BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050078-EI

In the Matter of

PETITION FOR RATE INCREASE BY PROGRESS ENERGY FLORIDA, INC.
_______________________________________/

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE A CONVENIENCE COPY ONLY AND ARE NOT THE OFFICIAL TRANSCRIPT OF THE HEARING, THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

VOLUME 8

Page 1153 through 1323

PROCEEDINGS:	TECHNICAL HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER LISA POLAK EDGAR
DATE:	Wednesday, September 7, 2005
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Hearings Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

P R O C E E D I N G S

(Transcript follows in sequence from Volume 7.)

REBUTTAL TESTIMONY OF

THOMAS R. SULLIVAN

I. Introduction and Purpose of Rebuttal Testimony.

Q. Mr. Sullivan, did you file direct testimony in this proceeding?

A. Yes, I did.

Q. What was the purpose of your direct testimony?

A. The purpose of my direct testimony was to address Progress Energy Florida, Inc's ("PEF's" or the "Company's") capital structure and the impact long-term purchase power contracts ("PPAs") have on our financial policy.

Q. **Have any of the intervenor witnesses addressed PEF's capital structure and the impact of the PPAs on PEF's financial policy in their testimony?**

A. Yes, they have. Mr. Rothschild, on behalf of the Office of Public Counsel ("OPC"), Mr. Gorman, on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs ("White Springs"), and Ms. Brown, on behalf of the Florida Retail Federation ("FRF"), have all filed testimony on these issues.

Q. **Have you read their testimony?**

A. Yes.

Q. What is your understanding of the intervenors' recommendations regarding PEF's capital structure?

A. Mr. Gorman proposes to adjust the Company's proposed capital structure by removing the impacts to the Company's proposed capital structure arising from the Crystal River 3 nuclear unit ("CR3") outage costs incurred by the Company and the off balance sheet obligations related to the Company's PPAs. (Gorman at page 13, lines 8-16). He argues that, even with these adjustments, the Company can achieve its current BBB credit rating.

Ms. Brown proposes to adjust the Company's capital structure by removing the impact of the CR3 outage costs, claiming that this adjustment reduces the Company's equity ratio to 53.86% for financial reporting purposes. (Brown, at page 17, lines 6-7). However, she <u>includes</u> the impact of the PPAs on PEF's equity ratio for financial reporting purposes. In other words, Ms. Brown agrees with PEF's adjustment to take into account the off balance sheet PPA obligations and with PEF's target capital structure to obtain a single A rating. In fact, she claims that, even with her CR3 adjustment, PEF's equity ratio will be directly in the middle of the range to achieve the single A rating that the Company has targeted. (Brown at page 17, lines 7-8).

Mr. Rothschild proposes to adjust PEF's proposed capital structure by removing the impacts of the CR3 outage costs and the PPAs on PEF's capital structure. He goes further though and proposes to apply the Progress Energy, Inc. ("Progress Energy") consolidated capital structure on PEF's rate base, thereby reducing the Company's equity ratio even further to 41.8% equity, a reduction of over

20% in the equity ratio from the Company's proposed capital structure for financial reporting purposes and almost a 10% reduction in the Company's current book equity ratio. Neither Mr. Gorman nor Ms. Brown go this far; they accept that Progress Energy's capital structure should not be substituted for PEF's capital structure.

Q. Do you agree with the intervenors' recommended adjustments to PEF's proposed capital structure?

A, We certainly accept Ms. Brown's agreement to our adjustment to account for the impact of the off balance sheet PPAs on our capital structure. We disagree, however, with her adjustment and the other intervenors' adjustments to eliminate the impact of the CR3 outage on PEF's capital structure. Mr. Portuondo will address their recommendations with respect to the CR3 equity adjustment to the Company's proposed capital structure.

With respect to Mr. Gorman's and Mr. Rothschild's proposed recommendations regarding the financial impact of the PPAs on PEF's capital structure, their adjustments are inaccurate and miss the point of the very financial impact the PPAs have and that the Company is trying to address with its proposed capital structure. Simply put, they recommend that this Commission should ignore the PPAs' financial impact on the Company's capital structure. Ignoring this financial impact, however, will further weaken the Company's credit profile and thus its access to the credit markets when credit is needed the most, placing the Company and its customers at risk of a downgrade with resulting higher costs of capital. In fact, since the filing of my direct testimony, Standard & Poor's ("S&P") has informed us of a change in their calculation of imputed debt associated with these contracts which will increase the amount of debt imputed by $209 million. To ignore this adjustment is to blatantly ignore an obvious adjustment made by S&P when assessing the credit quality of PEF.

Mr. Rothschild's proposal to superimpose Progress Energy's capital structure on PEF's capital structure is, for reasons I will explain, unreasonable and unfair. It will also negatively impact how PEF is viewed by the market, further undermining PEF's credit profile and thereby increasing the Company's risk of a downgrade. Tellingly, none of the other intervenors even suggested such an unreasonable proposal, further indicating the audacity of his recommendation.

Q. What would be the impact on PEF if the Commission were to accept Mr. Rothschild's and OPC's proposed capital structure, return on equity, and $360 million annual revenue decrease?

A. If the Commission accepted Mr. Rothschild's and the Office of Public Counsel's ("OPC's") proposed capital structure and return on equity, the likely result would be a significant degradation of PEF's financial condition given the significant capital expenditures associated with its growing customer base and increasing environmental compliance costs. I would expect the rating agencies would immediately place PEF on a "credit watch" with negative implications while they analyze the impact of the significant reduction from PEF's proposed base revenue increase that Mr. Rothschild's and OPC's proposals would bring about. The impacts would include an immediate and significant reduction in the Company's cash flows, making the

Company more dependent on access to external financing. When a company must access the capital markets to fund any cash flow shortfalls for its nondiscretionary capital spending, the rating agencies view this as a negative development leading to weakening credit ratios. This is the case with PEF, as with any other regulated electric utility with the obligation to serve all new and existing customers.

PEF did not have a choice to reconnect customers during last year's storms and incurred significant expenditures to restore electric service. This is an obligation that cannot be overstated and underscores the importance of having a strong credit rating. Perhaps most importantly, then, the impacts of Mr. Rothschild's and OPC's proposals, if adopted, would signal a dramatic reduction in investor confidence in the Florida regulatory environment, increasing investor perceptions of greater regulatory risk with these and other utility issues. All of these impacts would likely weaken PEF's credit standing and, thus, its credit ratings, serving only to increase the future cost of capital to the Company and its customers.

Q. Why does Mr. Rothschild recommend that Progress Energy's consolidated capital structure should be substituted for PEF's proposed capital structure?

A. Mr. Rothschild's recommendation is not actually based on a reason for selecting the consolidated entity's capital structure for PEF but his reasons for rejecting the Company's proposed capital structure. Mr. Rothschild then <u>assumes</u> the Progress Energy capital structure is reasonable for PEF because the Progress Energy capital structure is similar to (but not the same as) the Progress Energy targeted capital structure and consolidated bond rating.

To explain further, Mr. Rothschild claims that the Company's proposed capital structure will not produce the Company's targeted single A bond rating because on a consolidated basis, according to Mr. Rothschild, the determinative factor affecting the Company's bond rating is the Progress Energy debt. Until the Progress Energy debt is reduced, he claims, nothing will change with respect to PEF's bond rating, no matter what PEF does. He concludes, then, that PEF customers will pay more under PEF's proposed capital structure but receive nothing in return for it.

From this unreasonable premise Mr. Rothschild jumps to the erroneous conclusion that the Company proposed its capital structure in order to subsidize Progress Energy's unregulated operations. Further, he concludes that subsidization is actually occurring, and that PEF's current equity includes Progress Energy debt. To prevent this alleged current and future subsidization of unregulated operations under PEF's proposed capital structure from occurring, he argues the Commission should impose Progress Energy's consolidated capital structure on PEF's rate base.

Apparently recognizing that his recommendation radically reduces even the equity in PEF's existing capital structure, Mr. Rothschild attempts to show that this recommendation will not harm PEF's credit standing thus subjecting PEF and its customers to greater, not lower, costs. He claims the Progress Energy consolidated capital structure is reasonable for PEF because: (1) Progress Energy's current capital structure is close to Progress Energy's targeted capital structure; (2) Progress Energy's current capital structure is sufficient for the BBB rating PEF currently has and that Progress Energy is targeting; (3) the Progress Energy consolidated capital structure allegedly is close to the industry average capital structure for the proxy utility group used by Dr. Vander Weide; and (4) again, the PEF rating is constrained by the Progress Energy debt. As I explain below, all this shows is that Progress Energy is appropriately moving toward its target capital structure; it says nothing about PEF's target capital structure.

II. Capital Structure.

Q. Is it reasonable to apply Progress Energy's consolidated capital structure to PEF's rate base?

A. No. Progress Energy is a holding company with no operations of its own. Rather, Progress Energy's capital structure reflects the consolidated capital structure of many different legal entities that are involved in a variety of different industries. The Progress Energy consolidated capital structure, therefore, does not reflect PEF's capital structure. PEF's cost of capital is a function of its financial capital structure and adjustments to its financial capital structure made by the rating agencies, i.e. the adjustment for the off balance sheet PPA obligations that I will also discuss. It is not a function of Progress Energy's capital structure and it would be inconsistent with well established regulatory practice of using the utility's capital structure when setting rates. PEF's financial capital structure is driven by its specific capital needs given the particular circumstances of its regulatory environment. Simply superimposing the Progress Energy consolidated capital structure onto PEF ignores the realities of PEF's regulatory environment and the capital structure it needs to succeed in that environment. Mr. Rothschild further seems to speculate in his testimony (Rothschild at page 13, lines 19-22) that a subsidiary capital structure may contain equity raised in the form of debt by its parent. This type of transaction, referred to as "double leverage," was addressed by the Florida Public Service Commission ("FPSC" or the "Commission") in Docket No. 780912-TP, Order No. 9551, 1980 Fla. PUC Lexis 184. In that Order, the Commission rejected the use of a double leverage adjustment.

Q. How does PEF's regulatory environment drive PEF's financial capital structure?

A. As I explained in my direct testimony, PEF, like other regulated electric utilities, has the obligation to serve its customers. This obligation arises from the fact that PEF is providing an essential service. Other companies, when market conditions turn and the costs of providing the company's services or products increase beyond the marginal return to the company on that service or product, can and do cut or withhold their investment in production of their services or products until market conditions improve. Regulated electric utilities like PEF do not have that option. They must continue to invest in the capital necessary to provide service to their customers because they have an obligation to provide service under all market conditions. This obligation to serve requires access to capital markets under all market conditions.

Q. Does PEF recover its costs invested in capital from customers?

A. PEF does have the opportunity to recover its reasonable and prudent costs, including costs of investment, from its ratepayers. This is, however, no guarantee that the Company will recover all of its costs and the rating agencies understand that no such guarantee exists. There is also the issue of timing. Adjustments to the Company's recovery of its costs invested in providing service take time especially through base rate adjustments but also through the various recovery clauses. This means the Company begins to recover its costs months and sometimes years after the Company has made the investments. When it comes to capital spending, however, the Company cannot easily change the timing of its spending given the demands of its obligation to provide service. This means that the Company must issue securities whenever those demands must be met, regardless of the market conditions at the time. Accordingly, the Company needs to be able to issue low-cost debt securities during all market conditions.

Q. How does the Company propose to meet its regulatory obligations to provide the necessary capital investment?

A. PEF's target is to obtain a single A rating from all three rating agencies. Its current senior unsecured credit rating is BBB, which is the next-to-lowest investment grade rating. As I explained in my direct testimony, a stronger credit rating assures PEF access to low-cost debt during both good and difficult market conditions. This is necessary for PEF given the significant capital investments the Company faces in the near and long term to meet its obligation to serve.

For example, the Company continues to experience new customer growth and growth in energy demand that, when coupled with the Company's 20% reserve margin requirement, requires the Company to invest in new generation on a regular basis in the future. The Company added a new 500 megawatt generation unit in 2003 and 2005, and will add another new 500 megawatt generation unit in 2007, with expected similar generation investment thereafter. This future generation investment will likely include the consideration of new base load coal or nuclear generation. Similarly, the Company faces substantial capital investments to meet ever growing environmental compliance requirements in the future. Finally, the Company continues to face additional investment requirements in its system to provide the quality electric service that customers demand. All of these capital investment requirements amount to billions of dollars.

The Company must be sufficiently positioned to access the capital markets for these billions of dollars at the lowest cost to its customers under any market conditions. That is, the Company and customer will both benefit if the Company achieves its targeted single A bond rating. The customers are paying for the insurance of better access to low-cost securities to meet the Company's indisputable capital investment needs whenever those investments must be made and they will reap the benefits of the lower cost sources of capital in all market conditions including the difficult ones.

Mr. Rothschild ignores PEF's single A rating target and frequently refers to the Company's target rating as a BBB rating, which is the target rating for Progress Energy consolidated. However, if the consolidated company's target credit rating is used for PEF this will preclude PEF from ever obtaining its single A target credit rating.

Q. Do the intervenors claim that a target single A bond rating for PEF is unreasonable?

A. No. Mr. Gorman apparently believes a BBB rating is sufficient but he does not argue that a single A rating is unreasonable. Mr. Rothschild also argues that a BBB rating is sufficient and that a single A rating cannot be achieved by PEF unless the parent debt is reduced, but he does not claim that a target of a single A rating for the regulated utility would be unreasonable. Ms. Brown seems to assume that a target single A rating is reasonable but erroneously argues that PEF meets the target capital structure for a single A rating excluding the impact of the CR3 outage.

Q. Do you agree with Mr. Rothschild that the Progress Energy debt is the determinative factor in achieving the Company's target capital structure?

A. No. It is one factor among many that the rating agencies take into account when addressing the appropriate credit rating for Progress Energy and its subsidiaries, including PEF. Mr. Rothschild cannot say that the Company will not achieve its single A rating if the parent debt level remains the same any more than the Company can say it will achieve its single A rating. The rating agencies consider the entire picture, taking into account the financial structure and capital needs of the parent company and its subsidiaries in their unique business and economic environments. Equally important for the Company is the outcome of this rate proceeding, as noted in the rating agency reports cited in the Progress Energy annual report at page 25 of Mr. Rothschild's testimony. Whether due consideration will be given to the Company's need to access capital in all markets to meet its substantial capital investment requirements is important to the rating agencies too. The disadvantages from further deterioration of PEF's credit position are clear, if S&P lowers Progress Energy's senior unsecured rating from its current rating, as reported in the annual report, it would be one rating category from a noninvestment grade rating. The effect of a noninvestment grade rating would be to increase borrowing costs. This means that the Company and its customers will pay more for its securities for its capital investment requirements.

Q. Has the Company included parent debt in PEF's equity?

A. No, of course not. Mr. Rothschild is simply wrong in this assertion and he does not support it with anything more than his own speculation about the alleged "special incentive" parent companies have to put extra equity on the books of regulated subsidiaries. (Rothschild at page 13, lines 19-22). Tellingly, the S&P article he cites says <u>nothing</u> about this alleged "special incentive" of holding companies to issue debt and contribute it down to the regulated utility as equity. (Rothschild, Exhibit No. ___ (JAR-14). Further, the article does not support Mr. Rothschild's assertion at page 14, lines 3-5 that "S&P is specifically aware of the problems associated with a high equity ratio reported on the books of regulated subsidiaries when such extra equity disappears at the consolidated level." This is Mr. Rothschild's conclusion, not S&P's. The article addresses the effect regulation can have on the rating of the parent and subsidiary and S&P makes clear that its analysis is conducted on a "case-by-case basis" where the "key is a regulator's demonstrated willingness to protect creditworthiness." (Rothschild Exhibit No. ___ (JAR-14, page 41 of 47). S&P

further explains in the article that "regulatory treatment should be transparent and timely and should allow for consistent performance --- if it is to be viewed positively in the ratings context." (Rothschild Exhibit No. ___ (JAR-14, page 40 of 47).

Q. Will PEF's proposed capital structure subsidize Progress Energy's unregulated operations?

A. No. The capital structure is an important metric when establishing a credit rating. PEF's proposed capital structure is necessary to achieve its target single A credit rating for all the reasons I have previously provided. Progress Energy has a different target credit rating and, therefore, requires a different capital structure to attain that rating. The target credit rating for Progress Energy is based on the business risk of its entire enterprise of businesses. PEF is not asking for an adjustment to its capital structure to off-set parent company debt. It is asking for its proposed capital structure to attain a more financially sound credit rating, as I have explained, to prepare for the capital investments that will be required of PEF now and in the future to meet its obligation to serve.

Q. Does Rothschild Exhibit No. ___ (JAR-1) demonstrate that PEF is subsidizing unregulated operations?

A. No, it does not. In particular, page 3 of Exhibit No. ___ (JAR-1) fails to accurately account for the fact that Progress Energy's consolidated capital structure includes debt issued in connection with the 2000 acquisition of Florida Progress by then CPL Energy, Inc. The calculations performed on page 3 of Mr. Rothschild's Exhibit, therefore, include nearly *$3 billion of debt* that is related to regulated operations but not included in the capital structure of any Progress Energy subsidiary. Including this amount in his calculations grossly misstates the capital structure of the subsidiaries and in no way indicates the level of debt attributable to unregulated operations. As a result, the calculations are meaningless for purposes of determining the appropriate capital structure for PEF as well as the appropriate capital structure for Progress Energy's unregulated businesses. In addition, PEF's MFR Schedule D-2 page 4 of 4 shows the capital structure of the combined nonregulated businesses of Progress Energy. That schedule shows the percentage of common equity to be 65% of the total nonregulated capitalization, significantly different than the percentage calculated by Mr. Rothschild.

Further, as Dr. Cicchetti explains, the synergy benefits that were realized in the merger have been received by customers through the $125 million annual rate reduction over the four years of the base rate settlement agreement. Customers will also continue to receive benefits from the systemic synergies implemented through the combination of the companies in the merger. These benefits were achieved at a cost, namely the debt that was required to bring about the merger. Mr. Rothschild's proposal,to <u>reduce</u> the equity recognized at PEF for ratemaking purposes because of the debt at the parent company that was incurred to accomplish the merger, penalizes the Company for initiating the merger that yielded synergy benefits customers have received. This proposed penalty is simply unfair.

Q. Will Progress Energy continue to pay down the level of debt?

A. Yes, it will. As indicated even by Mr. Rothschild, Progress Energy's target capital structure includes more equity than it currently has, demonstrating that Progress Energy is moving toward greater debt reduction. Progress Energy will continue to do so as part of its plan to reduce the percentage of debt in the consolidated capital structure which will help the company achieve its target credit ratio.

Q. Does Progress Energy's target capital structure and credit rating justify using Progress Energy's capital structure for PEF?

A. No. This is circular. The Progress Energy target capital structure and target credit rating support applying Progress Energy's capital structure to PEF only if you first <u>assume</u> that the Progress Energy capital structure is the appropriate capital structure for PEF, which is what Mr. Rothschild does. As I explained, the target capital structure is an important metric when establishing a credit rating. The long term senior unsecured target credit rating for Progress Energy is BBB but the long term target credit rating for PEF is single A, not BBB. The two target ratings are different and require different capital structures. The guidelines for a company seeking an A rating like PEF with a business risk of "5" is a minimum of 50% equity up to as high as 58% equity. It is this capital structure that PEF is targeting in this proceeding.

Q. Do you agree with Mr. Rothschild's suggestion that the proxy utility group supports the application of Progress Energy's capital structure to PEF?

A. No. When setting a target capital structure, it is totally inappropriate to use anything other than the prescribed guidelines of the rating agencies. Rating agencies provide these guidelines for the obvious reason that issuers would know the appropriate capital structure target for a particular credit rating. There is no need to use a proxy group as suggested by Mr. Rothschild.

Q. Do you agree with Mr. Rothschild's claim that his recommended capital structure will not put downward pressure on PEF's bond rating?

A. No. Mr. Rothschild bases this assertion on the claim that his proposed capital structure is "consistent with the capital structure that has produced the current bond ratings." (Rothschild at page 24, lines 19-20). This assertion simply is not true. Progress Energy's current rating is BBB-, not BBB as reported by Mr. Rothschild, and that rating arises from a variety of factors considered by S&P, one of which is the current capital structure for Progress Energy of 41.8% common equity and PEF of 48.5% common equity, excluding the off balance sheet obligations resulting from the PPAs. (MFR Schedule D-2, pages 1 and 2 of 4). Considering the PPA off balance sheet obligations, the current common equity ratios are even lower, 39% for Progress Energy and 41.2% for PEF. (Id.). What Mr. Rothschild proposes is an identical capital structure for PEF and Progress Energy excluding the PPA off balance sheet obligations. This means a capital structure where the common equity ratio is 41.8% for <u>both</u> Progress Energy and PEF. This is far different from the 41.8% Progress Energy and 48.5% PEF common equity ratios supporting the current bond rating.

III. PPAs Impact on PEF's Financial Policy.

Q. How do the rating agencies treat long-term power supply contracts and what is the impact of their treatment of the PPAs on the Company?

A. As I explained in my direct testimony, while there are differences in methods, they all view long term PPAs with their fixed payments as essentially debt-like in nature. The main effect of the impact of this treatment of PPAs on PEF's financial structure is that the Company is considered to have more leverage than if you calculated its leverage ratio based only on the debt recorded on its balance sheet.

