Yes. The entire amount should be refunded, as collection of this amount violates the Stipulation Agreement entered into to settle PEF's last rate case.*

DISCUSSION

In Order No. PSC-05-0945-S-EI,[47] the Commission approved a Stipulation and Settlement as to PEF's 2005 rate case. The Stipulation contained numerous provisions that were part of the give and take of the settlement process.

As part of its rate case filing in this docket, PEF sought, and was granted under the proposed agency action (PAA) process an interim rate increase of $13.1 million. This interim award violates the terms of the Stipulation.

The Stipulation provides at paragraph 7:

> If PEF's retail base rate earnings fall below a 10% return on equity as reported on a Commission adjusted or pro-forma basis on a PEF monthly earnings surveillance report during the term of the Agreement, PEF may petition the Commission to amend its base rates notwithstanding the provisions of Section 4,

[46] Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Case 08-E-0539, Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers, Case 08-M-0618, *Order Setting Electric Rates* at 342-343, April 24, 2009.
[47] In re: Petition for rate increase by Progress Energy Florida, Inc., Docket No. 050078-EI.

either as a general rate proceeding or as a limited proceeding under Section 366.076, F.S. The Parties to this Agreement are not precluded from participating in such a proceeding, and, in the event PEF petitions to initiate a limited proceeding under this Section, any Party may petition to initiate any proceeding otherwise permitted by Florida Law. This Agreement shall terminate upon the effective date of any Final Order issued in such a proceeding that changes PEF's base rates under this Section. This Section shall not be construed to bar or limit PEF from any recovery of costs otherwise contemplated by this Agreement.

Paragraph 14 states:

Effective on the Implementation date, PEF will not have an authorized return on equity range for purposes of addressing earnings levels, and the revenue sharing mechanism described herein shall be the appropriate and exclusive mechanism to address earnings levels. However for purposes other than reporting or assessing earnings, such as cost recovery clauses and Allowance for Funds Used During Construction ("AFUDC"), PEF will use 11.75% as its authorized return on equity percentage in such cost recovery clauses. Commencing with the Implementation Date the applicable annual AFUDC rate will be 8.848%.

The interim rate statute provides that to show an entitlement to interim rates, a utility must establish it is earning outside of its rate of return. Section 366.071(1), Florida Statutes. By accepting and approving this Stipulation, the Commission recognized that during the period of the Stipulation PEF would operate without a ROE. Because PEF has no ROE pursuant to the approved Stipulation, there is no basis upon which it may seek interim rates and no way that it can fall within the strict parameters of the interim statute.

Contrary to PEF's position, the 10% figure contained in the Stipulation is not an ROE to which the interim rate statute applies. It is simply a trigger which to seek a change in its base rates when its rates fall below that level. Thus, the Commission erred when it awarded interim rates. Such rates should be refunded with interest.

ISSUE 119: Does the creation of a regulatory asset and the deferral of pension expenses from a period covered by the Stipulation approved by Order No. PSC-05-0945-S-EI to a future period violate the terms of the Stipulation and order?

POSITION: *Yes. The Stipulation's revenue sharing mechanism is the sole means through which to address PEF earnings through 2009. Allowing PEF to carry costs into 2010 violates the Stipulation.*

DISCUSSION

PEF seeks to create a regulatory asset to defer over $30 million in pension expense. This deferral is to account for losses its pension plan experienced due to the economic decline *during the period covered by the Stipulation.* Such expenses fall squarely within the time frame covered by the Stipulation, which is the sole mechanism by which PEF may address any expenses during the period of the Stipulation. PEF's attempt to move these costs into a period beyond the Stipulation is an inappropriate shifting of costs to a future period. This is nothing more than the isolation of a particular expense – pension – rather than viewing all expenses together as the Stipulation requires.

As noted above, the 10% figure upon which PEF seeks to rely contained in the Stipulation is not an ROE applicable here. It is simply a trigger which to seek a change in its base rates when rates fall below that level. Thus, the Commission erred when it permitted PEF to defer these expenses beyond the period of the Stipulation and this decision should be reversed.

ISSUE 120: Does the creation of a regulatory asset and the deferral of pension expenses from a period covered by the Stipulation and order to a future period constitute retroactive ratemaking?

POSITION: *Yes. The creation of a regulatory asset violates the prohibition against retroactive ratemaking because it would allow PEF to recover past expenses in future rates.*

DISCUSSION

Permitting PEF to defer its pension expense from 2008 to a future period violates the fundamental language of the Stipulation among the parties requiring all expenses and revenues during the Stipulation to be addressed through the revenue sharing mechanism. Further, permitting PEF to move expenses out of the stipulated period into the future allows PEF to engage in piecemeal ratemaking because PEF will be permitted to defer an expense without considering all other factors, some of which may offset the expense. In addition, such treatment, provides in appropriate guaranteed recovery of these costs; that is, the Commission is guaranteeing that the costs will be recovered in future rates.

ISSUE 121: Does the creation of a regulatory asset and the deferral of pension expenses from a period covered by the revenue sharing provisions of the Stipulation and order to a future period result in double recovery of those expenses?

POSITION: *Yes. PEF's recovery of such expenses incurred during the period of the Stipulation is covered by the revenue sharing mechanism in the Stipulation. This is the sole basis for treating expenses during the Stipulation period.*

DISCUSSION

In essence, PEF's proposal amounts to a form of double recovery of its pension expense. The pension expenses incurred during the period of the Stipulation are covered by the Stipulation's terms. Those terms include the provision that all revenues and expenses are treated *solely* under the revenue sharing mechanism. 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 Stipulation and once in the future beyond the Stipulation. This treatment constitutes an impermissible modification of the Stipulation and results in a double recovery.

ISSUE 122: Should this docket be closed?

POSITION: *Yes. This docket should be closed once PEF's rates are reduced and a final order is issued.*

s/ Vicki Gordon Kaufman

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Brief was furnished by Electronic Mail on this 16th day of October, 2009.

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