Q. Do the intervenors claim that the rating agencies do not view long term PPAs as debt-like in nature?

A. No, they agree that they do. Mr. Gorman, for example, agrees that credit rating analysts consider off balance sheet purchased power in evaluating a utility's credit. (Gorman at page 11, lines 20-21, page 12, line 1). Similarly, Ms. Brown testifies that "[a]s explained by Mr. Sullivan, the rating agencies treat off balance sheet obligations, such as long term purchased power contract commitments, as additional debt when assigning bond ratings. This practice has the impact of reducing PEF's equity ratio to a level that PEF deems unacceptable." (Brown at page 14, lines 12-16) (emphasis added).

Q. Does Ms. Brown agree with the Company's proposal to address the off balance Sheet impact of the PPA's on PEF's capital structure?

A. Yes, she does. Ms. Brown notes that, as shown in Mr. Sullivan's testimony, "the inclusion of the off-balance sheet obligations in the capital structure reduces the common equity ratio from 55.00% to 47.71%." (Brown at page 14, lines 16-19). She explains that this drops the Company's equity ratio below the range of 50% and 58% for a single A rating. She then notes that PEF makes an adjustment to its equity to allow the equity ratio to fall within the range for a single A rating "once the rating agencies make the off-balance sheet adjustment." (Brown at page 14, lines 19-22, page 15, lines 1-2). She acknowledges PEF's target for a 55% equity structure after recognizing the imputed debt associated with the PPAs and explains that PEF added an amount to equity "equal to the debt it anticipates the rating agencies to impute." (Brown at page 15, lines 4-7). Ms. Brown makes a similar adjustment to her schedule on Exhibit No. ___ (SLB-3, page 2 of 3).

Q. Do Mr. Gorman and Mr. Rothschild agree with PEF's adjustment to account for the impact of the PPAs on PEF's capital structure?

A. No, they do not. They propose that the Commission should ignore the admitted impact the off balance sheet PPAs have on the Company's capital structure, for a variety of reasons, none of which have merit.

Q. What are Mr. Gorman's arguments for rejecting the Company's proposal for recognition of the impact of the off balance sheet PPAs on PEF's capital structure?

A. First, Mr. Gorman argues that the debt-like equivalence of PEF's PPAs is "reduced" based on his reading of the S&P literature. (Gorman at page 13, lines 2-4). He does not explain what he means by "reduced" but there is no real dispute regarding PEF's calculation of the off balance sheet impact of the PPAs as shown on page 8 of my direct testimony. As previously noted, this amount has been increased by S&P due to a change in the discount rate applied to the capacity payments. That is the true impact of the PPAs on PEF's adjusted capital structure for financial purposes, whether or not it is "reduced," and Mr. Gorman does not suggest an alternative figure.

Mr. Gorman and Mr. Rothschild also argue that PEF's current capital structure is sufficient to support its bond rating without PEF's adjustment to account for the impact of the off balance sheet PPA debt. This argument ignores the Company's target capital structure to obtain a single A rating. Neither Mr. Gorman nor Mr. Rothschild contend that a single A rating is unreasonable. And, as I explained before, by improving its credit rating PEF will improve its access to the capital markets, as well as other sources of funds, during all financial markets, good and bad.

Finally, Mr. Gorman asserts that PEF's proposal to recognize equity equivalent to the debt imputed to the Company's balance sheet for the off balance sheet PPAs is inconsistent with the principle of setting rates to recover PEF's actual costs of providing service. Mr. Rothschild echoes this argument, claiming that customers should not pay a return for equity that does not exist. This argument ignores who really determines the overall cost of capital, the market or regulatory bodies. Market forces, not regulatory bodies, determine a firm's cost of capital. In the case of the PPAs, the market recognizes the off balance sheet obligations as debt whether or not regulatory bodies choose to do so in setting rates. This off balance sheet debt must be accounted for because the market, not regulatory cost principles, demands it. And it is the market that will ultimately determine the cost of capital in the long run. Failure to recognize the PPAs, as the market in fact does, places the Company at risk of further weakening financial ratios that will impact the Company's access to capital on reasonably low cost terms when capital is needed the most. In the long run, suppressing these market forces will only lead to higher capital costs – and customer rates – and it will be too late then to adjust PEF's capital structure to take the PPAs into account. The Commission needs to act now to ensure that PEF's capital structure adequately positions the Company to obtain the necessary capital to provide quality service to its customers in all market conditions.

Q. Do you agree with Mr. Rothschild's assertion that PEF is really at 63% equity if placed on the same financial basis that is used by Progress Energy for setting its capital structure by rating agencies?

A. No. All three national rating agencies base their credit rating on a company's adjusted financial ratios. Mr. Rothschild is using the PEF equity ratio on a financial basis before it is adjusted. For PEF, the most significant adjustment made by S&P to its financial based ratios is an adjustment to impute debt associated with the PPAs. This adjustment significantly increases its leverage and reduces coverage ratios and must be taken into consideration.

Q. Do you agree with Mr. Rothschild's claim that the Commission should not take into account the PPAs because Progress Energy does not take them into account?

A. No, Mr. Rothschild is wrong. Progress Energy does take the PPAs at PEF and Progress Energy Carolinas into account as reported on an adjusted financial basis. This is demonstrated by MFR Schedule D-2, page 2 of 4, which shows the adjusted financial capital structure for Progress Energy. Mr. Rothschild relies on the Company's answer to OPC interrogatory number 112 to support his claim that Progress Energy does not make an adjustment to its capital structure to account for the PPAs. What Mr. Rothschild fails to point out is that the interrogatory asked about a debt-to-capitalization ratio referred to in the Company's annual report. Disclosures in the Company's annual reports are made in accordance with Generally Accepted Accounting Principles ("GAAP") pursuant to Securities Exchange Commission ("SEC") regulation. Under the regulation, adjustments such as the one made by rating agencies for off balance sheet PPAs are non-GAAP financial measures that are not reported in the annual report pursuant to SEC regulation.

Q. Have you addressed the principle arguments raised by the intervenors that challenge the Company's proposed capital structure and adjustment to account for the impact of the PPAs on the Company's capital structure?

A. I believe that I have. To the extent that I have not addressed some further argument to the contrary, however, the Company does not agree with it but rejects it for all the reasons that I have provided in my direct and rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

REBUTTAL TESTIMONY
OF
CHARLES J. CICCHETTI, Ph.D.

I. INTRODUCTION

Q. Please state your name.

A. Charles J. Cicchetti.

Q. Are you the same Charles J. Cicchetti who filed Direct Testimony in this matter?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

A. I respond to the Direct Testimonies of several witnesses for Intervenors who filed Direct Testimony criticizing my Direct Testimony. In particular, I will respond to the Direct Testimonies filed by: (1) James Rothschild (Office of Public Counsel ["OPC"]); (2) Hugh Larkin (OPC); (3) Dr. Philip Porter (Florida Industrial Power Users Group ["FIPUG"]); (4) Alan Chalfant (White Springs Agricultural Chemicals); (5) Michael Gorman (White Springs Agricultural Chemicals); Michael Brubaker (White Springs Agricultural Chemicals); (6) Stephen Stewart (AARP); (7) Michael Culver and Charlie Martin (Commercial Group); (8) Sheree L. Brown (Florida Retail Federation ["FRF"]); and (9) Sidney Matlock of the Commission Staff.

Q. Please summarize your Rebuttal Testimony.

A. There are two primary areas on which I focus in my Rebuttal Testimony. First, I explain that none of the Intervenor witnesses seems to fully understand the underlying concept of the benchmarking model I provide and, therefore, they reject or dismiss the importance and relevance of the annual savings of $396.3 million shown by the model as compared to what one would expect based on utility industry performance. Most fail, for example, to take into account the explicit factors, which I included in the model, that capture the external business conditions that Progress Energy Florida ("PEF" or the "Company") has internalized and overcome for the benefit of Florida's electricity consumers. I will discuss how relative prices and the decline in interest rates fit into this context. Here, I will show that certain of the Intervenor witnesses' simplistic arguments lack merit because they claim –without support-- that PEF's prices are relatively high, PEF cannot be the superior performer that the model shows. I will explain why these Intervenor witnesses' logic is flawed, and that when PEF is compared to its peers on a truly comparable basis, PEF is indeed a superior performer.

Second, I will answer the criticisms that have been leveled against my recommendation that the Commission recognize PEF's superior performance when setting its authorized Return on Equity (ROE). I will explain why good regulation does not punish utilities for superior performance and should, in fact, encourage utilities such as PEF that have more than met their side of the regulatory bargain. In so doing, I will also explain the misconception shared by several of the Intervenor witnesses that revenue sharing is not a substitute policy, but is complementary. Here, I will also explain some of the errant thinking that some would attach to the recent storm recovery decision and how this may or may not affect future risk.

Q. Do you address any other issues in your Rebuttal Testimony?

Q. Yes. Several Intervenor witnesses have raised issues and presented seriously flawed analysis. I will address those topics as well because they are used in the Intervenor witnesses' Direct Testimony to recommend two quite negative things: (1) reject my proposed recommendation that PEF's ROE be set at 12.8%, which is 50 basis points higher than Dr. Vander Weide's ROE floor; and (2) to propose a major rate reduction for a utility that is a high performer with very real capital requirements to meet system growth. These other issues include: (1) explaining why PEF's parent company's, Progress Energy Inc.'s (Progress Energy's) capital structure is not appropriate for PEF; and (2) explaining why the consumer benefits from allowing Construction Work in Progress (CWIP) in rate base.

Q. How is your Rebuttal Testimony organized?

A. In Section 2, I rebut those Intervenor witnesses who have misunderstood and criticized my benchmarking analysis. In Section 3, I address those Intervenor witnesses who have criticized my proposal to set PEF's ROE to reflect superior performance. In Section 4, I discuss the capital structure and CWIP issues I described briefly in my previous answer. In Section 5, I summarize my conclusions.

II. RESPONSE TO CRITICISMS OF MY BENCHMARKING ANALYSIS

Q. At page 22 of his Direct Testimony, Dr. Philip Porter on behalf of the FIPUG, claims that your opinion that PEF's superior performance has saved ratepayers $125 million cannot be verified because your "proprietary model" and "reported findings are not open to scrutiny." How do you respond to his criticism?

A. Dr. Porter's criticism is misplaced on several levels. First, he misunderstands my Direct Testimony. In my Direct Testimony, I explain the Translog production model that I use to determine the statistical relationship between a typical electric utility's cost of production and the external business conditions that it faces. These conditions include the local prices of labor, capital, finance, fuel, power, and other production inputs. They also include miscellaneous other business conditions such as operating scale and customer mix, load factor, fuel diversity, etc.. The sample includes data on the operations and production costs of 95 utilities over a nine year time period.

None of the data that I use are proprietary. Most were, in fact, drawn from FERC Form 1 filings. In my response to White Springs Agricultural Chemicals Interrogatory Number 29, I provided a list of the variables used in the Translog model for Total Cost, a summary of the formulas and sources for those variables used in the Translog Total Cost model, and a printout replicating the results from the PEF data and parameter estimates. The form of the model and the general econometric methods used to estimate have been widely used for several decades and are discussed in many textbooks. The econometric model and mathematical logic used, the so-called Translog Production Function and its close cousin, Total Cost Function, are also not proprietary. In fact, this method, albeit complex in structure and its underlying statistical methodology, has been widely used for more than three decades and is included in most advanced econometric textbooks.

None of the above is proprietary in either a legal or pejoratively secret sense. What my firm does claim to be proprietary is the "learned" expertise that we have developed over the years. It is this "learned" expertise that we would not want to share with potential competitors.

Using the Translog Total Cost model, I find that over the last three years for which data was available when I did the analysis (2001, 2002, and 2003), PEF's actual total costs of producing electricity were 12.7%, or $393.3 million per year less than I would expect based upon the electric utility industry's Total Cost of Production Model and given the local business conditions faced by PEF and a normal or industry level of operating efficiency. I also show and discuss the sector-by-sector breakdown of these costs (*e.g.*, labor, capital, fuel, etc.) in my Direct Testimony.

Intervenor witnesses either fail to grasp what I did or they seek to redirect the discussion away from the nearly $400 million advantage that PEF achieved to a separate and distinct $125 million annual savings that PEF and others established through a settlement in the last rate case as part of its merger that formed Progress Energy. In other words, PEF ratepayers benefit from having PEF be their electric supplier as compared to an efficient utility, which is represented in the Translog Total Cost model. My reference to the $125 million in customer savings is specifically to the indisputable and guaranteed $125 million in annual rate reductions through December 31, 2005 provided to customers by PEF under the settlement agreement reached in 2002. These customer savings should not be in dispute because retail rates were reduced in the 2002 settlement. These are savings that customers have received due to PEF's confidence that it could achieve merger related synergies and efficiencies. Verifying these savings has nothing at all to do with my benchmarking model, which compares PEF to an industry performance standard and does not consider PEF's performance in achieving synergy savings. No one disputes that ratepayers are paying $125 million per year less in rates under the 2002 settlement.

Q. In what other way is Dr. Porter's Direct Testimony incorrect?

A. Dr. Porter implies that the model is some mysterious black box that is not subject to scrutiny. This is also not accurate. The model is based on a rich scientific literature that spans more than thirty years. The methodology that I use is not new or unknown, and the research methods utilized are discussed in many textbooks that describe the theory, applications, and methods used in Translog Production and Total Cost Models. While I consider the accumulation of information and consistency checks related to the vast amount of data that are used in the model to be proprietary, my findings are certainly open to scrutiny. The fact that Dr. Porter chose not to take the time to do so, or simply did not address or interpret the economic theory underlying the analysis, should not enable him to dismiss the model's results. I devoted 10 pages in my Direct Testimony explaining how the model worked, the data that was used in the analysis, and my findings and conclusions. I also disclosed specific data and model detail in answering interrogatory questions.

The model is based on the well-established theory of production cost, which holds that cost is a function of input prices and one or more measures of operating scale. Cost may also, in principle, be a function of miscellaneous additional business conditions. All business conditions that appear in the model have plausible and statistically significant parameter estimates. In summary, my model is anything but a black box that confounds earnest appraisal.

The Translog form is designed to impose as few restrictions as possible on the shape of these relationships. Alternative functional forms, such as the Cobb Douglas, are simpler but impose more restrictions on relationships.

There is nothing complicated in economists explaining Total Costs as a function of the quantity of inputs used and their respective prices. In the Translog approach, there are some additional constraints that complicate the statistics, none of which are particularly complex ideas. For example, the sum of the various individual costs components is constrained to equal Total Cost. This is usually expressed in percentage terms. Therefore, the sum of the cost components in the estimated regression model is constrained and must sum to one hundred percent.

As I explained in my Direct Testimony, the Translog Total Cost model included various key cost drivers (*e.g.*, labor prices, capital prices, energy and fuel prices, etc.). The model then took into account differences between utilities (*e.g.*, differences in peak demand, customer growth, percentage of residential customers, etc.). The Translog Total Cost model imposed statistical restrictions for consistency and economic logic. This model is widely used in business, industry, and regulation. In fact, while we have used the Translog Total Cost model in regulatory settings, we more typically use the model in internal benchmarking analyses for utilities that seek a consistent and unbiased assessment of how their performance stacks up against other similarly situated utilities. This offers perhaps the strongest validation of the value and utility of the Translog Total Cost model.

None of the above is a secret to economists, and graduate textbooks in econometrics typically explain the approach in some detail.[1] Before this approach was developed, there were alternate, more rudimentary production cost models, such as the well-known Cobb-Douglas Method. These earlier production and cost models have mostly been replaced by the Translog approach because the latter reflects economic theory.

This is the underlying logic economists use to translate engineering and business decisions that seek to minimize the costs of their inputs in producing the products they sell. There is nothing secretive about any aspect of this approach or statistical methodology. That said, I have applied this logic for a relatively large sample of 95 utilities over nine years to determine a Translog Total Cost model for electric utilities in the United States. This logic establishes the basis for

[1] See for example, Greene, William H, Econometric Analysis, Fourth Edition, Upper Saddle River, N.J., Prentice Hall, 2000; Berndt, Ernest R., The Practice of Econometrics: Classic and Contemporary, Reading, Mass., Addison Wesley Publishing Co. 1991. The actual econometric method is known to practitioners as Seemingly Unrelated Regression with Heteroskedasticity. This method extends the Ordinary Least Squares method to reflect the constraints discussed in the text.

statements that firms such as PEF, which statistically significantly beat this average or expected total cost target, are in fact beating an average or target based upon an approach tied to a foundation of least cost efficiency.

Dr. Porter attempts to dismiss this voluminous and widely accepted body of work by asserting that my model is "proprietary" and "not open to scrutiny," while ignoring that the model uses widely used and accepted econometric formulas. This is not a valid critique. Indeed, we have turned over the statistical model in this proceeding.

Additionally, as I stated very clearly in my Direct Testimony, my model shows that since the merger was completed, PEF has demonstrated a 12.7% cost advantage over a utility of normal efficiency facing the same unique characteristics as PEF. Put another way, PEF's actual total cost is less than what the Translog Model, with a high R^2 of about 98.5% (a high degree of statistical accuracy), predicts for PEF. As I explained in my Direct Testimony, this amounts to about a \$400 million per year savings relative to other utilities with similar characteristics that also attempt to minimize their total production costs. This is not the \$125 million in annual savings related to merger synergies that Dr. Porter discusses.[2] He is confused and incorrectly assumes these two estimates of savings are the same concept.

Q. Dr. Porter also asserts at page 22 lines 12-14 of his Direct Testimony that the

[2] The estimated \$400 million in savings for PEF as compared to an efficient utility most likely includes some or all of the \$125 million in efficiency related to the merger that customers have received in annual revenue requirement reductions.

PEF could have saved $300 million per year simply by refinancing its $10 billion in debt. Is he correct?

A. Dr. Porter's statement is misleading in several respects. He appears to be comparing the guaranteed annual reduction of $125 million provided in the Company's 2002 rate case settlement to a reduction in utility bond rates dating from 1993. I must point out that Dr. Porter is using Progress Energy's $10 billion in debt, which includes $3 billion in merger related debt, and not PEF's long-term debt. Schedule D-2 shows that PEF's long-term debt for 2004 was $1.7 billion. Thus, Dr. Porter overstates his argument.

Regardless, as I discussed above, Dr. Porter is confused as to the $125 million, which represents guaranteed annual base rate reductions through the end of 2005. These $500 million in savings over four years are quite distinct from the annual cost advantages PEF has achieved and demonstrated in the statistical model, which are about $400 million per year.

Dr. Porter is also rather disingenuous when he takes interest rate reductions over a 12 year period, applies the cumulative total to Progress Energy's total debt, and then compares these purported reductions to annual savings based on a three year analysis of costs, implying that PEF has kept the savings for itself. He is wrong. Corporate debt is issued over many years. Corporate debt is often refinanced, just like home mortgages. The prevailing market conditions at the time of issuance and best practices in finance would establish the terms and costs of refinancing PEF's prior or embedded debt. Dr. Porter seems to ignore this fact.

Furthermore, all utilities included in the Translog Total Cost analysis would have had the same opportunity to refinance, and undoubtedly did refinance over the same very long time period. Some of these savings between rate cases, when new embedded debt costs are reset, are offset by rising costs for other factors of production that also occur between rate cases. One should not, in isolation, look at one expense category (debt) where costs decline, and claim all the savings for ratepayers without also considering the totality of all cost categories, including the categories that increase. The Translog Total Cost model considers the totality of all cost categories, including the categories that increase. And, recall that the statistical model shows that when all cost categories are considered, some decline and some, such as fuel, increase. Nevertheless, PEF's costs are 12.7% below what one would expect of a similarly situated utility. This results in annual cost savings of about $400 million above the savings and increases experienced across the utility industry

Q. **At page 12 of his Direct Testimony, Mr. Alan Chalfant criticizes your benchmarking analysis. Please respond to his critique.**

A. Mr. Chalfant states that he was "unable to trace the output" of my model, but that he has no reason to expect that the model is "not numerically accurate." He states that he is troubled, however, by my characterization of the results. He references PEF's responses to White Springs' Second Set of Interrogatories, No. 33a to support his contention that my benchmarking analysis, which revealed PEF's costs were 12.7% below what I would have expected for a similarly situated utility, was "highly dependent on the factors that are selected for inclusion" in the model. It is difficult to fathom exactly what Mr. Chalfant's criticism is.

I provided a list of variables, printouts, and text to describe the sector by sector results. I also discussed how I interpret the output and why I think specific results were found in the analysis. Using regression analyses to determine the interdependence of many variables is commonly accepted and widely used as a reasonable and valued scientific and public policy approach.

In PEF's response to White Springs Second Set of Interrogatories 33a, I explained that the term "efficient" referred to the performance standard of the typical or normal utility in the industry, which is presumed to have the same underlying characteristics as PEF. I could add for clarity that efficient also means "least cost." Based on a statistical model for a utility of typical efficiency, the Translog model estimates what the total costs would be. I then compared these PEF estimates or predictions to PEF's actual costs to determine PEF's relative cost advantage of 12.7% per year over three years.

Q. Does Mr. Chalfant have a more specific critique of your model?

A. No. However, at page 13 of his testimony, he argues that if PEF were truly a low cost supplier, that fact would be reflected in rates and that it would be expected to have lower rates than other utilities in the region. Its rates are lower than TECO's and similar to FP&L's. As for Gulf Power, PEF's location on the peninsula and the resulting transmission constraints implies higher prices for power and generation fuel. Furthermore PEF cannot match the purchasing power of the mammoth Southern Company and does not have access to its low-price power pool. Note finally that PEF has a much more costly demand mix due to the unusual importance of residential demand in its service territory. For these and other reasons, it is quite possible for PEF to have better performance than Gulf Power despite the higher prices it charges. Mr. Chalfant's attack is strange because the model is based on national, not regional data. He then refers to Mr. Brubaker's testimony that suggests PEF is one of the highest price suppliers in the Southeastern United States. This is a thinly veiled attack on the Translog model's credibility. Mr. Chalfant provides no analysis and fails to explain how and why he would expect other regional utility companies to perform.

Q. How do you respond to Mr. Brubaker's assertions starting at page 5 of his Direct Testimony that PEF is one of the highest cost suppliers in the Southeastern United States?

A. Mr. Brubaker's "analysis" demonstrates the difference between a scientific analysis and a non-scientific one. He considers partial results (*i.e.*, prices for specific customer categories and usage levels). Mr. Brubaker fails to consider: (1) differences in circumstances; (2) uniquely different tariff design and cost allocation; and (3) variation in regulatory and restructuring circumstances.

In the Translog analysis, differences in business conditions are built into the analytic and statistical analyses. Mr. Brubaker and others in this case, make no attempt to determine or to correct their relative price comparisons for these and other very significant differences. For example, virtually all of the other companies in Mr. Brubaker's southeast sample are much closer to low-cost coal sources.

Consider two utility companies. The first utility is growing rapidly and adding relatively expensive residential customers. Some of this additional cost may be financed out of depreciation expense and some may require new debt and equity. Now consider a second utility that is not growing. That utility has cash flow available from prior investments that are currently being depreciated. The two utilities would have different capital requirements, different costs of service, different current revenue requirements, and different relative prices.

The Translog analysis I provided went to great lengths to identify the many challenges that an efficient utility must face in managing its production costs. I then took the unique characteristics that describe PEF, which I provided to the Intervenors in this case, and estimated the costs that the model predicts for PEF. I then compared this estimate to PEF's actual costs to determine whether PEF had achieved costs that were above or below what the model predicts and I would have expected. Contrast this to Mr. Brubaker's analysis where he simply lines up rows of prices for various services for utilities across a region of the Southeast United States without any regard to or analysis of the varying circumstances facing the utilities he chose to analyze.

There are additional differences in what Mr. Brubaker attempts and what would be a reliable or sensible effort. There are, for example, differences in how utility commissions allocate costs between industrial, commercial, and residential customers. In addition, tariffs are multipart, and differences in customer use can cause different monthly bills. Again, differences across states and utilities in tariff design and customer use are very commonplace.

The Translog model is a cost analysis. It is not a tariff or specific customer price analysis for a multi-product firm such as an electric utility where voltage, time of use, and other factors vary and affect the unit prices charged. Comparing prices by customer type and use would be more complex and require much more data to attempt to explain a plethora of price differences for specific customer categories across utilities in the United States than what I have done, which is to explain utility cost variations.

Q. **What type of circumstances or conditions might affect PEF's relative position with respect to prices in the Southeast part of the United States?**

A. Comparing PEF's rates to other electric providers in the Southeast without adjusting for factors that affect prices, tariffs, and cost allocations is not valid. There are significant differences that make any such simplistic comparison inappropriate. For example, every utility has a unique mix of residential and commercial/industrial customers. This mix has an effect on the utility's load factor. The fact that PEF has a significant and growing residential component to its load, coupled with a relatively low industrial percentage component, affects PEF's costs, allocations, and prices.

Location can also be significant and can have very significant and different cost effects on utilities even though all are located in the large Southeastern region of the United States. For example, PEF is located far from sources of coal and natural gas, and must incur greater transportation costs than utilities in the Southeast that are located closer to the coal and natural gas production. These coal transportation expenses, plus environmental considerations, affect PEF's fuel and purchase power choices. Furthermore, the price for natural gas has increased several-fold over the past few years, making those utilities with access to relatively inexpensive coal and sizeable nuclear fleets less expensive than PEF.

PEF, as do the other utilities located in peninsular Florida, has significant transmission constraints at the Florida border that reduce its access to lower cost generation from outside the peninsula. These are just some of the reasons why PEF's costs and prices are what they are. In the Translog model, these types of differences and consequences, which affect production and Total Cost, are built into the analysis. Mr. Brubaker and others make price comparisons that are extremely misleading because they omit such relevant price and cost differences. This is precisely why the Translog model, which adjusts and corrects for such differences when discussing the total cost level and efficiency of a particular utility, is more sensible and reliable. Mr. Brubaker and others do not attempt to make such adjustments in their analyses of relative prices.

Q. Is there a group of utilities that would make a more appropriate peer group with which to compare PEF?

A. Yes. However, such a comparison is not really necessary or helpful. The Translog model is better suited for making cost performance appraisals for the reasons I have already discussed. That said, if one were to try to use Mr. Brubaker's relative price analysis, a more appropriate peer group would clearly be the other peninsular Florida investor-owned utilities. I would exclude Gulf Power from this analysis because it is effectively located outside of the peninsula transmission constraint I discussed above and has access to lower-cost wholesale power. Each utility also is in a single state, reducing some tariff differences that are likely across states. Thus, we might sensibly compare PEF's prices to TECO and FPL. In such an analysis, PEF compares quite favorably, especially with respect to the commercial/industrial prices with which Mr. Brubaker and his client are most concerned. This is particularly impressive given that PEF has an unusually large residential component, and PEF has a lower system load factor than either Tampa Electric or Florida Power & Light. For example, in 2003, PEF's load factor (49.5%) was lower than Florida Power & Light (61.3%), Gulf Power (54.2%), and Tampa Electric (56.4%).[3] This is due in part to the greater importance of residential demand.

Q. Have you compared PEF's prices to the two other IOUs located in Florida's peninsula?

A. Yes, I have. The Florida PSC publishes electric industry data every year. The most recent is from 2003 and demonstrates that PEF's prices, especially for commercial/industrial rates compare favorably to the rates of IOUs located in Peninsular Florida.

---

[3] Statistics of the Florida Electric Utility Industry 2003, published September 2004 by the Division of Economic Regulation, Florida Public Service Commission, page 28.

I will begin with residential prices. Table 1, compares the price of residential service for the three Peninsular Florida IOUs for various monthly use levels.

Table 1
Price of Residential Service
31-Dec-03

Utility	Minimum Bill	100 KWH	250 KWH	500 KWH	750 KWH	1000 KWH	1500 KWH
FP&L	$5.25	$13.07	$24.82	$44.40	$63.95	$85.85	$129.65
TE	$8.50	$16.83	$29.33	$50.15	$70.98	$91.79	$133.44
PEF	$8.03	$15.39	$26.43	$44.84	$63.23	$81.62	$123.43

Source: Statistics of the Florida Electric Utility Industry 2003 (FPSC)

When compared with this more relevant and similar group of utilities rather than, as Mr. Brubaker and others do, all the IOUs in the entire Southeast region of the United States, PEF's residential prices/bills compare favorably, even though PEF's load factor, due to a high residential share, is lower than either Florida Power & Light or Tampa Electric.

Table 2 compares the bills of the three IOUs' commercial and industrial service.

Table 2
Price of Comercial and Industrial Service
31-Dec-03

Utility	75 KW 15,000 KWH	150 KW 45,000 KWH	500 KW 150,000 KWH	1000 KW 400,000 KWH	2000 KW 800.000 KWH
FP&L	$1,352	$3,542	$11,556	$28,036	$55,846
TE	$1,376	$3,499	$11,565	$28,425	$56,595
PEF	$1,033	$2,820	$9,377	$23,837	$47,663

Source: Statistics of the Florida Electric Utility Industry 2003 (FPSC)

PEF's typical bills compare very favorably with the two other Peninsular Florida IOUs. In fact, PEF's typical bills average about 20% less across these five use levels than the other two peninsular Florida IOUs.

Q. Would it be appropriate to include other non-IOUs located in peninsular Florida in such a comparison?

A. Yes. It would be appropriate to include the Florida Municipals and Customer Owned Utilities that also operate in Peninsular Florida. However, there are some differences between the municipals and cooperatives that give those entities a cost advantage. For example PEF pays income taxes and property taxes, which the municipals and cooperatives typically don't pay, or at least they pay less. PEF also does not typically have access to lower cost municipal financing or the federally assisted financing that is available to cooperatives. Even with these disadvantages, PEF's prices *still* compare favorably to these other Peninsular Florida utilities.

Q. How does PEF compare with Municipal and Cooperative Electric Utilities in Florida?

A. The FPSC also publishes residential prices and commercial/industrial prices for municipal and cooperative utilities in Florida as I explained above. These are not quite directly comparable to the prices published for PEF because the municipal and cooperative utility prices do not have the local taxes, franchise fees, and gross receipts taxes that are embedded in PEF's rates. Table 3 shows the residential service rates for Florida municipal utilities. Table 4 shows the residential service rates for Florida cooperative utilities. PEF compares quite favorably with these other peninsular utilities, which many recognize have built-in cost advantages not available to IOUs such as PEF.

Table 3
Price of Residential Service
31-Dec-03

Municipal Utility	Minimum Bill	100 KWH	250 KWH	500 KWH	750 KWH	1000 KWH	1500 KWH
Alachua	$8.00	$16.98	$30.45	$52.90	$75.35	$97.80	$142.70
Bartow	$6.60	$15.20	$28.08	$49.58	$71.06	$92.54	$135.52
Blountstown	$3.50	$10.02	$19.80	$36.09	$52.39	$68.68	$101.27
Bushnell	$6.95	$15.70	$28.81	$50.68	$72.54	$94.40	$138.13
Chattahoochee	$4.50	$12.52	$24.55	$44.60	$64.65	$84.70	$124.80
Clewiston	$6.50	$15.29	$28.48	$50.45	$72.42	$94.39	$138.34
Fort Meade	$12.96	$22.70	$37.32	$61.66	$86.02	$110.36	$159.06
Fort Pierce	$5.35	$14.34	$27.81	$50.28	$72.73	$95.19	$140.12
Gainesville	$4.66	$11.87	$22.69	$40.73	$58.76	$79.20	$120.08
Green Cove Springs	$6.00	$15.35	$29.37	$52.75	$76.12	$99.49	$146.24
Havana	$6.00	$15.73	$30.33	$54.65	$78.98	$103.30	$151.95
Homestead	$5.50	$14.45	$27.87	$50.23	$72.60	$94.96	$139.69
Jacksonville	$5.50	$11.77	$21.17	$36.83	$52.49	$68.15	$99.48
Jacksonville Beach	$4.50	$13.54	$27.09	$49.69	$72.28	$94.87	$140.06
Key West	$6.00	$16.22	$31.56	$57.10	$82.66	$108.20	$159.30
Kissimmee	$5.40	$13.97	$26.83	$48.25	$69.67	$91.09	$133.94
Lake Worth	$7.42	$16.44	$29.98	$52.54	$75.10	$97.66	$142.78
Lakeland	$6.35	$15.21	$28.49	$50.63	$72.77	$94.91	$94.56
Leesburg	$8.00	$16.09	$28.22	$48.44	$68.65	$88.87	$129.31
Moore Haven	$8.50	$16.77	$29.18	$49.85	$70.53	$91.20	$132.55
Mount Dora	$4.94	$13.15	$25.47	$46.00	$66.52	$87.05	$128.11
New Smyrna Beach	$5.65	$14.11	$26.80	$47.97	$69.12	$90.27	$132.59
Newberry	$7.50	$16.24	$29.36	$51.22	$73.08	$94.93	$138.65
Ocala	$7.00	$15.35	$27.89	$48.79	$69.68	$90.57	$132.36
Orlando	$7.00	$14.37	$25.43	$43.85	$62.28	$80.70	$122.55
Quincy	$6.00	$15.14	$28.86	$51.71	$74.57	$97.42	$143.13
Reedy Beach	$2.85	$10.70	$22.48	$42.11	$61.74	$81.36	$120.62
Starke	$6.45	$15.06	$27.98	$49.50	$71.03	$92.55	$146.60
St. Cloud	$7.32	$15.02	$26.58	$45.83	$65.09	$84.34	$128.08
Tallahassee	$4.94	$14.87	$29.75	$54.57	$79.37	$104.18	$153.81
Vero Beach	$7.00	$15.72	$28.81	$50.60	$72.41	$94.20	$137.80
Wauchula	$8.62	$18.59	$33.54	$58.46	$83.38	$108.30	$158.14
Williston	$8.00	$17.64	$32.11	$56.22	$80.33	$104.44	$152.66
PEF*	$8.03	$15.39	$26.43	$44.84	$63.23	$81.62	$123.43

*PEF added for comparative purposes

Source: Statistics of the Florida Electric Utility Industry 2003 (FPSC)

Table 4 Price of Residential Service 31-Dec-03							
Cooperative Utility	**Minimum Bill**	**100 KWH**	**250 KWH**	**500 KWH**	**750 KWH**	**1000 KWH**	**1500 KWH**
Central Florida	$8.50	$16.32	$28.07	$47.62	$67.19	$86.75	$125.87
Choctawhatchee	$18.00	$25.15	$35.87	$53.74	$71.61	$89.48	$125.22
Clay	$9.00	$15.92	$26.30	$43.60	$60.91	$78.20	$117.80
Escambia River	$9.00	$17.10	$29.25	$49.50	$69.75	$90.00	$130.50
Florida Keys	$7.00	$15.73	$28.84	$50.67	$72.51	$94.34	$138.01
Glades	$10.50	$18.80	$31.25	$52.00	$72.75	$93.50	$135.00
Gulf Coast	$10.00	$17.81	$29.53	$49.05	$68.58	$88.10	$127.15
Lee County	$5.00	$12.91	$24.78	$44.55	$64.33	$84.10	$123.65
Okefenoke	$10.00	$17.29	$28.22	$46.44	$64.67	$82.89	$119.33
Peace River	$10.50	$19.34	$32.60	$54.70	$76.80	$98.90	$143.10
Sumter	$8.25	$16.37	$28.55	$48.85	$69.15	$89.45	$130.05
Suwannee Valley	$8.73	$16.42	$27.96	$47.20	$66.43	$85.66	$124.13
Talquin	$8.00	$15.60	$27.00	$46.00	$65.00	$84.00	$122.00
Tri-County	$10.00	$18.60	$31.50	$53.00	$74.50	$96.00	$139.00
West Florida	$8.00	$16.53	$29.31	$50.63	$71.94	$93.25	$135.88
Withlacoochee River	$9.75	$17.51	$29.15	$48.55	$67.94	$87.34	$126.14
PEF*	$8.03	$15.39	$26.43	$44.84	$63.23	$81.62	$123.43
*PEF added for comparative purposes							
Source: Statistics of the Florida Electric Utility Industry 2003 (FPSC)							

Q. Did you compare the PEF's commercial and industrial prices to those of municipal and cooperative utilities in peninsular Florida?

A. Yes. The results are shown in Tables 5 and 6, respectively for the municipal utilities and the cooperative utilities. PEF again compares very favorably, with commercial and industrial prices significantly lower than those offered by the municipal utilities, with the exception of Jacksonville, which has slightly lower prices. PEF also has lower prices that the vast majority of the cooperatives for most categories.

Table 5					
Price of Commercial and Industrial Service					
31-Dec-03					
Municipal	75 KW	150 KW	500 KW	1,000 KW	2,000KW
Utility	15,000 KWH	45,000 KWH	150,000 KWH	400,000 KWH	800,000 KWH
Alachua	$1,483	$3,957	$13,138	$33,013	$66,003
Bartow	$1,647	$4,283	$14,234	$35,177	$70,335
Blountstown	$1,102	$3,292	$10,959	$29,211	$58,415
Bushnell	$1,616	$4,281	$14,221	$35,553	$71,085
Chattahoochee	$1,321	$4,052	$13,505	$34,340	$68,680
Clewiston	$1,548	$4,305	$14,269	$36,791	$73,547
Fort Meade	$1,746	$4,792	$15,765	$38,750	$77,410
Fort Pierce	$1,451	$3,833	$12,695	$31,795	$63,555
Gainesville	$1,197	$3,128	$10,391	$25,111	$50,161
Green Cove Springs	$1,637	$4,337	$14,399	$30,123	$60,120
Havana	$1,466	$4,385	$14,601	$38,926	$77,846
Homestead	$1,625	$4,337	$14,374	$36,188	$72,341
Jacksonville	$1,016	$2,551	$8,385	$20,450	$40,700
Jacksonville Beach	$1,795	$4,714	$15,677	$38,944	$77,872
Key West	$1,744	$4,712	$15,644	$39,589	$79,159
Kissimmee	$1,473	$3,677	$12,498	$29,371	$58,687
Lake Worth	$1,881	$4,867	$16,106	$39,866	$79,682
Lakeland	$1,363	$3,658	$12,833	$31,178	$61,980
Leesburg	$1,343	$3,469	$11,523	$28,365	$56,713
Moore Haven	$1,544	$3,969	$13,160	$32,360	$64,690
Mount Dora	$1,153	$3,060	$10,166	$25,439	$50,863
New Smyrna Beach	$1,471	$3,934	$13,036	$32,874	$65,714
Newberry	$1,593	$4,000	$13,300	$32,107	$64,199
Ocala	$1,299	$3,409	$11,315	$28,155	$56,289
Orlando	$1,171	$2,995	$9,949	$24,227	$48,551
Quincy	$1,235	$3,305	$10,876	$27,688	$54,228
Reedy Beach	$1,426	$3,585	$11,904	$28,804	$57,588
Starke	$1,608	$4,806	$15,999	$42,649	$85,289
St. Cloud	$1,223	$3,129	$10,395	$25,374	$50,732
Tallahassee	$1,587	$4,137	$13,636	$33,878	$67,716
Vero Beach	$1,392	$3,827	$12,654	$32,429	$64,789
Wauchula	$1,537	$4,885	$16,132	$41,067	$82,069
Williston	$1,609	$4,401	$14,390	$36,290	$72,530
PEF*	$1,033	$2,820	$9,377	$23,837	$47,663
*PEF added for comparative purposes					
Source: Statistics of the Florida Electric Utility Industry 2003 (FPSC)					

Table 6					
Price of Commercial and Industrial Service					
31-Dec-03					
Cooperative Utility	**75 KW 15,000 KWH**	**150 KW 45,000 KWH**	**500 KW 150,000 KWH**	**1,000 KW 400,000 KW**	**2,000 KW 800,000 KWH**
Central Florida	$1,389	$3,519	$11,613	$28,050	$56,050
Choctawhatchee	$1,148	$2,924	$9,035	$22,407	$44,784
Clay	$1,142	$3,027	$9,960	$25,185	$48,710
Escambia River	$1,480	$3,910	$12,940	$32,440	$64,840
Florida Keys	$1,112	$3,234	$10,902	$28,242	$56,536
Glades	$1,586	$4,418	$14,125	$22,895	$45,615
Gulf Coast	$1,191	$3,249	$10,802	$27,452	$54,892
Lee County	$1,187	$3,155	$11,055	$26,855	$53,695
Okefenoke	$1,231	$3,020	$9,833	$23,956	$47,811
Peace River	$1,279	$3,293	$10,860	$26,910	$53,770
Sumter	$1,184	$3,040	$10,015	$24,790	$49,530
Suwannee Valley	$1,410	$3,687	$9,346	$22,053	$44,065
Talquin	$1,156	$3,103	$10,530	$23,480	$46,660
Tri-County	$1,360	$3,325	$10,850	$26,300	$52,500
West Florida	$1,264	$3,242	$10,690	$23,070	$46,040
Withlacoochee River	$1,182	$3,086	$10,228	$25,401	$50,777
PEF	$1,033	$2,820	$9,377	$23,837	$47,663
*PEF added for comparative purposes					
Source: Statistics of the Florida Electric Utility Industry 2003 (FPSC)					

Q. The panel composed of Mr. Mike Culver and Mr. Charlie Martin, at page 3 of their testimony, compares PEF's commercial rates to those of other IOUs in the Southeast. Please comment.

A. The "analysis" presented by Mr. Culver and Mr. Martin suffers from the same analytic failures and introduces the same omitted variable bias as Mr. Brubaker. It is simply not relevant to compare PEF to a set of utilities that do not face the same load characteristics, transmission constraints, and transportation costs that PEF faces. Mssrs. Martin and Culver find great significance in the fact that PEF's fuel costs are higher than Georgia Power's fuel costs. However, much of the differential is due to location, plant mix, purchasing power, and customer make-up. Located in the Florida Peninsula, PEF lacks the ready access to cheap coal that Georgia Power enjoys. Environmental considerations are also different in

Florida. It is, therefore, not surprising that Georgia Power has lower fuel costs than PEF.

The relevant question is the one that the Translog model has addressed in this proceeding; to wit: how has PEF performed relative to how a typical efficient utility with PEF's characteristics would have been expected to perform based upon utility performance across the U.S. and over nine years. And the answer to that most relevant question in this proceeding is that PEF's Total Costs were 12.7% below what would have been expected. This saves PEF's customers about $400 million per year. The analysis of prices offered by Mssrs. Culver and Martin and Mr. Brubaker do nothing to alter this undeniable truth. PEF has performed very well given its business and operating circumstances. Just limiting the comparison of prices to peninsular Florida also shows a similar result. PEF is a good utility and high performer. In fact, no witness has challenged the results of the Translog statistical benchmarking analysis.

III. RECOGNIZING SUPERIOR PERFORMANCE IN THE FORM OF A HIGHER ROE IS GOOD REGULATORY POLICY.

Q. Why is this discussion of increasing PEF's authorized ROE to recognize superior performance important?

A. PEF is a growing utility that has performed well for its customers. As I explained in my Direct Testimony, there is precedent and many reasons to increase PEF's ROE over that Dr. Vander Weide determined, bringing PEF's ROE to 12.8%.

In this proceeding, Intervenors seek a rollback in PEF's revenue requirements, not the rate relief that PEF seeks, needs, and deserves. In contrast, I urge the Commission to consider both PEF's minimum "needs," as well as PEF's superior performance rationale when it sets PEF's authorized ROE and subsequent revenue requirements and tariffs.

Q. At pages 98-100 of his Direct Testimony, Mr. Rothschild criticizes your recommended upward adjustment to PEF's ROE for superior performance. Please respond to his critique.

A. Mr. Rothschild argues that an upward adjustment for superior performance is "inappropriate, unnecessary, and more than likely would be counterproductive, in that it would provide inappropriate incentives to PEF." Mr. Rothschild apparently thinks that the benefits associated with regulatory lag, where a utility supposedly "keeps" cost savings until rates are reset at the next rate hearing, provides all the incentive that is necessary. And if this "carrot" was not incentive enough, Mr. Rothschild argues that the Commission carries a big stick in the way of prudence disallowances, which provides further incentives for the utility to strive to keep costs down. Presumably, this logic also dictates that Mr. Rothschild is opposed to any type of performance based or revenue sharing ratemaking. I find this all to be quite perplexing because regulation is far less about punishment and discipline and much more about incentives and opportunities.

Regardless, Mr. Rothschild's first conclusion is not relevant for PEF. He falsely implies that PEF "sits on its hands" between rate cases and basks in and captures returns for shareholders when more cash comes in than had been expected when rates were set initially. This is a naïve and decidedly incorrect depiction of PEF's performance.

PEF does not restrict its spending and investments to the cost-of-service analyses in the last rate case. PEF uses incremental revenue and income to pay for necessary and efficiency improving incremental costs. The Commission monitors PEF's between-rate-case activities through its monthly surveillance reports. PEF neither seeks to keep all nor accepts every last dollar of any upside income between rate cases as Mr. Rothschild's narrow consideration of regulatory lag implies it would attempt to do. PEF uses this so-called regulatory lag dividend to help its customers, add necessary inputs, make additional hook-ups, and improve efficiency.

The fact is that, as I have explained, PEF's total cost record outperforms reasonable and efficient expectations based upon the Total Cost estimates for the electric industry. This means that PEF should receive the proposed upward adjustment in its ROE. The fact that PEF has been a superior performer also means that PEF should <u>not</u> be penalized for using its ingenuity and enterprise between rate cases to beat expectations and to better serve and benefit its customers.

This Commission has recognized that what is good for PEF can often also be good for ratepayers (*i.e.,* revenue sharing). If PEF is provided with additional incentives, rather than penalties, to keep costs down in the future, PEF is more likely to strive harder to attain those harder to achieve cost savings. This incentive can take many forms, including regulatory adjustments to ROE if it performs in a demonstrably superior manner, as is the case here. I believe strongly that innovation and enterprise are more likely when positive incentives, not after-the-fact disallowances, are used to encourage superior performance.

As I discussed in my Direct Testimony, this Commission has used this positive incentive approach in the past. Most recently in 2002, the Commission adjusted Gulf Power's ROE upward for superior performance. And for symmetry, the Commission has also penalized a utility by reducing its ROE when its performance lagged. This is similar to the approach I championed when I was head of the Public Service Commission of Wisconsin. I believe it was effective then. It can be equally effective now.

Q. What is Mr. Rothschild's basis for asserting that an upward adjustment to PEF's ROE would be counterproductive?

A. I don't know because he never explains what he means. It is hard to imagine why a utility would not have an incentive to make improvements and to keep cutting costs between rate cases when it expects it likely would be rewarded in the next rate case if it does, and can be penalized through a disallowance of an adder if it fails. Mr. Rothschild asserts that with a higher return on capital, it will be more difficult for PEF to "justify making incremental investments that might be designed to reduce expenses." This is not logical or reasonable. Does he mean that only the needy strive to achieve? I assume this is what he means by counterproductive. Mr. Rothschild seemingly fails to consider relevant those circumstances where successful people or businesses eschew failure and constantly strive to work to keep their advantage. Common sense dictates that if the utility knows that it will be rewarded for superior performance and may be punished for lackluster performance, it would have the incentive to achieve all possible savings. Regardless, PEF's performance has been stellar. I would reinforce this behavior and certainly would not, as some suggest, punish PEF in this rate case.

Q. Mr. Rothschild argues that providing an incentive in the form of an upward adjustment to PEF's ROE would not provide an incentive to work harder to achieve future productivity gains. Do you agree with him?

A. Absolutely not. Mr. Rothschild's argument is premised on the faulty assumption that the "bonus" as he describes it, would go to shareholders, but that it is the employees who implement the cost savings, and those employees are paid by the ratepayers. His logic seems to be that because the employees would not get any additional money, they will not work harder to implement the cost savings. This thinking is wrong-headed on several levels. First, employee salaries are paid by the utility, not by ratepayers. Second, employees who wish to remain employed and advance within the company have various direct and indirect incentives to implement PEF's strategic and business plans. High performing employees, if not compensated reasonably, could also leave the business that fails to value their efforts. That is how all companies function.

Second, the facts belie his assumption. PEF has shown for more than two decades that it uses funds between rate cases to make improvements and to serve its customers. Moreover, PEF has been shown to be a superior performer in a national comparison using the Translog Model and analysis. PEF also has a good record of using employee compensation and training to benefit its workforce.

Mr. Rothschild also argues that to the extent employees are paid bonuses for good performance, ratepayers also pay for this. This is misleading. Mr. Rothschild concludes that a bonus paid to investors would be duplicative and "paid to an entity that does not provide any cost savings." It is difficult to untangle Mr. Rothschild's thought process here. On the one hand, he is opposed to providing investors with a bonus because they did not do the work to accomplish the cost savings. He seems to think that capital is not a factor of production. I had thought that the labor theory of value went down the intellectual drain long before the Berlin Wall fell. Mr. Rothschild is seemingly opposed to rewarding employees who perform in an exemplary manner because it's their job. I find all this to be nonsensical. There is a role for both efficiency and incentives. If a utility knows there is a reward for exemplary service, its management will redouble its effort to do everything possible to achieve that reward. People will lead this charge and apply human capital and financial capital, whichever is the more productive input to get the job done. This is simple human nature and how successful businesses function.

Q. At pages 22-23 of his Direct Testimony, Dr. Porter argues that a "bonus for past performance has little incentive value." Please respond to Dr. Porter's assertion.

A. Dr. Porter's assertion is, apparently, based on the premise that a Commission in the future is not bound to follow the precedent set by a prior Commission. Thus, Dr. Porter reasons that unless there is reason to assume that the Commission will have the same make-up as the Commission that provides the adjustment to ROE, there is no reason to think that the new Commission will also provide the reward. Therefore, there is no incentive. This is hopelessly flawed reasoning. While there is no guarantee that future Commissions will follow the same path as a current Commission, it is my experience that if it "ain't" broken, a new Commission is not likely to "fix" it and tinker with a winning and successful formula. This has often been the situation in Florida, where there has historically been stable and reasonable cost-of-service regulation.

Cost-of-service regulation, by necessity, uses a snapshot of data and assumptions to fix tariffs for a period of time. This is the reality of traditional regulation. In this context, measuring past and current efforts are the only real data available to set future prices.

Monitoring between rate cases is another helpful tool used in Florida. At the next rate case, performance should be and is measured. When there has been superior performance, I believe strongly there should be recognition and, going forward, the adjustment to ROE. At a minimum, there should be no penalty or failure to recognize what has been outstanding efforts. PEF should be recognized for a job well done, and this should carry on into the future, where the monitoring and future reward cycle of regulation would reasonably, albeit with no guarantee, repeat.

Q. Dr. Porter argues, at page 23 of his Direct Testimony, that regulatory markets are designed to mimic competitive markets, and that perpetuating profits (by giving an adjustment to authorized ROE) ignores competitive processes. How do you respond to this assertion?

A. I concur with Dr. Porter to a point. Regulation can never fully implement the discipline and rewards of a competitive market. Dr. Porter equates regulatory lag to a competitive firm's short-run profits when it successfully innovates. He fails to address how utilities, such as PEF, use such "income" to spend money to meet customer needs between rate cases, particularly in high growth periods. Providing an additional incentive to reward exemplary performance provides additional incentives for the utility to continue to innovate, to continue to capture cost savings between rate cases that will inure to the benefit of customers in the long run. Competitive firms have these incentives in the market. As this Commission has recognized, what is good for the utility is, by extension, good for ratepayers in the long run. Dr. Porter forgets this regulatory dynamic in his zealous efforts to denigrate the regulatory process with a false comparison to the competitive market. Further, the ROE is not being granted in perpetuity. The Commission will revisit it at PEF's next rate case.

Q. Dr. Porter finds it unlikely that customers will benefit from the upward adjustment to ROE. Do you disagree?

A. I do disagree with Dr. Porter. First, customers have been benefiting from PEF's superior performance of beating the industry, other things equal, with a 12.7% per year cost savings. Second, customers will also continue to benefit if PEF is provided with the ROE adjustment I propose to both recognize superior past performance and provide a new incentive to continue to cut costs and develop new, innovative ways to do so. When shareholder, management, employee, and customer interests are aligned, as PEF has done and seeks Commission support to continue, it will be a win for Florida consumers and PEF's customers.

Q. At page 3 of his Direct Testimony, Mr. Chalfant asserts that it is not reasonable for PEF to request a reward for past performance. Do you concur?

A. No. As I set forth in my Direct Testimony, the ROE adjustment I propose will provide an incentive for PEF to continue its cost cutting efforts, which recognized superior performance and would provide ongoing incentives for achieving additional benefits to customers.

Q. Mr. Chalfant asserts that PEF had done no more than the minimum required, as evidenced by the fact that his associate Mr. Brubaker asserts that PEF has some of the highest rates in the region. How do you respond to that assertion.

A. Both Mr. Chalfant and Mr. Brubaker are wrong. In Section 2, I explained why Mr. Brubaker's comparison of PEF's prices to others throughout the Southeast region is flawed and biased because it omits relevant variables. I will not repeat those arguments here. Mr. Chalfant's reliance on Mr. Brubaker's analysis omits the same causal relevant factors and he introduces no credible evidence to back up his assertion that PEF has not performed in an exemplary manner. I again point to PEF's relative price performance compared to other utilities in the Florida peninsula.

Q. At page 4 of his Direct Testimony, Mr. Chalfant asserts that PEF is attempting to extract monopoly rents from its customers through the requested ROE adjustment. How do you respond to this allegation?

A. Mr. Chalfant is mistaken. PEF has no monopoly power. This Commission sets PEF's prices, investment, cost-of-service, and other important policies in a fair and balanced manner. PEF can not increase its profits by selling less and charging more. PEF is requesting an ROE, including the upward adjustment that I have recommended, which is below the ROE PEF is currently earning. PEF is proposing to reduce its current ROE. This is hardly an attempt to extract what Mr. Chalfant describes as monopoly rents. Indeed, the 12.8% ROE proposed would help PEF to continue to grow, add customers, to improve efficiency, and to perform in an exemplary and superior manner.

Q. Mr. Chalfant asserts that because a competitive market provides one-time incentives and rewards, that regulation should do the same. Please respond.

A. PEF is requesting, and I am proposing, the upward ROE adjustment both to recognize its past exemplary service, and as an incentive to continue to achieve even additional savings for its customers. The requested ROE is neither perpetual nor permanent. PEF realizes that unless it continues to provide excellent service and succeeds to continue to control and reduce costs, it may not be rewarded in the future. This is no different than a competitive firm with a good year that seeks to continue to succeed in the future. In fact, this Commission has also penalized poorly performing utilities with a reduced ROE. Thus, I conclude that the adjustment is quite similar to rewards offered in a competitive market to innovating firms. There is no guarantee of future success unless the business continues to work hard, as PEF will likely try to do.

Q. At page 6 of his Direct Testimony, Mr. Chalfant states that underlying your position is the "disturbing concept that PEF is entitled to all the profits that it can achieve." Does this concept underlie your support of PEF's adjustment to ROE?

A. No. I am not even sure what Mr. Chalfant is saying. If he is saying that I think PEF should be able to price its products as if it were an unregulated monopolist, I certainly would disagree. Under the regulatory regime in which PEF operates, it is entitled to a reasonable opportunity to earn its authorized rate of return. This is the underlying premise of regulation. There is nothing in my recommendation that changes this. I am certainly not proposing that PEF be entitled to, as Mr. Chalfant so colorfully describes it, extract "maximum profit from its customers." Mr. Chalfant needs to be reminded that PEF negotiated a settlement with an annual $125 million revenue reduction savings for the past four years and is now proposing to reduce the authorized ROE to 12.8%, which is less than it is currently earning. This is hardly what I would describe as extracting maximum profit out of its customers.

Mr. Chalfant also argues that under cost-based regulation, PEF has reaped the benefits of its cost cutting by keeping the savings during the time period between rate cases (regulatory lag) and that this provides PEF with all the incentive it needs. As I have explained, utilities, like any business, typically use their cost savings to offset other costs that may be increasing prior to when they, or their regulators, increase retail prices to consumers. The trouble with Mr. Chalfant's concept of regulation is that he thinks that regulatory lag should provide the utility with all the upside it needs. The problem with Mr. Chalfant's view of the world is that, as he states at page 7 of his Direct Testimony, he wants to keep the period of regulatory lag where the utility would keep the costs savings to a "minimum" and would request that the Commission require "new rate proceedings whenever earnings exceed the allowed level..." This concept of many rate cases, even one a year, is not necessarily good regulation. Instead, periodic rate reviews with sensible incentives is often, as it is here, far superior. Draconian ratemaking such as suggested by Mr. Chalfant would, in my opinion, destroy much of the incentive that a utility would have to innovate and save costs because as soon as it did so and its earnings exceeded its authorized ROE, Mr. Chalfant would support dragging it in to reset its ROE. This may be good for outside consultants. Nevertheless, I think that some sort of sharing method, whether it is a formal performance based or revenue sharing or one such as the ROE adjustment I recommend here provides much superior incentives to a utility to work over several years to perform well and cut costs.

Q. How do you respond to Mr. Chalfant's argument at page 6 of his Direct Testimony that PEF has simply met its side of the 2002 rate case settlement and that no more is required?

A. If PEF had simply met the goals established by the 2002 rate case settlement agreement, I might be more inclined to agree with Mr. Chalfant. But this is not the case. As Mr. Habermeyer testified in his Direct Testimony, PEF has exceeded the goals established in the 2002 rate settlement agreement. This is demonstrated further in Mr. Lyash's Direct Testimony by the extent to which PEF has improved service quality and reliability. Further, my own benchmarking shows that PEF's total costs are about $400 million per year less than what I would expect Total Costs to be for a similarly situated, efficient utility. This is performance that is superior, by any definition of the term superior, and warrants both current recognition and continued incentives in this proceeding.

Q. Mr. Chalfant at page 8 of his Direct Testimony asserts that you are opposed to passing cost saving benefits to customers. Please respond to his assertion.

A. Mr. Chalfant has totally misread my Direct Testimony and he ignores what PEF has done. I do support passing on cost savings benefits to customers. In fact, PEF has done just this by offsetting on-going cost increases since the last rate case as shown in PEF's Surveillance Reports and MFRs, and passing on $125 million annually in rate reductions under the 2002 rate case settlement agreement. There are many reasons, including hard work and success, why PEF has had such infrequent needs to increase its base rates. Since 2002, PEF explicitly has shared past savings with customers, and will continue to do so It is Mr. Chalfant who is greedy in my view. He wants to severely limit PEF's ability to share in the fruits of its efforts, instead he prefers to limit severely any regulatory lag, perhaps using annual rate cases to do so, eschew any formal incentive or sharing plan, and reward PEF with a rate rollback when it requires rate relief.

Q. Mr. Chalfant at page 8 of his Direct Testimony asserts that your proposal to add 50 basis points to PEF's ROE for superior performance lacks a "symmetric set of rewards/penalties." Do you disagree?

A. Yes. There is symmetry inherent in my proposal. Only superior performance would achieve the upward adjustment to ROE. Unless success repeats, the upward adjustment would be lost. The actions this Commission has taken in the past, where it has penalized utilities by reducing the authorized ROE for poor performance is an additional symmetric response.

Q. At pages 9-11 of his Direct Testimony, Mr. Chalfant dismisses your efforts in Wisconsin as not being "similar to what Dr. Cicchetti is proposing here." How do you respond?

A. Mr. Chalfant is setting up a straw person to knock down. Of course, the situation in Wisconsin about twenty-five years ago was different than the situation in Florida today. But the principle was the same: reward utilities that perform well, innovate, and cooperate with regulatory authorities with an upward adjustment to their ROEs. In my concurring opinion I stated that "...utilities which, either by managerial decision or regulatory obligation, achieve certain established targets benefiting the people of Wisconsin, should receive higher rates of return. Meanwhile, those utilities that do not perform as well will receive lower rates of return."[4] Perhaps the language in the Orders is not as explicit as Mr. Chalfant would like. However, I will remind Mr. Chalfant that I was there. I participated in the hearings and held discussions in open meetings with the Intervenors and utilities where I let my position be well known. My stated and well-known intent in Wisconsin was to provide positive, as well as negative, incentives in the form of adjustments to ROE for utilities to provide superior performance, and penalize laggards. I knew then, as this Commission realizes today, that keeping the utility healthy and adding properly incented benefits means that the customers will benefit. Mr. Chalfant's concept that this Commission should haul in PEF as soon as its earnings exceed its authorized ROE, no matter the reason, and yank away all excess earnings for the customers is short-sighted, wrong-headed, and directly

[4] *Application of Wisconsin Electric Power Company for Authority to Increase its Electric Rates*, 1979 Wisc. PUC LEXIS 45, (March 6, 1979).

inconsistent with recent Commission precedent. Mr. Chalfant wants to constantly reset and restart the game. This would be costly and, I believe, would not work as well as reasonable incentives in the form of rewards for superior performance.

Q. Mr. Gorman, at page 35 of his Direct Testimony asserts that your basis for rewarding PEF with an upward adjustment to its ROE for superior performance is "that it has not increased 'base prices' since 1993" and that you have ignored "important external factors that have played a significant role in reducing PEF's cost of service…" Please respond to Mr. Gorman's assertions.

A. Mr. Gorman focused on only the third reason I provided at pages 39 and 40 of my Direct Testimony, and even then he misinterpreted that. In my Direct Testimony I supported a 12.8% ROE because (1) consumers benefit when utilities are financially healthy; (2) other jurisdictions are encouraging sharing productivity benefits and consumers are benefiting; (3) there has been no rate increase since 1993 and in fact, over the past four years customers have received an annual $125 million rate decrease for these base rates; and (4) PEF is adding to its rate base, its dismantlement expenses have increased, and it needs to replenish its storm reserve. In short, PEF has capital needs and deserves rate relief, coupled with a modest upward ROE adjustment to keep it strong and highly motivated to continue to serve customers in an exemplary manner. Rewards and incentives are the American way. These are the grist that keeps our economy humming and the best in the world. I have no doubt that consumer benefits will easily trump the added cost.

Q. What about the external factors touted by Mr. Gorman?

A. Mr. Gorman asserts that these external factors, primarily the reduction in capital costs, is largely responsible for avoiding rate increases and is beyond management's control. I disagree with Mr. Gorman's assertion. First, Mr. Gorman's mischaracterization of my testimony permits him to focus on only the lack of a rate increase since 1993. I explained above why this was but one factor in support of my support for PEF's requested 12.8% ROE. I also have explained that the same debt reductions apply to all 95 utilities in the Translog Model and PEF still outperformed the expected efficient utility estimate of Total Cost by 12.7%. Specifically, the Translog model shows that PEF has performed in a superior fashion with respect to reducing all inputs but fuel and purchased power, not just those associated with capital. Second, in order to avail itself of the reduced capital expenses, PEF had to achieve a certain level of financial stability. This does not happen by itself. PEF management accomplished this and needs rate relief to complete the job.

Third, I showed in my Direct Testimony that over five years (2002 to projected 2006), PEF's O&M expenses are up 5.64%, which is: (1) less than the CPI (inflation) of 7.34%; (2) less than customer growth of 8.67%; and (3) less than the increase in MWHs sold of 8.73%. In fact, these factors would, in some fashion, be additive to each other. PEF's operating expense performance is simply very exceptional.

It is irresponsible for Mr. Gorman to imply that the savings associated with reduced finance costs would have happened regardless of how PEF was being operated. Mr. Gorman's assertion that avoided rate increases were due to merger savings and "not the result of superior management performance, but rather were created by the effect of the merger" is also patently absurd. Who does Mr. Gorman think was responsible for accomplishing the merger, for implementing the merger, and overseeing that the promised benefits were not only achieved, but exceeded? The answer, of course, is that these benefits, and using proceeds earned during rate cases to pay for customer growth, inflation, sales, growth, etc., is what PEF has done. PEF has a superior outcome as a direct result of management efforts, not the efforts of elves in the night.[5]

Q. Mr. Stephen Stewart testifies at page 9 of his Direct Testimony that AARP's position is that the Commission should deny PEF's request for an upward ROE adjustment. Please respond to his statement.

A. Mr. Stewart prefaces his testimony with the admission that he does not consider himself to be an expert on return on equity issues and that he is not offering an opinion as to the required ROE. Rather, at page 9, he offers AARP's opinion, even though that organization is also not an expert in these matters. Nevertheless, their "position" warrants a response.

[5] With all due respect to the Brothers Grimm.

Mr. Stewart observes that PEF has received an incentive for its past performance through its revenue sharing plan. This is true. But that plan is coming to an end. My proposal replaces the incentives provided under revenue sharing with new revenue requirements with a new incentive. If PEF continues to perform in a superior manner, future Commissions can determine the appropriate ROE.

Mr. Stewart avers that the Commission's "traditional equity awards are more than adequate to compensate the utility's shareholders, especially given the continuing reduction of risks they are exposed to." Mr. Stewart explains that "a very large percentage of their revenues are subject to 100 percent cost recovery through rates." Whether traditional equity awards are "adequate" is somewhat beside the point. I consider them typically to be the floor or a starting point because this is the *quid pro quo* for providing safe and reliable service. I propose that the Commission offer something more to reward PEF for superior performance and to provide incentives to PEF to maintain this high level of performance and cost cutting, efforts that will strengthen the utility and benefit the customer, a truly symbiotic relationship.

In addition, the pass-through of certain costs is always the subject of a prudence review in which there can be and often are disallowances of full recovery. Furthermore, some regulatory authorities like to mix pass-through mechanisms with cost-of-service regulation in order to focus their regulatory scrutiny on the parts of cost-of-service they deem the utility is best able to affect or control. In this combined fashion, regulators seek the greatest "bang" for their regulatory "buck" because their efforts focus on things that are more amenable to incentives, performance, and scrutiny to alter outcomes. Further, PEF does not get the immediate recovery of its expenses. The storm expenses incurred in October 2004 offer a good example. The Company will not fully receive recovery of its allowed costs (only about 90% of its total storm-related costs) until 2007.

Mr. Stewart also fails to describe fully the risk faced by shareholders under various pass-throughs. Many of these are not fully automatic, but are subject to prudence review by the Commission, which often reduces the amount of dollars recovered. In the recent storm docket case, the Commission did not allow all costs that PEF sought to be passed through in a surcharge. The allowed cost recovery was about 10% lower than the costs that PEF claimed. I do not wish to reopen the nuances of that case here. Regardless, Mr. Stewart is mistaken when he thinks that there is a guarantee of full recovery. Therefore, there is risk to shareholders associated with approval and prudence hearings.

Q. At page 22 of her Direct Testimony, Ms. Sheree Brown argues that PEF's actions have not yielded $125 million in annual benefits to customers. Is this true?

A. No, it is not true. The inescapable truth is that for the past five years, PEF's customers have enjoyed base rates that reflect $125 million per year in reduced revenue requirements that were reached in the 2002 Settlement. That is the fact, notwithstanding Ms. Brown's assertion that these reductions were cost deferrals, not savings. The fact is that customers have paid $125 million per year less since 2002 than the base rates that they had been paying and which were lower still than PEF's then cost-of-service filing would have supported. If PEF failed to perform, its shareholders would have paid for these reductions. Regardless, the customers benefited and PEF performed in a superior fashion.

Q. Does Ms. Brown dispute the fact that PEF has successfully reduced operating expenses?

A. No, she readily admits that "the Company has successfully reduced certain operating expenses." This is supported by the testimony submitted by various Company witnesses and buttressed by my own benchmarking analysis.

Q. At page 23 of her Direct Testimony, Ms. Brown claims that the $45.9 million in revenue sharing benefits received by PEF's customers is not attributable to PEF's cost-cutting efforts. Do you agree?

A. Ms. Brown misrepresents what I said. I never stated in my testimony that the revenue sharing benefits were attributable to PEF's cost cutting efforts. The revenue sharing plan was part of the 2002 rate case settlement agreement and was separate from the $125 million in rate requirement reductions that were attributable to cost savings

In addition, Ms. Brown asserts that the rewards of PEF's cost cutting efforts have "accrued to shareholders," not customers. Apparently, in Ms. Brown's world, all revenue associated with cost-cutting is earmarked for shareholders while a portion of the revenue associated with customer growth and weather goes to customers through revenue sharing. Alas, in the real world, there is no such differentiation of the revenue stream and Ms. Brown cannot credibly make this argument. Ms. Brown ignores PEF's enviable record of holding base rates below inflation for twenty plus years, with no increases since 1993 and a reduction in 2002. The cold hard facts are that PEF entered a settlement in 2002 that pledged and provided to its customers both an annual $125 million rate reduction and worked to add an additional $45.9 million in revenue sharing benefits.

Q. At page 23 of her Direct Testimony, Ms. Brown disputes that your proposed ROE adjustment will provide an incentive to PEF to continue its cost cutting efforts. Please respond to her.

A. As I have said repeatedly, good regulation both recognizes good performance and provides incentives for utilities to continue cost cutting efforts. The ROE adjustment will provide such recognition, plus an incentive. This means that PEF will want to do everything it can to ensure that it will continue to receive this type of performance recognition from the Commission in the future, as well as future incentives. In essence, the adjustment replaces the revenue sharing mechanism that is expiring at the end of 2005. Thus, I disagree with Ms. Brown's assertion at page 26 of her Direct Testimony that a proposed 12.8% ROE will not change the directions of utility's incentives.

I have some employees who work under a specific formula for determining their quarterly bonuses. The metrics used are transparent, quantitative, and fairly rigid. I have other employees who I simply award a bonus for superior performance, which I know when I observe their contributions. There are no formulas and no guarantees. I am convinced that both approaches work. At times, I am troubled about potential formula gaming, or working in a fashion to achieve a number under the first approach.

I also worry that I may not always fully recognize the efforts that go into superior performance. I push myself to make certain that I do not take superior performance for granted. In a small but relevant way, what I do in my firm is a useful insight into what I am proposing for PEF. The Commission can adopt formulas, as have other regulators, to reward performance. Alternatively, the Commission can accept my recommendation and add 50 basis points to PEF's ROE. I am fully convinced that PEF will treat such recognition as a strong incentive to maintain and improve its superior performance status and will continue to beat expectations.

Further, the ROE adjustment I proposed will strengthen the company financially, which as this Commission recognized in the storm docket, is essential to providing ongoing and future benefits to PEF's customer. I cannot stress strongly enough my mantra when sitting as a commissioner: "what is good for the utility is good for the customer," especially a utility that is growing and adding infrastructure.

Q. Ms. Brown argues that regulatory lag between rate cases provides the utility all the incentive that is required. Do you agree?

A. No, I do not. This is especially so when there are Intervenors who will reflect Mr. Chalfant's clamoring for a speedy rate hearing as soon as the utility's earnings exceed its authorized ROE, no matter the reason for the increase. And that is precisely the problem that creates disincentives for the utility under cost-of-service regulation with frequent rate cases. I also believe that a utility that uses regulatory lag income to offset costs is quite different than one that simply seeks to enrich shareholders by pushing all gains into ROE during lags, and in the process, forces a new rate case sooner. PEF is not this sort of utility. PEF is a high performer and deserves recognition as such.

Q. At pages 27-28 of her Direct Testimony, Ms. Brown discusses the revenue sharing plan in effect for Georgia Power and attempts to distinguish that plan from the recommended ROE. Please comment.

A. To a certain extent, she is correct. The Georgia Power plan is a formal plan with a clearly established neutral band around a set ROE, and varying sharing allocations when earnings increase above the neutral band or fall below it. Ms. Brown's primary critique of my proposal is that, unlike the Georgia Power plan, the adjustment is one-sided. However, Ms. Brown fails to recognize, as I explained above for my different employee bonus approaches, that at PEF's next rate hearing, the Commission could, as it has done with other utilities in the past, impose a penalty and reduce authorized ROE if PEF fails to meet expectations.

This provides the symmetry along with the others I discussed above that Ms. Brown finds lacking. Thus, I conclude that her concerns are not valid.

Q. Ms. Brown asserts at page 25 of her Direct Testimony that because a large percentage of PEF's total operating costs are covered by cost recovery clauses and adders, that the incentive to reduce costs is reduced and risk is reduced. Please comment.

A. What Ms. Brown fails to take into account is that many of the largest pass-throughs, such as fuel and storm costs, are subject to prudence reviews by the Commission. If costs are found to be excessive or inappropriate, those costs will not be passed through to customers. The threat of a prudence review and potential disallowance, coupled with Surveillance Report monitoring, gives the Commission a great deal of authority to protect customers. It also provides the necessary incentives for PEF to keep costs down. This regulatory approach does not eliminate or reduce risk to the level implied by Ms. Brown. Moreover, this Commission has crafted a regulatory regime in which it focuses much of its attention on base rates. Utilities do not have guaranteed returns. They do not control world energy markets, the financial markets, or mother nature. PEF has real risks *and* a duty to serve. That said, PEF has also been and seeks to remain a superior performer.

Q. At page 4 of his Direct Testimony, Commission Staff witness Mr. Sidney W. Matlock avers that PEF's performance since 2000 or 2001 in the area of

distribution reliability does not warrant adding 50 basis points to its ROE as you have recommended. Please respond to this assertion.

A. First, my recommendation to add 50 basis points to PEF's ROE was not based solely on how PEF had performed with respect to the three measures of distribution reliability (SAIDI, CAIDI, and SAIFI) that Mr. Matlock analyzes in his Direct Testimony. Rather, I based my recommendation on several factors. These include the recent improvements that PEF has made in attaining merger related synergies and implementing cost cutting measures. Included within my analysis were the distribution reliability indices on which Mr. Matlock focused. I also compared PEF's actual cost performance for the three years 2001 to 2003 to the electric industry's performance. I showed that PEF's costs were nearly $400 million per year less than expected based on the industry model.

I also based my conclusion and recommendation on customer satisfaction survey results, improved employee safety, reduced residential base rates, reduced installation costs for new services, an FPSC report that stated that PEF had improved on seven of eight performance metrics, impressive transmission reliability, better than national average fossil steam unit availability, low forced outage rates, high ranking nuclear units, etc. In nearly all these criteria, PEF performs very well, which Mr. Matlock ignores. I realize that Mr. Matlock specializes in distribution reliability, but my recommendation was based on far more than the three distribution related reliability metrics he analyzed.

Q. **Nevertheless, Mr. Matlock does not seem to be overly impressed with PEF's**

improvement in the three areas of distribution reliability that he analyzed. Do you share his assessment of PEF's performance?

A. No, I do not. Mr. Matlock's analysis begins in 1992 and compares the three distribution reliability indices over time. Other than to include one year (1993) that is rather a statistical anomaly, during which PEF had unusually low numbers for the three reliability metrics, I cannot imagine why Mr. Matlock wanted to analyze 11 years of data. Reviewing the period subsequent to 1993 shows a decade of PEF improvement. For example, consider a child that had a great second grade report card. I would certainly be impressed by ten or so years of constant improvement up through high school graduation and I would be less focused on what might or might not have happened in the second grade.

Mr. Matlock states in his Direct Testimony that, with the additional nine years of data, "one may approximate changes in performance since 1992, and see the recent changes in a clearer context." I do not know what he means by this. There is no need to "approximate" changes in performance; the data speaks for itself. As far as seeing recent changes in a clearer context, I do not see how PEF's performance 11 years ago is particularly relevant to analyzing whether PEF has been meeting its recent performance targets, which it has done. I would focus on a decade of improvement, not one distinct year.

Q. **At page 4 of his Direct Testimony, Mr. Matlock lists three "revealing" things about the PEF's 2004 levels of SAIDI, CAIDI, and SAIFI. Please comment on Mr. Matlock's revelations.**

A. Mr. Matlock's first point is that greater improvements were achieved in "earlier periods" than over the years 2001 through 2004. Mr. Matlock does not define with any clarity what this earlier period is. Nevertheless, let's assume that his earlier period begins in the year that the reliability metrics were at their highest (*i.e.,* worst levels). Without question, Mr. Matlock is correct that all three distribution reliability metrics improved more between 1995 (1996 for SAIDI) and 2000 than they did from 2001 to 2004. This is understandable. During the earlier period, PEF was able to make greater improvements picking the low hanging fruit. As SAIDI, CAIDI, and SAIFI scores improved, it became progressively harder and harder to improve. Nevertheless, PEF did continue to improve, as Mr. Matlock admits. For example, consider SAIDI scores. In 1996, PEF's SAIDI score was 130.42. By 2000, it had dropped to 100.60, a drop of almost 30, or a 23% decrease from the 1996 score of 130.42. In 2001, PEF's SAIDI score was 89.70 and by 2004 had dropped to 77.00. This is a decrease of 12.7, representing a 14.1% decrease from the 89.70 posted in 2001. As Mr. McDonald stated in his Direct Testimony, this is a very strong industry performance.

One can always manipulate the numbers by choosing a starting date from which to measure the change. If we were to begin measuring the improvement of SAIDI for the period 1992 (the beginning of Mr. Matlock's data) to 2000, one would see that SAIDI in 2000 (100.60) was virtually identical to the SAIDI in 1992 (103.89). Measured against that earlier time period, PEF's performance in the 2002 through 2004 time period is outstanding.

What is important is that for the most recent, and therefore most relevant period, PEF has performed in an exemplary fashion in reducing its SAIDI, CAIDI, and SAIFI scores. Mr. Matlock does not dispute that PEF's distribution reliability metrics have improved during this period.

This is simply like the student that jumps from a "C" to and "A." After that, moving to an "A+" may be more difficult. When improvement is accomplished, as PEF has done, it should be recognized.

Q. Mr. Matlock's second point is that the "2002 through 2004 improvements were a continuation of improvements that began in 1995 or 1996 following sharp declines in performance after 1993." Please comment.

A. I agree with Mr. Matlock. PEF has sought to continually improve and has succeeded, even as it gets more difficult to make incremental improvements in what is already excellent service quality that is well thought of by its customers and is a strong industry performer. PEF should be rewarded for its efforts to continually improve its distribution service quality and reliability. I cannot imagine why Mr. Matlock is criticizing steady improvement in distribution reliability over an almost ten-year period.

Q. Mr. Matlock's third point is that little overall improvement has taken place over the entire period between 1992 and 2004. Please comment.

A. Again, the numbers contained in Mr. Matlock's Exhibit No. __ (SWM-1) show that this is not true. For example, Exhibit No. __ (SWM-1) shows that SAIDI has dropped to 77.00 from 103.89, almost a 26% decrease from the 103.89. That indicates to me a substantial improvement over the entire period.

Of course, I realize that Mr. Matlock's point is that if we look at the decrease from 1992 to 1993 and compare the 1993 number (78.55) to the 2004 number (77.00), there has not been much of a decrease. This analysis, however, reveals very little useful information. One could just as easily arbitrarily pick the SAIDI from 1996 (130.42) and compare that to the 2004 number (77.00) and tout the incredible job PEF has done in improving distribution reliability. Of course, this would be as meaningless as what Mr. Matlock did. My point is that between 2002 and 2004, the only relevant time period, PEF has undeniably reduced its numbers for SAIDI, CAIDI, and SAIFI.

More important, as I stated above, I did not base my recommendation to add 50 basis points to PEF's ROE solely on its improvement in its distribution reliability. These improvements made up only a part of the reasons behind my recommendation. Nothing in Mr. Matlock's testimony should dissuade the Commission from awarding PEF an additional 50 basis points to its ROE for its outstanding performance.

Q. Have you reviewed the ROE recommendations made by the various Intervenor Witnesses?

A. Yes. Mr. Rothschild is recommending an ROE of 9.1%, Mr. Gorman is recommending an ROE of 9.8%, Dr. Porter states that "an appropriate return on equity for PEF is less than 9 percent", although he does suggest that 10% is an upper bound, and Mr. Stewart adopts Public Counsel's 9.1% recommendation.

Q. How do these ROE recommendations compare to ROEs that have been recently been granted across the country?

A. The ROE recommendations from the Intervenor witnesses are shockingly low. Regulatory Research Associates (RRA) publishes a summary of major rate case decisions. The latest version covers the period January 1990 through December 2004, and reports more than 700 cases where an ROE was authorized. Of these, one base rate proceeding for Jersey Power & Light (Final Order for Docket No. ER02080506, issued May 17, 2004) provided for an ROE of 9.5%. However, if the utility resolved certain reliability issues, its ROE could increase to 9.75%. I found two additional cases out of more than 700 where the authorized ROE was set at 9.75%[6]. Both utilities were located in New Jersey, a state where the electric industry has been restructured, generation divested, and a periodic state level generation auction established. Florida is <u>not</u> like New Jersey. I conclude that Intervenor witnesses' ROE recommendations are far too low based on what virtually every other regulatory decision reported in RRA found to be a just and reasonable ROE. In addition, PEF is significantly growing, adding new generation, and is a strong industry performer. PEF should be authorized an ROE of 12.8%.

[6] PSE&G, Docket No. D-ER-02050303 (July 9, 2003); Rockland Electric, Docket No. D-ER-02100274 (July 16, 2003).

IV. OTHER FLAWED ARGUMENTS MADE BY INTERVENOR WITNESSES

Capital Structure

Q. Beginning at page 9 of his Direct Testimony, Mr. Rothschild argues that PEF's capital structure should be the same as its parent company. Do you agree?

A. No. Mr. Rothschild seemingly ignores one of the important reasons why Progress Energy's (the parent company) capital structure contains almost 58% debt. He should recall that the parent company's capital structure reflects the cost associated with the merger. As I testified in 2002, the merger synergies that provide customers with annual savings that yielded a settlement worth $125 million per year for PEF's customers did not come without a cost. The costs to achieve the merger were borne by the parent company in increased debt. This debt will be repaid to the parent through dividends paid by PEF to Progress Energy.

Mr. Rothschild's approach conveniently looks at only one side of the equation; the merger savings and ignores how these were paid for at the parent company level. The transaction costs necessary to achieve the merger were real. The resulting cost savings were also real. It is not reasonable to use this resulting thick debt percentage and to all too conveniently overlook the fact that PEF's dividends to Progress Energy will repay the costs expended to achieve the synergy benefits. Mr. Rothschild's proposed capital structure coupled with his low ROE recommendation would severely hamper the utility's ability to pay for these merger related costs. This would be unjust and unreasonable because it would falsely support the notion that there are "free lunch" merger benefits that can be had without cost.

Q. At page 22 of his Direct Testimony, Mr. Rothschild disagrees with your statement that as the debt-to-equity ratio increases, the return on debt will begin to increase as bond ratings are lowered, increasing overall rate of return; and that the financial risk of firm is higher as debt-to-equity ratio increases. Please respond to his criticism.

A. Mr. Rothschild admits that my statements may be true for a stand-alone entity. For a wholly-owned subsidiary such as PEF, Mr. Rothschild contends that rating agencies will not consider PEF's equity ratio when setting bond ratings, but will consider only the equity structure of PEF's parent company. This is definitely not true for mortgage-backed debt, which is often used to finance infrastructure. Mr. Rothschild's assertion that rating agencies are unconcerned with the debt-to-equity structure of the regulated utility subsidiary that has pledged to repay debt is unfounded. He offers no support for his bald statement that it is only the parent company's capital structure that matters. Ironically, Mr. Rothschild's (and others') draconian ROE recommendations in this case would make it virtually impossible for PEF to dividend sufficient amounts to the parent company to reduce the debt portion of its capital structure. This would create a Catch-22 where Progress Energy can never improve its bond rating because PEF will be limited in the amount it can dividend up to its parent to reduce the parent's, and in Mr. Rothschild's view PEF's, cost of debt. None of Mr. Rothschild's recommendations would benefit customers in the long-run as the Company's bond rating would decline, its cost of debt would increase, and customers would pay more for energy.

Q. At pages 22-23 of his Direct Testimony, Mr. Rothschild attempts to justify his recommended lower equity percentages in PEF's capital structure by arguing that passing on all storm damage costs to ratepayers reduces risk for shareholders, and lower risk justifies higher debt ratios. Please respond to Mr. Rothschild's contention.

A. First, I must take exception to Mr. Rothschild's characterization that PEF recovered all its storm damage cost. What PEF will recover over two years is the storm damage cost recovery approved by the Commission. In the recent storm damage docket, PEF's actual recovery was not 100%, but closer to 90%, and there have been deferrals of recovery. While a substantial percentage has been approved, it is <u>not</u> the 100% claimed by Mr. Rothschild.

In fact, the Commission pushed about $54.9 million into a capital account potentially to be recovered in this rate case. In addition, the Commission disallowed about $26.3 million in O&M expense recovery. Further, the Commission recognized these deferrals and disallowances combine to reduce PEF's 2004 ROE from 13.48% to 12.66%, or a loss of 82 basis points in shareholder value. Without reopening the storm recovery case, this is not a 100% recovery of storm costs.

Forcing shareholders to pay for and to defer collections with or without a return on the prudently incurred costs related to the four hurricanes that devastated PEF's service territory in 2004 does not reduce risk to shareholders to the extent implied by Mr. Rothschild. On-going prudence reviews also increase uncertainty and add to shareholder risk.

PEF did not receive an automatic pass through of these storm related costs. Rather, it underwent a time-consuming and contentious hearing on whether its expenditures were prudent and incremental. PEF was, consequently, at risk if the Commission had decided that certain of the costs were not prudent. Lost in the shuffle were the more than $11 million in sales PEF lost as a result of these storms. Shareholders have eaten storm costs for a variety of reasons. Thus, I disagree with Mr. Rothschild that storm damage risk was eliminated for the past storm.

Q. But did not the Commission itself state that shareholder risk was reduced because of the storm damage recovery clause?

A. The Commission did state in its order that it would be cognizant of the fact the ratepayers bear the risk of storm damage recovery when it determined the Company's ROE in this proceeding. However, the Commission also recognized that it retained its authority to review the prudence and reasonableness of the charges incurred, including whether specific charges were properly allocated to the storm damage reserve. This also adds an element of uncertainty to the storm cost recovery. Importantly, the Commission also observed that it continues "to be supportive of the financial integrity of PEF and, by extension, the long-run interests of its ratepayers."[7] My point is that if the Commission follows Mr. Rothschild's recommendations with respect to PEF's capital structure and ROE, PEF would be severely harmed, and by extension, the long-run interests of its ratepayers would suffer.

Further, the Commission is actually addressing ratepayer risk, more than shareholder risk, when it increases the storm reserve. This is because storms are uncertain and potentially costly. The Commission, in effect, has recognized the 2004 storms as a potentially new source of future ratepayer uncertainty. Spreading legitimate ratepayer costs over many years, such as building up reserves in years with less storm damage than the amounts collected for storm reserves, seems like a better regulatory approach to insure customer pricing stability and a greater degree of ratepayer certainty than waiting to recover all future "big storm" costs in the two years or so subsequent to when the storms occur. At the very least, smaller volume customers would seem to prefer this Commission-approved insurance approach rather than to be forced to pay temporarily higher rates when the next severe storms hits and PEF's customers have their own storm costs as well.

CWIP.

Q. At page 25 of his Direct Testimony, Mr. Larkin states that Construction Work in Progress (CWIP) should not be included in rate base. Do you

[7] In re Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Docket No. 041272-EI, Order No PSC-05-0748-FOF-EI (July 14, 2005).

concur?

A. No. Mr. Larkin's point of view is short-sighted and will, in the long-run cost consumers more in terms of higher consumers' revenue requirements. Historically, there was a long debate about whether CWIP should be included in rate base. That debate, I had thought, was previously settled and CWIP had been found to be better for consumers than AFUDC.

Mr. Larkin in this proceeding is clearly anti-CWIP. He is, however, ambiguous when it comes to the alternative (AFUDC), which is most often used when construction schedules, as they are here, are mostly longer than one year. PEF's CWIP balance has about $145.8 million in generation related dollars alone according to PEF's MFRs (Schedule B-13).

After dismissing CWIP, Mr. Larkin proceeds to discuss AFUDC as an alternative. On page 30, lines 6-7, he states that the Commission "may require the accrual of AFUDC." Here, Mr. Larkin appears to remove CWIP, but remains silent on future AFUDC recovery. I will discuss why CWIP is more preferable for consumers than AFUDC. I also think that this Commission, despite Mr. Larkin's ambiguity, should continue to recognize that carrying costs during construction are real and part of the just and reasonable cost recovery of prudent investment costs.

In essence, when a utility is building a generating plant or transmission line, the cost of the asset will be placed into rate base when the plant is placed in service, or is considered "used and useful." While the asset is being constructed, the utility will incur financing charges on the money it borrows to construct the asset. If CWIP, or the carrying cost during construction that may spread over several years, is not permitted to be recovered, the constructions costs, along with these carrying costs incurred during construction, are added to rate base in the form of AFUDC when the project is placed into service. This increases the amount on which the utility may earn a return and recover depreciation over the life of the facility. If CWIP is permitted in rate base, the utility will earn a current return in rates on the funds used in construction. The effect is beneficial to both the utility and its ratepayers because, as a rule of thumb, each one dollar deferred and added to rate base, costs customers about three dollars in higher future revenue requirements.

Q. How is it beneficial?

A. CWIP is beneficial to the utility in that it helps the utility to maintain its financial integrity. PEF is facing strong customer growth and must undertake substantial construction projects to meet this growth and new environmental requirements. In determining whether to include CWIP in rates, the Commission should consider things like slippage in coverage, the need for outside financing, and the quality of earnings. These things all tip the scales in favor of allowing CWIP in rate base. It is simply less costly to pay now when it can be affordable to do so than paying much more later. The utility benefits because allowing CWIP increases the certainty of recovery, provides cash flow to support the construction, and reduces the need to borrow more debt and/or raise more equity.

Q. How do ratepayers benefit?

A. Ratepayers benefit because, even though they pay somewhat increased rates in the early years of the project, costs are significantly reduced in later years. If, as Mr. Larkin recommends, the finance charges are added to the cost of the asset, when the asset is eventually placed into rate base, it will be more expensive for the ratepayer than if it were gradually placed into rate base under CWIP. By spreading the costs over the construction period and the life of the facility, the effect on rates is minimized and, as I explained, the rule of thumb is about three dollars in the out years less than when CWIP is collected in the current year.

Q. Please explain why CWIP is less expensive for ratepayers.

A. By delaying the collection of interest expense to some future date under AFUDC accounting, customers will likely pay for both a return of and on the AFUDC at future rates of return. There is little doubt that the future revenue requirements will increase as both the rate base and quite likely the underlying authorized rate of return on rate base are increased with higher future finance costs than today's low interest charges by delaying and capitalizing the collection of interest during the construction period.

In the long-run, Mr. Larkin's argument to prohibit CWIP would increase ratepayer costs. Additionally, CWIP allows the cost of the project to be absorbed through a series of small rate increases. AFUDC results in an increased project cost and a large rate increase when the project is placed in rate base. Disallowing cost recovery of real carrying costs would be the worst outcome because it would undermine a utility's financial integrity and strength, forcing consumers to pay dearly. The choice is between "pay now" or "pay more later." I think that the pay more later approach advocated by Mr. Larkin harms both the utility and the ratepayer and should be rejected.

Q. Does this come down to a question of customers' discount rates and intergenerational equity?

A. Yes. These are both important, but mostly separate matters. Construction often takes time and any deferral of finance costs is a real cost. The fact is that it is simply cheaper to pay sooner than to finance the deferral of prudent cost, or worse simply wishing them away.

This raises the intergenerational issue and the related "used and useful" standard. Consumers today are often people building homes, adding to them, adding to their families, and working, building, and expanding their businesses. All of these current activities require electricity now and in the future. Few consumers would accept a deal where power was here now, but it may not be available in the future without some form of rationing.

Of course, PEF plans and builds ahead so that there will not be any future rationing. This means that customers today benefit from prudent investments under construction. Customers today, in effect, benefit because PEF plans and builds for future needs. There is no free lunch here. Current customers benefit, "use", and find "useful" PEF's plants, transmission, and distribution when these assets are under construction.

Once this is recognized, we can and should embrace the mantra that it is cheaper to pay now, rather than later.

Q. Please explain the logic you use to conclude that an asset can be used and useful before it is placed in rate base?

A. In a very real and important sense, current construction being undertaken by PEF represents a used and useful investment for today's customers, who either care about tomorrow for themselves, the value of their current estates and property, or for their children and heirs. It is today's level and pattern of use that causes a utility to need to add capacity. Current customers are responsible for this growth just as surely as the "newcomers." This is a fundamental economic principle. To allocate otherwise is to practice a vintaging form of price discrimination.

It is also the case that "not building" today would cause problems for present and future customers who would both expect reliable and relatively affordable service tomorrow, and the next day, etc. Postponing the news that today's use is causing tomorrow's plants to be built today encourages greater use today, more construction, and higher prices tomorrow. The latter is directly related to AFUDC accounting, increased financial risks, reduced cash flow/quality of earnings, and increased growth in sales.

Q. Why is this important for PEF?

A. PEF is a utility faced with a rapidly expanding customer base that will require substantial new investments in the near future in generating plants, transmission, and distribution. Additionally, environmental upgrades are required under federal law. If CWIP is not permitted, PEF will be responsible for the carrying charges on these investments until the projects are placed in rate base. This will put financial pressure on PEF, and ultimately will cause customers to pay more for the plants than they would have if the carrying charges had been phased into rate base during construction through CWIP.

Q. At pages 50-51 of her Direct Testimony, Ms. Brown recommends removing $82.1 million in CWIP from rate base. Please respond to her recommendation.

A. Ms. Brown bases her recommendation solely on the fact that PEF can maintain the EBIT times interest coverage necessary for an A rating even when CWIP is removed from rate base. Thus, reasoning that CWIP is to be included in rate base solely to maintain the utility's financial integrity, Ms. Brown concludes that it is not necessary to include the $82.1 million in CWIP. As I discussed above in response to Mr. Larkin, this is a short-sighted approach. There are more factors than financial integrity in play with CWIP. Most important is how customers will be required to pay for the "real" construction period finance costs. Removing the $82.1 million in CWIP will, as Ms. Brown correctly notes, have the short term effect of reducing PEF's revenue requirement. However, in the long-run, ratepayers will pay more for the assets that are eventually placed into rate base, as well as more for PEF's financial costs. In fact, the rule of thumb for IOUs is about $3 more for each $1 deferred for a 30-year cost recovery. More would be added here if PEF's debt is also downgraded. These are bad things for customers. Consequently, Ms. Brown's recommended adjustment to CWIP should be rejected.

V. CONCLUSION

Q. Please state your conclusions.

A. My conclusion and opinions remain the same as stated in my Direct Testimony. I restate them here. First, it is crucial that PEF's outstanding job since the merger in achieving merger related savings and other cost cutting efforts that make PEF a superior performer be recognized. The effects of these efforts are demonstrated by both the internal and external statistical benchmarking analyses. PEF has improved when measured against its pre-merger performance or against its peer companies across the nation. This effort continues and PEF should receive both recognition and incentives to finish the tasks ahead.

Customers have already reaped the benefits of the merger through a settlement in 2002 that yielded a $125 million annual base rate reduction. Customers also received $45.9 million in revenue sharing benefits. PEF needs rate relief now primarily to account for new customer requirements, including generation being placed in rate base and to restore and expand the storm reserve fund. Both will yield consumer benefits. I find the Intervenor witnesses improperly try to ignore the savings already provided to ratepayers. Worse, their collective testimonies would, in effect, penalize PEF for building new generation, improving reliability, and adding customers. More importantly, Intervenor witnesses seem to "forget" about the costs that were incurred by Progress Energy that enabled PEF to achieve these merger related savings for its customers. These transaction costs need to be repaid. This would enable the parent company to reduce its debt and improve its debt equity structure, improving its ability to improve its bond rating, which Intervenor witnesses think would improve PEF's ability to improve its bond rating. I remain firmly convinced that this Commission should continue to provide appropriate incentives that encourage PEF to continue its exemplary cost cutting such as establishing PEF's ROE at 12.8%. Similarly, the Commission should be applauded for its recognition that a financially strong PEF will, by extension, inure to the long-term benefits of ratepayers. In addition, there should be explicit recognition that building more generation, improving infrastructure, and reducing future price volatility risk by expanding the storm reserve fund all benefit consumers. These benefits exceed the costs. However, these are real costs and PEF needs rate relief to achieve these and other benefits.

With that overarching policy matter firmly in mind, I conclude that the 12.3% ROE recommended by Dr. Vander Weide is a reasonable floor, to which the Commission should add 50 basis points to reward PEF for its superior performance and encourage PEF to continue its efforts. Thus, I conclude that an ROE of 12.8% is appropriate.

Further, in keeping with the general regulatory flavor of providing an incentive for the Company to continue along its current path, I support Dr. Vander Weide's recommended 45/55 debt to equity ratio. Further, I conclude that PEF's approach to include purchase power costs as part of the debt component should be implemented here because these costs are analogous to debt that would be incurred if PEF financed and built power plants to provide the power received under these purchase power contracts.

It is important to keep in mind the fact that PEF is located in a traditional state that has eschewed deregulation. As my statistical analysis demonstrates, PEF is a superior performer with respect to cost levels and also needs to invest in infrastructure to serve its expanding, primarily residential, customer base. PEF, as others have shown, has also improved the quality of its service and its reliability performance. PEF should be rewarded with an authorized ROE at the higher end of the range of reasonable ROEs. Further, PEF's superior performance should be recognized by adding 50 basis points to the ROE authorized by the Commission. This should be coupled with a 45% debt, 55% equity capital structure.

By doing these forward looking things, the Commission can help ensure that PEF is able to attract capital at reasonable prices to finance its infrastructure improvements. By so doing, the Commission will be providing long-term customer benefits that will last 30 years or longer. Such regulatory treatment will also ensure that savings associated with the merger, other cost cutting benefits, and safety and reliability improvements will continue to be made. In adopting such a reasonable regulatory treatment, the Commission will provide benefits to both customers and shareholders, a symmetry that is required for the continued success of the Company and the welfare of its customers.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

REBUTTAL TESTIMONY OF
WILLIAM C. SLUSSER, JR.

Q. Please state your name.

A. My name is William C. Slusser, Jr.

Q. Did you submit direct testimony in this case on April 29, 2005?

A. Yes, I submitted direct testimony that addressed the general area of cost of service and rate design.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony primarily focuses on rebutting assertions and positions contained in the testimony of White Springs witness Maurice Brubaker regarding a refinement recommended in my testimony to the traditional cost allocation methodology used by the Commission for allocating fixed production costs to customer classes, and the proposal presented in my testimony to complete the closure of PEF's non-cost-effective Interruptible and Curtailable Rate Schedules IS-1, IST-1, CS-1 and CST-1. I also address the testimony of the Commercial Group witnesses Michael T. O'Sheasy, Mike Culver and Charlie Martin regarding real-time pricing. Finally, I present a revised jurisdictional separation study based on the updated sales forecast presented in the rebuttal testimony of Company witness John B. Crisp.

Q. Have you prepared any exhibits for use in conjunction with your rebuttal testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits:

- Exhibit No. ___ (WCS-7), Development of Fuel Savings Resulting from Existing Generation Fleet as Compared to Peaking Only Resources.
- Exhibit No. ___ (WCS-8), Cost of Production Plant When Allocated Using 12 CP and 25% Energy.
- Exhibit No. ___ (WCS-9), 1983-84 Load Factor/Coincidence Factor Curve.
- Exhibit No. ____ (WCS-10), Revised Jurisdictional Separation Study.

These exhibits are true and accurate.

<u>Allocation Of Production Capacity Costs</u>

Q. What is Mr. Brubaker's position regarding your recommended cost of service study that allocates 75 percent of fixed production costs based on the customer classes' 12 monthly coincident peak demands and 25 percent of these costs based on the classes' average hourly demand, *i.e.*, annual energy usage?

A. In his testimony, Mr. Brubaker takes the position that the capital costs of production facilities are fixed costs which are traditionally treated as demand-related and should be allocated to customer classes on some form of demand or coincident demand basis, rather than on an energy basis which is traditionally used to allocate cost that vary with production output, such as fuel costs. He contends that the allocation methodology recommended in my testimony addresses only the capital side of the trade-off between capital and fuel in the selection of generation type and ignores the fuel side. This is because he contends a study of the type of generation that would be built to serve each customer class individually, which neither he or I have ever conducted, would show that more base load generation would be installed to serve high load factor classes. He says that this would result in these classes having more fixed costs relative to low load factor classes, but that they would also have lower fuel costs. Mr. Brubaker concludes that the methodology recommended in my testimony lacks the proper symmetry because although it allocates higher fixed costs to high load factor classes consistent with his single-class generating system, my methodology fails to address the allocation of lower fuel costs that he believes these classes should receive in return for their higher fixed costs.

Q. How do you respond to Mr. Brubaker's criticisms of your allocation methodology?

A. His criticisms would be valid if the current allocation of fixed production costs (often called production capacity costs) and fuel costs between the high load factor and low load factor customer classes was relatively balanced and even-handed. As Mr. Brubaker correctly recognizes, the methodology I recommend does, in fact, result in the allocation of more overall costs to high load factor classes and less costs to low load factor classes compared to the status quo. However, the current situation is far from balanced with respect to the equitable allocation of production costs between these two groups of customer classes.

Even with the moderate cost shift to the high load factor classes under the allocation methodology I recommend, those classes will still not bear their full cost responsibility for PEF's most efficient, and most capital intensive generating facilities, and they will continue to enjoy a greater than average share of the fuel cost savings produced by these generating facilities by virtue of their high energy usage. In this regard, there is a certain irony in Mr. Brubaker's criticism that my methodology ignores the fuel side of capital/fuel trade-off, since the most compelling reason for proposing this methodology is the failure of the current allocation methodology to require adequate cost responsibility on the high load factor classes for the substantial fuel savings they receive.

Q. Aside from his criticism of the methodology proposed by PEF for allocating production capacity costs, Mr. Brubaker claims that the application of this methodology would result in over-charging the high load factor customer classes. Do you agree?

A. No, I do not. Mr. Brubaker's argument is simply another way of expressing his initial argument that if high load factor customer classes have to pay for a greater share of capital intensive generation, then they should receive the benefit of the lower fuel costs associated with this generation. This argument has already been adequately refuted and stating it differently does not make it more meritorious. In any event, no matter how Mr. Brubaker may phrase or rephrase his position, it will not change the fact that the high load factor customer classes will not be over-charged by the application of the Company's production capacity cost allocation methodology. I say this for a number of reasons.

First, the high load factor classes are being under-charged by the current method of allocating capacity costs. As I explained earlier, these classes receive a much greater share of the fuel savings produced by high cost generation than the share of the generation costs that have been allocated to them. The high load factor classes may not receive treatment quite as favorably under the proposed allocation methodology as they currently enjoy, but they certainly will not be over-charged.

Second, even though the high load factor classes have benefited greatly by receiving the system average cost of fuel, Mr. Brubaker complains that these classes should receive the fuel costs of more efficient, capital intensive units. For all intents and purposes, they do. The only generation type with a sufficiently high fuel cost to significantly increase the system average cost of fuel is the Company's peaking units. However, this potential has little chance of being realized because peaking generation provides only 2.6% of the Company's system energy requirements, as can be seen on Mr. Brubaker's Exhibit No. ___ (MEB-6). This small contribution of peaking generation increases the average fuel costs of PEF's other generating units by only about 5%, from $31.38 per megawatt-hour (MWH) to $33.03 per MWH. Furthermore, even during the few hundred hours a year that peaking generation operates, the most it can contribute to the Company's total generation is 27%. During these hours, when all customer classes are likely to be contributing to the peak demand and sharing in the higher cost of fuel, the high load factor classes bear only a portion of this cost responsibility. During the remaining 8,000 or more hours of the year, only non-peaking generation is in operation. This means that the high load factor classes are, in fact, receiving the lower fuel costs from PEF's more efficient, capital intensive generating units over 95% of the year.

Third, most large high load factor customers, including the customer Mr. Brubaker represents, receive interruptible service under PEF's optional Time-Of-Use (TOU) rate. Customers under this rate receive a discount on their fuel charges that averages about $1.00 per MWH below the system average fuel cost charged to all other customers. And, of course, the more consumption these TOU customers shift to off-peak periods, the more savings the discount produces for them. This is another reason why most high load factor customers will continue to fare well under rates set using the Company's proposed cost allocation methodology.

Lastly, the methodology proposed by the Company in this case allocates only 25% of its production capacity costs on an energy basis. However, PEF's actual production investment is about 50% greater than it would be if capacity had been built only to meet peak load. This means that an allocation of 50% of PEF's total production investment on an energy basis would be justified. Thus, if anything, the proposed 25% energy allocation methodology is under-assessing the high load factor classes their full cost responsibility for the fuel savings they receive from this additional investment.

Q. **Have you prepared an exhibit that demonstrates the benefits being derived by each rate class as a result of PEF constructing more capital intensive units to achieve fuel savings?**

A. Yes. I have prepared Exhibit No. ___ (WCS-7) that shows an energy allocation, by customer class, of all additional production capacity costs incurred to achieve greater fuel savings, *i.e.*, 50% of total production capacity costs. These energy allocated capacity costs are compared to the fuel savings produced by this additional production capacity, which represent the difference between the fuel costs associated with the Company's existing generating fleet and the fuel costs associated with a generating fleet designed to serve peak demand only. Not only does this exhibit demonstrate the huge benefit derived by PEF for making investments in more capital intensive facilities, it also demonstrates the equity of allocating a portion of the capital cost premium paid for these facilities on an energy basis.

Q. **Mr. Brubaker also claims that the Company's cost allocation methodology is wrong because it allocates the additional capital costs of capacity installed for fuel savings to all energy usage, rather than energy usage up to an economic**

"break-even point" between the operation of a peaking unit and the unit installed for fuel savings. Do you agree?

A. I disagree with Mr. Brubaker's conclusion that the Company's cost allocation methodology is wrong. However, I have no difficulty agreeing that the methodology, while based on the outcome of the generating unit selection process, does not utilize the analytical details of the process itself.

To explain what I mean by this, let me begin by saying I agree that from a system planning standpoint, the selection of a high capital cost/low fuel costs generating unit (a base or intermediate-load unit) instead of a low capital cost/high fuel cost unit (a peaking unit) is justified by the base-intermediate unit's hours of operation up to the economic break-even point between the two types of units. One of the reasons PEF's methodology does not employ the specifics of this analytical process is that it represents a marginal cost perspective, *i.e.*, the notion that marginal cost of usage greater than the break-even point requires no additional investment. The problem with this perspective is that, for the most part, utility ratemaking practiced by this Commission is based on average costing principles in order to avoid the inequities and practical difficulties that can result from the use of marginal costing when setting rates.

The kind of equitable and practical difficulties a marginal pricing principle can produce in the ratemaking process is illustrated by Mr. Brubaker's "break-even point" criticism. He uses this form of marginal cost analysis to support his contention that the Company's methodology allocates too much production capacity cost to high load factor customers on the basis of energy. In actuality, however, the opposite is true. As I have explained, the methodology proposed by PEF allocates 25% of its production costs on an energy basis. Yet, the Company's actual production investment made to reduce the cost of energy, *i.e.*, fuel, would justify allocating 50% of its total production investment on an energy basis. Moreover, allocating even this higher level of production costs based on energy usage would still not be excessive, since it would amount to only a fraction of the fuel cost savings achieved by the additional investment, as can be seen in my Exhibit No. __ (WCS-7).

Another reason that the break-even analysis is not used in the Company's methodology is that, while the analysis may be well suited to the initial selection of a generating unit in the planning stage, it does not reflect the unit's actual costs and benefits after it has been placed in service. In actuality, the fuel cost savings produced by a kWh generated after the marginal cost break even point is just as real and valuable as the fuel savings from kWh generated before the break even point is reached. A cost allocation methodology that recognizes the latter but ignores the former is not a proper methodology. I believe that from an equitable and a practical point of view, all customers that benefit from a unit's economic selection decision should also share in the cost to achieve the benefits.

PEF has opted for a moderate, middle ground approach in the allocation of production capacity costs and therefore has not attempted to fully implement the capital substitution concept. Instead, the Company has proposed a cost allocation method that gives a greater recognition to the important role capital substitution plays in the selection of the Company's production capacity. This is intended to result in a better and more equitable allocation of the significant costs that flow from this selection process, while retaining the structure of the current allocation methodology that has been employed by the Commission for many years.

Q. In his Exhibit No. ___ (MEB-5), Mr. Brubaker attempts to show that using PEF's methodology for allocating production plant investment will result in

an above average cost per kW of demand for the high load factor rate classes? Would you comment on this exhibit?

A. It appears to me that the calculations shown in Mr. Brubaker's exhibit are more for effect than for any insight into the significance of the Company's methodology. To illustrate how variations in presentation can change the appearance of cost allocation results, my Exhibit No. __ (WCS-8) shows a calculation similar to Mr. Brubaker's using the same allocations of production capacity costs to the customer classes, but with the results expressed on an energy basis in terms of cost per MWh. The first six numbered lines of the exhibit contain the same information that Mr. Brubaker presents in his Exhibit No. ___ (MEB-5). The information on lines 7, 8, and 9 shows that the Company's allocation method results in a favorable, below average production capacity cost per MWh for the high load factor rate classes.

Coincident Peaks To Use In Cost Allocation

Q. Mr. Brubaker recommends that class coincident peak demand for either the winter peak or the average of the summer and winter peaks be used in lieu of the average of the twelve monthly peaks to establish cost responsibility for production capacity costs. Do you consider this method to be appropriate for PEF?

A. No. First, Mr. Brubaker attempts to show in his Exhibit No. ___ (MEB-7) and (MEB-8) that PEF experiences a strong winter peak. However, he fails to consider supply-side conditions, which would have shown that the Company's greater winter peak load is totally mitigated by additional resources for the winter period from (a) higher generator capability ratings, (b) ownership of a shared peaking resource, and (c) greater load management capability.

As for his portrayal of lower peak loads during non-winter or non-summer shoulder months, he fails to consider the corresponding reduction in available generation resources because of planned maintenance outages for the Company's larger units. The fact that available generation tends to track seasonal fluctuations in load provides strong support for the recognition of peak demand in all months. For this reason, PEF considers contributions to the average of the 12 monthly peaks to be an appropriate basis for the demand component in the allocation of production capacity costs.

Interruptible Credits

Q. Mr. Brubaker suggests that an interruptible credit be established based on the revenue requirement associated with a combustion turbine? What is your response to this suggestion?

A. To begin with, I believe Mr. Brubaker has made his suggestion in the wrong forum. PEF's interruptible and curtailable service are Demand-Side Management (DSM) programs. As such, these programs are subject to Commission review and approval every five years in the Conservation Goals proceeding and annually in the Energy Conservation Cost Recovery (ECCR) docket.

As it relates to Mr. Brubaker's suggestion, the cost of PEF's payments for interruptible billing credits are approved by the Commission in the ECCR docket in accordance with cost-effectiveness criteria based on a comparison with the Company's avoided unit or units. It is my understanding that any proposed change to an approved DSM program requires Commission approval in order for the program's cost to be eligible for recovery through a utility's ECCR clause. For this reason, I believe the proper forum for a change in PEF's interruptible billing credit, particularly a major change of the kind proposed by Mr. Brubaker, is the

Commission's ECCR proceeding. In fact, the Commission's action to close the Company's IS-1 and IST-1 rate schedules to new customers was taken in the ECCR proceeding and was based on a finding that the interruptible billing credits in those rate schedules were no longer cost-effective. These are the same interruptible rate schedules that PEF has asked the Commission to close permanently.

In the event the Commission considers Mr. Brubaker's proposal to be within the scope of this proceeding, I will briefly address the merits of his proposed method for establishing the interruptible billing credit. In my opinion, the credit for this DSM program should be established using the same cost-effectiveness criteria and analysis as used for all other DSM programs. From my review of the DSM calculations last used to support the interruptible credit, I have concluded that Mr. Brubaker's suggested method would not be cost-effective. However, a thorough evaluation has not been performed by anyone to my knowledge, and any decision on the merits would therefore be premature at this point.

<u>**Method of Applying the Interruptible Credit**</u>

Q. Mr. Brubaker claims the Company's method of applying the interruptible credit in its IS-2 and IST-2 rate schedules using a load factor adjustment understates the value of interruptible power and further adds to the increases he claims interruptible customers would experience. Do you agree?

A. No, I do not. Under either rate design, the same total amount of credits is distributed to customers in the rate class. The Company simply believes that the load factor adjusted credits included in the IS-2 and IST-2 rate schedules are more equitable to the customers within the rate class than the unadjusted credits included in the IS-1 and IST-1 rate schedules.

Furthermore, I am not sure that Mr. Brubaker fully understands the Company's rate design when he states in his testimony that a customer with a 75% billing load factor would experience a reduction of 25% in the level of the credit. This is an incorrect statement, since the customer with a 75% load factor in his example will actually receive a greater credit under the Company's rate design employed under IS-2 and IST-2 than under a rate design where the credit is based on a customer's maximum demand, such as in the Company's older IS-1 and IST-1 rate schedules. I will walk through the calculations for the rate design of these two credits in an attempt to demonstrate this point.

Under the Company's rate design, the rate credit for 1 kW coincident with the system peak is $3.08. A customer with a 75% billing load factor would receive a credit for each kW of billing demand equal to 75% of the $3.08, or $2.31.

Under a rate design in which the credit is applied to the customer's billing demand without any adjustment and is designed to provide the class the same total revenue credits as in the Company's rate design described above, the rate credit for 1 kW on a billing demand basis must be equal to $1.85 per kw of billing demand. In rate design work, this is derived by multiplying the value on a coincident demand basis by the ratio of the class's coincident demand to its billing demand. (For the IS class, the ratio of the class's coincident demand to its billing demand is approximately 0.6.) Thus, under this rate design, the customer would receive $1.85 in credit, less than the amount in the Company's rate design.

Q. Why do you believe the credit rate design employed in the IS-2 and IST-2 rate schedules is more equitable to the customers within the interruptible rate class than the method of applying a credit to the customer's billing demand without any adjustment?

A. I have prepared my Exhibit No. ____(WCS-9) in order to demonstrate this point graphically. I prepared the exhibit by plotting current information on a graph I recently located from a Commission workshop presentation in 1985 on general service rate design.

The graph shows the typical relationship between a general service customer's monthly demand at the time of system peak and the customer's monthly load factor. This relationship is often referred to as the "Bary" curve – named after Constantine W. Bary, a noted rate engineer, who first established the relationship in the 1930's. The "Bary" curve indicates a curvilinear increase in coincidence factor as monthly load factor increases. PEF performed considerable load research on its general service customers in the mid 1980's and confirmed this relationship. The graph applies the interruptible credit amount of $3.08 per coincident kW to the "Bary" curve data points to derive the appropriate credit due a customer as a function of load factor. The graph then plots the two rate designs over the appropriate "Bary" curve credit relationship. It is obvious that the rate design which provides a credit in proportion to load factor is a superior rate design to the one that provides the same credit to all load factor customers. This rate design provides a more equitable distribution of credits over the load factor range of customers in the class.

DEVELOPMENT OF INTERRUPTIBLE CREDITS FOR STANDBY RATES

Q. Mr. Brubaker claims the Company's calculation of the credit for interruptible standby rate service is wrong. Do you agree?

A. No. I find that the rate credit is a straight forward calculation and is the product of: (a) 10%, which is the expected amount of standby load imposed by a customer having an assumed 10% unavailability of his generation and (b) $3.08 per kw, the value assigned for interruptible load on a monthly CP basis. As I explained in my direct testimony, the standby rate credit in the present SS-2 rate schedule was established to relate to the interruptible credit value being afforded the IS-1 and IST-1 rate schedules. This value was $6.42 per coincident kW, which when multiplied by 10% results in the credit shown in the present SS-2 tariff. With the proposed complete closure of the IS-1 and IST-1 rate schedules, the standby rate credit in the proposed SS-2 rate schedule has been established to be consistent with the interruptible credit value in the IS-2 and IST-2 rate schedules. This value is $3.08 per coincident kW, which when multiplied by 10%, results in the credit shown for the proposed SS-2 tariff.

Some of the confusion with Mr. Brubaker's analysis may be related to the type of kW that the credit applies. Note that above, I cited the derivation of the present SS-2 tariff as being based on the value of $6.42 per coincident peak kW, whereas, the credit provided in the IS-1 and IST-1 rates is $3.70 per billing kW. The $3.70 figure was derived by multiplying the $6.42 by the ratio of the class's coincident kW to its billing kW. For the proposed IS-2, and IST-2 tariffs, the value of an interruptible kW that is completely coincident with the system peak is $3.08. This value is then adjusted for the customer's coincident demand, an estimate of which is determined by the product of billing demand and load factor. This last step is the load factor adjustment and is used to convert billing demand to coincident demand.

<u>**REAL TIME PRICING (RTP) RATES**</u>

Q. The Commercial Group's joint witnesses, Mike Culver and Charlie Martin, are asking PEF to consider witness Mike O'Sheasy's RTP rate design for application to commercial customers like J.C. Penny and Lowe's for whom

they are respectively employed? What is PEF's response to the application of this rate design?

A. PEF has been aware of RTP pricing, and in fact, previously developed a rate offering of a form of RTP pricing for application to large general service firm customers. After two years, during which not a single customer had chosen to take service under this offering, the rate was withdrawn for lack of customer interest. Admittedly, Mr. O'Sheasy's rate design is a different form of RTP pricing than previously offered by the Company, but like the Company's previous design, it requires the customer to have the flexibility and capability of altering its load on an hourly basis to be of any value.

The joint witnesses have indicated that their respective companies have made substantial in-house energy management efforts and have built energy efficiencies into their facilities. PEF's general service demand time of use rate offering does provide an incentive for these type of companies to engage in energy management and conservation efforts. These efforts generally result in reduced or fixed shifting of loads, and the ability to further change load on an hour-to-hour basis under RTP pricing incentives is questionable.

Nevertheless, the Company remains open to discuss and work with its customers and their rate consultants such as Mr. O'Sheasy on RTP pricing or any other innovative rate design where it can be demonstrated that there are cost savings with which to justify such an offering.

<u>**EEI Typical Bill Cost Comparisons**</u>

Q. In the joint Direct Testimony of Mike Culver and Charlie Martin, the witnesses express a belief that something was wrong with the Company's cost of service analysis for commercial users, since they found that PEF's

commercial rates were comparable to its residential rates, yet PEF's commercial classes are substantially below parity with respect to the classes' rate of return. Do you share their concern?

A. Yes, when I read their testimony and reviewed their exhibit, I also found it surprising that PEF's commercial rates were shown to be only comparable and not lower than its residential rates in the witnesses' Exhibit No. ____(CM-1), which is based on data from the Edison Electric Institute's "Typical Bills and Average Rates Report", Summer 2004 and Winter 2005. Upon investigation, I found that PEF had reported erroneous data to EEI regarding the Company's Winter 2005 commercial rates, and as I initially expected, the corrected commercial rates are about 2.0 cents per kwh less than the rate for residential service. The erroneous data also appears in Mr. Brubaker's Exhibit No. ___ (MEB-3), pages 3, 4, and 5, which places PEF's rate level ranking higher (worse) than it should be.

<u>Revised Jurisdictional Separation Study</u>

Q. What is the purpose of the revised Jurisdictional Separation Study that you have included with your testimony as Exhibit No. ___ (WCS-10)?

A. I have prepared the revised Jurisdictional Separation Study to recognize two significant factors which were not reflected in the Company's original filing in this proceeding, but which are now the subject of rebuttal testimony by other Company witnesses.

The first factor concerns the change to the Company's system and customer base associated with the sale of its electric distribution system in the City of Winter Park, which was raised principally in the testimony of Office of Public Counsel witness Donna DeRonne, as well as other intervenor witnesses. The witnesses have raised several issues regarding the sale and the related loss of PEF's retail service territory and customers within the City.

The revised separation study reflects Winter Park's 12 coincident peak monthly load of 85,917 MW and its annual system energy requirements of 505,901 MWH as wholesale service under a full requirements service contract entered into between PEF and the City. The study also reflects the changes in distribution and customer-related costs described in the rebuttal testimony of Company witness Javier Portuondo.

The second factor reflected in the revised separation study relates to the Company's updated sales forecast described in the rebuttal testimony of Company witness John B. Crisp. The revised separation study includes changes in jurisdictional loads, billing determinants, and resultant sales revenues produced by the updated sales forecast.

Q. Have you prepared a revised Allocated Class Cost of Service and Rate of Return Study to reflect the revised jurisdictional cost of service which you are now submitting?

A. No, I have not. In my opinion, it would be more appropriate to prepare a study after the Commission's final decision on overall cost of service and class allocation methodologies. The Company would then endeavor to produce a study as rapidly as practicable for the Commission's use in determining final class revenues and rate design.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

REBUTTAL TESTIMONY OF STEVEN P. HARRIS

ON BEHALF OF PROGRESS ENERGY FLORIDA, INC.

I. Introduction.

Q. Please state your name and business address.

A. My name is Steven P. Harris. My business address is ABSG Consulting, Inc. ("ABS Consulting"), 1111 Broadway Street, Oakland, California 94607.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to portions of the testimony submitted on behalf of Office of the Public Counsel by Helmuth W. Schultz, III; The Florida Retail Federation by Sheree L. Brown; and AARP by Stephen A. Stewart, addressing the estimated annual storm loss on Progress Energy Florida's ("PEF") system and those witnesses' respective calculations of a proposed annual Storm Damage Accrual amount.

Q. Are you sponsoring any exhibits to your rebuttal testimony?

A. Yes. I am sponsoring the exhibits that follow:

- Exhibit _______(SPH-1), Numbers of Historical Hurricanes Affecting Current PEF Service Territory by Decade and by Maximum SSI Wind Speed in PEF Service Territory;
- Exhibit _______(SPH-2a), Landfall Milepost Map;

- Exhibit _______(SPH-2b), Comparison of Protection Afforded by $50m and $15m Annual Accrual Against Potential T&D Storms Damage From a Single SSI 1 Landfall at Milepost;
- Exhibit _______(SPH-2c), Comparison of Protection Afforded by $50m and $15m Annual Accrual Against Potential T&D Storms Damage From a Single SSI 3 Landfall at Milepost;
- Exhibit _______(SPH-2d), Comparison of Protection Afforded by $50m and $15m Annual Accrual Against Potential T&D Storms Damage From a Single SSI 4 Landfall at Milepost;
- Exhibit _______ (SPH-3), Storm Reserve Fund Analysis Case Results-Two Year Recovery of Negative Balances;
- Exhibit ________(SPH-4), PEF Transmission and Distribution Asset Hurricane Loss Reserve Solvency Analyses, August, 2005.

These exhibits are true and accurate.

Q. Can you summarize Mr. Schultz's, Ms. Brown's, and Mr. Stewart's basic positions on PEF's proposed annual storm damage accrual amount?

A. Yes, Mr. Schultz, Ms. Brown, and Mr. Stewart all contend that PEF has overstated its requested annual storm cost accrual. These intervenor witnesses assume that ten to fifteen years of recent favorable hurricane loss history can and will be adequate to protect hurricane losses into the future. They also assume that expected annual damage ("EAD"), can be reliably calculated based on limited hurricane damage data, excluding SSI 3, 4 and 5 events, and they contend that such data is adequate to define what PEF's reserve accrual should be. Finally, these intervenor witnesses propose an annual accrual amount that does not consider the fund starting balance, target balance, or solvency criteria. Based on these principles, these witnesses propose that PEF's annual storm cost accrual should be $12.5 million, $15.2 million, and $10 million, respectively.

Q. Do you agree with these witnesses' positions and analyses?

A. No, I do not. Estimation of the loss potential due to hurricanes requires the estimation of all possible hurricane events and the estimation of the damage done to assets at risk. This process establishes the magnitude of damage and the probability of its occurrence. In addition, estimates can and should be made of the expected annual damage. This analytic process is termed "loss analysis." Calculating an actual or simulated expected annual storm damage amount that selectively excludes any possible damage events, whether large and infrequent or small and frequent, is neither meaningful nor appropriate. Any reliable estimate of the expected annual damage (EAD) to which PEF is exposed from hurricanes must include the most complete and full damage distribution that can be determined both from actual experience and from simulated possible damage.

Hurricane events and damage occur in somewhat random processes, subject to chance. Over any given time sample, some years may experience no damage and others greater damage. Therefore, in developing expected annual damage estimates, the most reliable methodology is to utilize the longest, most complete historical record available. Since Florida's recorded hurricane history is just over 100 years old, insurers rely on simulation modeling to extend this "known" history into thousands of simulated years for the purpose of estimating likely damage. The simulated expected annual damage to PEF's system is the best estimate of the annual damage considering all possible future hurricanes; not just arbitrarily defined "normal" damage events as proposed by Mr. Stewart and implied by Mr. Schultz and Ms. Brown when they eliminate damage from 2004 as "extraordinary."

Q. Does the model that you used in your analysis of PEF's potential hurricane risk exposure utilize all the factors that you just discussed?

A. Yes. The Florida Commission on Hurricane Loss Projection Methodology (FCHLPM), an independent panel of experts that evaluates computer models and actuarial methodologies for projecting hurricane losses, goes to great lengths to ensure that all models used in the State for insurance rating purposes appropriately capture the full range of the hurricane hazard. The ABS Consulting USWIND™ model used to calculate PEF's expected annual damage is one of only four models evaluated and determined acceptable by the FCHLPM for projecting hurricane loss costs.

Q. How do you respond to intervenor arguments that PEF's hurricane damage experience over the past 10 years has been relatively minimal?

A. The intervenor witnesses argue that the average annual hurricane damage to PEF'S T&D assets over the past ten years is about $2 million when the damage from the hurricanes of 2004 is excluded. They contend that the hurricanes exclusive of the 2004 season are "normal" hurricanes and that all other events beyond $2 million per year in damage are extraordinary. What these witnesses fail to recognize, however, is that PEF has experienced a favorable decade (1990 to 1999) of hurricane storm history, consisting of a few small storms and small losses. There were no hurricanes with strong SSI 2 to SSI 4 winds that made landfalls near PEF's service territory during this period. Exhibit ___ (SPH-1) shows the number of historical hurricanes that have affected PEF's service territory over a 100-year history. Hurricanes with wind speeds defined by SSI intensities 1 through 3 are shown. On average, three and a third hurricanes per decade have affected PEF territory with sustained wind speeds in excess of 74 mph. The decades of the 1920s, 1940s and 1960s experienced an above average number of events. The decades of the 1970s, 1980s and 1990s experienced below average numbers of events. The 1990s have had the lowest number of hurricane force storms in PEF territory since the decade of the 1900s. The decade of the 2000s is only half through and there have been more than the 100-year average numbers of events with hurricane force winds. Therefore, characterization of PEF's hurricane experience over the 1990s, which was below average in number, consisting of one SSI-1 event, as "normal" is inaccurate and misleading.

Q. What is your assessment of the intervenor witnesses' positions on PEF's hurricane exposure risk?

A. The intervenor recommendations that $2 million should be considered a representative sample of the expected annual damage to PEF assets would only be acceptable if PEF's management and the Commission are willing to speculate that PEF's recent good luck over a brief, selective storm period considered by Mr. Schultz and other witnesses will continue. However, over the 100-year history, hurricane landfalls and damaging events have occurred much more often than in the last 10 years. Also, there is a growing body of evidence suggesting that the North Atlantic Oscillation (NAO) and the El Niño or Southern Oscillation (ENSO) are important climate variables in modulating hurricane return periods. The damage estimated in the ABS Consulting Rapid Update Study assumes the average hurricane activity over the century. If you accept the opinion that changes in the ENSO and NAO variables indicate we have entered a more active period for hurricane formation like the 1920s and 1940s, PEF may expect to experience higher than average damage to T&D and other assets over the next several years and the ABS Consulting damage estimates could understate the actual risk going forward.

Q. Is there any risk to PEF if the Commission adopts one of the three different intervenor recommendations on the amount of PEF's annual accrual for the storm reserve?

A. Yes. The annual accrual levels suggested by the intervenors present a much greater likelihood of reserve dissolvency over the five-year period of accrual that they recommend. This is so because the intervenor witnesses have not considered the performance of the storm reserve at their respective recommended annual accrual levels.

Once an appropriate estimate of the potential for hurricane damage is established, a cash flow analysis is required to determine an appropriate level of funding and acceptable performance of the Storm Reserve to meet acceptable levels of protection against some, but not all, storms along with an acceptable likelihood of solvency of the Reserve. A solvency analysis provides a tool for management and policymakers to determine the performance of the Storm Reserve and to test whether annual accrual amounts meet their objectives. The performance and solvency over time of the Storm Reserve must consider an annual accrual along with a starting balance and a working target balance within some time frame. With rate stability as a policy objective, the question is what Storm Reserve balance should PEF seek to achieve and how quickly should it be reached to provide the desired stability in rates? Once a proper Storm Reserve balance is determined and achieved, an accrual that equals the expected annual damage will maintain this level in the Storm Reserve.

The ABS Consulting Solvency Analysis is a cash balance analysis starting with some initial balance, which is zero in this case. An annual accrual is added to the cash balance, and annual storm damage is simulated consistent with the Storm Loss Analysis for each of the five years. The storms are randomly simulated, but over a long period of time, they match the expected annual damage to PEF's system from the Loss Analysis for each of the five years in the solvency simulations.

For example, given that the expected annual damage is $15.1 million per year, if the Storm Reserve is funded at $15.1 million per year over a long period of time, the expected annual damage equals the annual accrual and the Reserve will not gain or lose value. At a balance of $0, any storm damage will have the effect of causing insolvency whenever it occurs. Therefore, with a starting balance of zero, the expected balance of the Reserve would always hover around zero without recovery of any negative Reserve balances. Likewise, if the beginning Storm Reserve balance is $150 million or $250 million, the balance will not grow if the annual accrual equals the expected annual damage. Rather, it will fluctuate around the beginning balance.

The future performance of the Storm Reserve cannot be established without a financial simulation analysis that includes both the annual accrual and the beginning balance of the Storm Reserve. The intervenors do not consider the starting Storm Reserve balance in making their recommendations. Only Mr. Schultz proposes a target Storm Reserve balance of $50 million within 5 years. However, Mr. Schultz and Ms. Brown both assume that annual damage will remain at around the historically low range of $2 million per year for the next five years allowing the fund to grow to $50 million at the end of 5 years.

By way of example, ABS Consulting has analyzed the performance of the Storm Reserve assuming the accruals recommended by Ms. Brown. Exhibit ___ (SPH-3), titled Storm Reserve Fund Analysis Case Results, demonstrates that the $15 million annual accrual recommended by Ms. Brown results in a 54% chance of insolvency within the five-year period with a recovery of negative balances over a two-year period. $15 million is the largest of the three annual accruals proposed by intervenors ($10 m, 12.5m and 15.2m). A $15million accrual results in an expected $25 million Storm Reserve balance at the end of five years. There is a 54% chance of insolvency within the 5 year simulation and a 20% chance of fund insolvency at the end of 5 years.

The $10 and $12.5 million annual accruals recommended by Mr. Stewart and Mr. Schultz would result in a greater chance of insolvency and smaller expected balances. These accruals are contrasted with PEF's recommended annual accrual of $50 million, that has a 12% chance of insolvency within five years. At the end of five years, the expected balance in the Reserve is $183 million with a two year recovery of negative balances and there is a 2% chance of fund insolvency at the end of 5 years.

Q. Have you done anything to compare the levels of insolvency protection afforded by varying the levels of potential storms?

A. ABS Consulting performed an analysis of a full suite of possible hurricanes that could make landfall and cause damage to PEF's T&D assets. Exhibit _____ (SPH-2b) shows the frequency-weighted average T&D damage from single SSI-1 storms, the least intense on the Saffir-Simpson Hurricane Scale, that could make landfall at specified mileposts along the Florida coast. Single SSI-1 landfalls on the Gulf coast near mileposts 1160 to 1210, have a mean (average) T&D damage of approximately $60 million. Single SSI-1 landfalls on the Atlantic coast near mileposts 1620 to 1640, have an average T&D damage of nearly $40 million.

For a $15 million annual accrual the expected Reserve balance of $25 million after five years determined from the Solvency Analysis is adequate to cover some, but not all of the SSI-1 T&D damage in PEF's service territory. Exhibit No. ____ (SPH-2b), also shows that $50 million annual accrual, which results in an expected Reserve balance of $183 at the end of 5 years, would provide adequate funds for all SSI-1 T&D storm damage. Exhibit No. ____ (SPH-2c) shows that the expected Storm Reserve balance at the end of five years for a $50 million accrual and expected Reserve balance of $183 million at the end of five years will be adequate for some but not all SSI-3 storms. It will cover all landfalls north of milepost 1160 and south of milepost 1220. The $50 million accrual would cover most SSI-3 landfalls except the greatest damage in the near mileposts 1160 to 1220 where it would cover about three quarters of the damage in excess of $200 million.

Similarly, for SSI-4 storms, the $183 million balance expected Storm Reserve balance covers a little less than half of a strike between mileposts 1160 to 1220, where damage averages in excess of $350 million; the highest asset concentrations in PEF's service area.

Even if the Storm Reserve, as assumed by Mr. Schultz, were to reach a $50 million balance as the result of five years of very favorable hurricane experience, $50 million can be seen in Exhibit No. ___ (SPH-2c) to provide only enough funds to cover SSI 3 hurricanes making landfall in the least concentrated, extreme northern and southern areas of PEF's service territory. The annual accrual levels recommended by witnesses Brown, Schultz, and Stewart do not even cover "normal" levels of storm damage. In fact, the annual accrual levels proposed by these witnesses along with the current zero Storm Reserve balance results in small expected Storm Reserve balances that would not cover T&D damage over any sustained period of time from anything but the smallest SSI-1 storms.

Q. How do you respond to Mr. Stewart's contention that the balance in the storm reserve would have been $515 million after the 2004 hurricane season if the accrual had been $50 million beginning in 1990 with the recovery of negative balances within two years?

A. In 1990, PEF did not need a $50 million annual Storm Reserve accrual because the Storm Reserve balance was $2.9 million and growing due to a favorable storm experience during the 1970s, 1980s and 1990s. Exhibit No. ____ (SPH-1) shows the historical numbers of hurricane landfalls of intensities SSI 1 through 5 that would have affected PEF's current service territory over the 104 year Florida hurricane history by decades. This exhibit demonstrates that the historical experience is highly variable and that the decades of the 1970s through 1990s represent a favorable lower frequency of hurricanes compared to earlier periods such as the 1920s, 1940s and 1960s.

PEF had fewer customers and PEF's asset base at risk was also much smaller in 1990. In addition, PEF could insure transmission and distribution assets until 1993, when insurance became unavailable and therefore didn't need a large Storm Reserve balance.

Viewed retrospectively, over the period from 1990 through 2004, however, PEF did need a higher annual accrual. This is borne out by the estimate of the historical annual damage of $33 million performed by Ms. Brown using a limited 10 years of loss history. The estimate of the expected annual damage (EAD) of $15.1 million is more representative of the much longer 100 year history, reflecting both decades of more and less favorable hurricane experience. Mr. Stewart's analysis demonstrates retrospectively, (based on the limited experience over the period from 1990 to 2004) that an annual accrual of $30 million would have been adequate to maintain a solvent Storm Reserve.

Q. Do you have any concluding remarks regarding your testimony?

A. Yes. With a current zero Storm Reserve balance, PEF has requested a $50 million annual accrual, approximately $15 million for expected annual damage plus $35 million to build the Storm Reserve up to a working balance of $183 million that can fund for most non-catastrophic storms. The ABS Consulting's Solvency Analysis shows there is value in setting the annual accrual at a level higher than the expected annual damage. Assuming an annual accrual of $15 million and a two-year recovery of negative balances, close to the expected annual damage, 54% of the time PEF's Storm Reserve will go insolvent within 5 years. If the annual accrual is $50 million and recovery of negative balances occurs over a two-year period, the likelihood of insolvency within the 5 years goes down to 12%. Therefore, the value of accruing at a level higher than the expected annual damage until PEF's Storm Reserve reaches some substantial balance is a more rapid growth of the Reserve balance, a reduction in volatility, and a reduction in the likelihood of insolvency of more than 75% over the period. This reduction in volatility would be seen in a reduced frequency of special assessments and a reduction of the levels of borrowing costs when the Storm Reserve does become insolvent from extraordinary storm years.

If the PEF Storm Reserve balance had been zero at the beginning of the 2004 storm season, the current deficit from storm restoration would be the full $350 million in uninsured damage. Providing a positive target balance for the Storm Reserve reduces the rate volatility and results in less frequent special assessments for cost recovery.

I also would like to mention that this month, we have just completed PEF's full Transmission and Distribution Hurricane Loss Reserve Solvency Analysis. A copy of that analysis is included with this testimony as Exhibit No. __(SPH-4). Based on this full study, PEF could support a request for a $75 million annual accrual to the Storm Damage Reserve. This fact shows that PEF's request for a $50 million accrual is clearly conservative and very reasonable.

Q. Does this conclude your testimony?

A. Yes.

REBUTTAL TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name.

A. My name is Javier Portuondo.

Q. Did you submit direct testimony in this case on April 29, 2005?

A. Yes, I submitted direct testimony that addressed the development of Progress Energy Florida, Inc.'s ("PEF's" or "the Company's") Minimum Filing Requirements (MFRs) from its 2005 - 2006 budget process and the various ratemaking adjustments described and supported in my testimony.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond to certain assertions and positions contained in the testimony of Florida Retail Federation ("FRF") witness Sheree Brown, Office of Public Counsel ("OPC") witnesses Donna DeRonne and Hugh Larkin, White Springs Agricultural Chemicals ("White Springs") witness Michael Gorman, and joint OPC and Florida Industrial Power Users Group ("FIPUG") witness Jacob Pous. My responses will address, in the order listed, the following areas of my direct testimony and sponsored MFR schedules where the intervenor witnesses have raised issues:

- Depreciation Reserve Variance
- Nuclear Decommissioning Reserve
- Fossil Dismantlement Expense
- Gain on Sale of the Winter Park Distribution System
- PEF's Adjustment to the Equity Component of Capital Structure

- Electric Plant In Service
- Construction Work In Progress in Rate Base
- Plant Held for Future Use
- Last Core Nuclear Fuel and End-of-Life Material & Supplies Reserve
- Working Capital Adjustments
- Deferred Income Taxes
- Amortization of Rate Case Expense
- Other Net Operating Income Adjustments

In addition, I will provide accounting and regulatory support for the updated sales forecast and revised cost of service presented in the rebuttal testimony of John B. Crisp and William Slusser. I will do so through an exhibit to my testimony that summarizes and incorporates Mr. Crisp's updated forecast and Mr. Slusser's jurisdictional cost allocation into certain key MFR schedules which utilize information from the sales forecast as an input.

Q. Have you prepared any exhibits for use in conjunction with your rebuttal testimony?

A. Yes. . I have prepared or sponsored the preparation of the following exhibits to my testimony:

- Exhibit No. ____ (JP-12), Analysis of Cost of Service Associated with Winter Park.
- Exhibit No. ___ (JP-13), Impact of Revised Sales Forecast and Winter Park Treated as Wholesale.
- Exhibit No. ___ (JP-14), Proposed Adjustments 2006 Test Year: System and Retail.

- Exhibit No. ___ (JP-15), Payroll and Payroll Taxes.
- Exhibit No. ___ (JP-16), EOL Nuclear M&S and Last Core Nuclear Fuel.
- Exhibit No. ___ (JP-17), Storm Impact.
- Exhibit No. ___ (JP-18), Revised Schedule A-1.
- Exhibit No. ___ (JP-19), Revised Schedule D-1a.
- Exhibit No. ___ (JP-20), Progress Energy Florida Plant in Service Balance.

These exhibits are true and accurate.

<u>**Depreciation Reserve Variance**</u>

Q. Intervenor witnesses Larkin and Pous have cited or quoted from a number of Commission orders in support of their proposition that the depreciation reserve variance calculated by PEF should be refunded to customers over a substantially shorter period than the average remaining life of the related assets. Would you provide your assessment of the regulatory policy described in these Commission orders in terms of consistency with the witnesses' proposition?

A. My review of the Commission orders referenced by Mr. Larkin and Mr. Pous has shown that they have been either very selective in using the portions of those orders which, in the absence of context, appear to support their radical proposal, or they have simply misconstrued the orders in general. The following is brief discussion of each of the Commission's depreciation orders referenced in the testimony of these two witnesses.

- <u>Order PSC-02-0655-AS-EI</u>, issued May 14, 2002, approving the Stipulation and Settlement in PEF's last rate case. The Commission in this order approved a settlement between the parties that would result in a rate reduction of $125 million annually to customers. In addition to providing a $125 million annual rate reduction to customers, the settlement approved by the Commission also provided for a reduction in PEF's depreciation expense. Mr. Pous claims this demonstrates the lack of a "rigid adherence to 'remaining life' concepts ... ." (Pous Testimony, page19, lines 19-20.) In actuality, it demonstrates no such thing. To the contrary, the Commission required PEF to file an abbreviated depreciation study, which was performed on an average remaining life basis, to ensure that the reduction in depreciation expense was consistent with sound depreciation theory and not a departure from remaining life depreciation results. This was confirmed again by PEF's current depreciation study, which continues to show that going-forward depreciation rates should be lower than the Company's previous rates approved in 1997. Further, OPC, Mr. Pous' client, agreed in paragraph 10 of the settlement agreement approved by the Commission to the use of remaining life depreciation to address that part of the depreciation expense that was suspended under the agreement when the agreement expired.

- Order No. 19901, issued August 30, 1988, regarding Gulf Power's depreciation study. The reference to this order in Mr. Pous' testimony provides an example of the distortion that can occur when context is ignored. The context in which Order No. 19901 was issued begins almost four years earlier with the issuance of Commission Order No. 13681 on September 17, 1984, which addressed Gulf Power's request for approval of new depreciation rates. Prior to this request, Gulf's depreciation rates had been based on the "whole life" methodology but, pursuant to Commission rule 25-6.0436(7), Gulf's then-current depreciation study was required to be based on the average remaining life methodology. This one-time transition from whole life to remaining life depreciation produced a significant reserve deficiency, which provided the Commission an opportunity to articulate its policy on reserve variances in its 1984 order, Gulf's first depreciation order under the remaining life methodology. The following quotation from Order No. 13681 expresses this Commission policy:

> "While it is possible to make the reserve correction of these accounts through the new depreciation rates allowed for embedded plant, we have chosen to amortize this reserve deficit over the composite <u>remaining life</u> of the associated investment. ... We are ordering a 19-year amortization schedule for use in recovering the reserve deficit associated with the Transmission, Distribution and General Plant accounts." (Emphasis added.)

Ignoring this statement of general policy by the Commission on the treatment of overall reserve variances, Mr. Pous instead refers to an issue in Gulf's next depreciation study regarding a surplus in one particular reserve account related to the Job Development Investment Tax Credit (JDIC). In Order No. 19901 cited by Mr. Pous, the Commission simply authorized a reserve account transfer which allowed the account surplus created by the implementation of the JDIC to be used as a contribution toward the 19-year remaining life amortization of the overall reserve deficiency that the Commission established in Order No. 13681 from Gulf's prior depreciation proceeding.

- <u>Order PSC-01-2270-PAA-EI</u>, issued November 19, 2001, regarding the depreciation study for the Marianna Division of Florida Public Utilities

Company. Far from supporting the severe departure from remaining life depreciation principles that witnesses Pous and Larkin espouse, this case deals with corrective action taken by the Commission to remedy a negative reserve balance created when specific plant investments, which in fact had not been made, were removed from a reserve account. As in the discussion of Order No. 19901 above, the Commission simply authorized a reserve transfer which applied a surplus from another reserve account to offset the deficiency in the corrected plant account. Importantly, the surplus was not flowed back to ratepayers through a foreshortened amortization, as the intervenor witnesses propose, but instead was used to maintain the utility's depreciation rates based on remaining life principles.

- Order No. 19438, issued June 6, 1988, regarding a change in Tampa Electric Company's depreciation rates. In this order, as in the 1988 Gulf depreciation order discussed above, the Commission was addressing a prior order in which it had found that the most efficient mechanism for addressing the unique depreciation impact on customers from implementation of the JDIC was through a depreciation reserve adjustment. As before, the adjustment was well below the threshold of policy making, but was rather the application of a mechanism, or tool, tailored to address a specific situation created by a federal tax initiative. Other specialized amortization schedules approved by the Commission in this order were designed to address unrecovered investment in specific assets that were being taken out of service earlier than would normally be the case if not for a change in technology, federal and state regulations, or other equipment-specific issues.

- Order No. 14929, issued September 11, 1985, establishing new depreciation rates for GTE. One might have expected depreciation experts such as the intervenor witnesses to appreciate the unique circumstances of the telephone and communication industry as a whole regarding the difficulty in estimating the useful lives of depreciable assets because of premature obsolescence resulting from, as the Commission put it, "substantial developments in the area of technology and competition". It is virtually common knowledge that the telephone industry has and continues to be plagued with technical obsolescence that drives significant retirements much earlier than would have been initially expected, a problem that is exacerbated by the anticipation of wide-spread competition. As the Commission stated in the cited order, "we believe it is our duty and in the best interest of the Company and ratepayers to move forward with represcription of the Company's intrastate depreciation rates." The circumstances and facts in this case, and the regulatory response required, have no relevance to PEF's current depreciation study.
- Order No. 22115, issued October 31, 1989, regarding the establishment of new depreciation rates for City Gas Company. The intervenor witnesses have again ignored the context in which this order was issued. Instead, they have focused on the implementation specifics of a Commission policy without regard to the policy itself. In this case, the policy that gave rise to the recovery schedule discussed in Order No. 22115 was addressed in Order No. 13538 issued in the predecessor proceeding. In that order, the Commission stated: "We are ordering two amortization schedules for use in recovering the reserve deficit. That portion of the deficit that is attributable to changes in prospective life and salvage values is to be amortized over the composite

remaining life of the embedded plant, which is estimated to be 24 years. That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5-year amortization period for this portion of the deficit." The policy described by the Commission in which reserve variances attributable to changes in prospective life and salvage values are amortized over the assets' remaining life is instructive, since this is precisely the kind of changes that brought about the reserve variance in the Company's current depreciation study.

- Order No. PSC-97-0499-FOF-EI, issued April 29, 1997, regarding Florida Power & Light's proposal for plant life extensions. Like many of the other orders quoted in Mr. Pous' testimony, this order addresses a specific deficiency associated with a specific facility. It should be clear at this point that it is not unusual for the Commission to establish accelerated amortization schedules to address equipment or facility-specific reserve issues. It is another thing entirely to suggest that amortization be accelerated well ahead of the composite remaining lives of all depreciable equipment and facilities to address the non-specific, overall net variance from every reserve account.
- Order No. PSC-93-1839-FOF-EI, issued December 27, 1993, regarding the depreciation study for the Marianna Division of Florida Public Utilities Company. Not surprisingly, Mr. Pous has taken a statement from the Commission's order out of context. He quotes from the order as follows: "According to our Staff such deficiencies should be recovered as fast as possible, unless such recovery prevents the Company from earning a fair and reasonable return on its investment." This statement, of course, reflects the

opinion of the Commission staff at that time, not the Commission itself. Suffice it to say that the Commission did not order a change in the rates of customers as a means to accelerate the write-down of this reserve variance, as the intervenor witnesses have proposed in the present case. Instead, the Commission employed the practice of reserve transfers to address the matter in that case, as it has done in many of the cases cited by the intervenor witnesses.

- Order No. 13427, issued June 15, 1984, in the Commission's investigation of the appropriate accounting and ratemaking treatment of nuclear power generators. This order has no relevance to a discussion regarding the treatment of depreciation reserve variances. In the order, the Commission states: "Further, our principle purpose in the case was not to correct deficiencies in revenue recovery, but to correct an accounting and ratemaking problem. We determined that the current method of recovery of decommissioning costs was deficient from both an accounting standpoint and a ratemaking standpoint." The issue of reserve variances in PEF's depreciation study is neither an accounting nor a ratemaking problem, since the Commission satisfactorily dealt with the accounting and ratemaking aspects of this issue in many proceedings over the years using sound remaining life depreciation principles. Moreover, the statement quoted by Mr. Pous concerns the then-pending question of whether the Commission should establish a funded or unfunded nuclear decommissioning reserve. This is not an issue pending before the Commission in this proceeding.

Finally, I reference the orders directly below in summary fashion because they are unremarkable and repetitive of the comments and points that I make above. Said simply, the orders below add nothing to the Commission policy and practices disclosed by the other cases cited by the intervenor witnesses that I have discussed previously.

- Order No. 18736, issued January 26, 1988, regarding Untied Telephone's request for accelerated amortization.
- Order No. 23833, issued December 4, 1990, regarding Alltel Florida's request for depreciation rates.
- Order No. 24004, issued January 22, 1991, regarding Gulf Telephone's 1990 depreciation study.
- Order No. 12290, issued July 22, 1983, regarding Southern Bell Telephone's represcription of depreciation rates.
- Order No. 12857, issued January 10, 1984, regarding United Telephone's new depreciation rates.
- Order No. 12864, issued January 12, 1984, regarding North Florida Telephone's revision of depreciation rates.
- Order No. 18642, issued January 4, 1988, regarding Gulf Telephone's 1987 depreciation study.

Q. What conclusion should be drawn from an analysis of the Commission orders cited by the intervenor witnesses to support their proposal to accelerate PEF's overall reserve variance rapidly, without regard to the composite remaining lives of the underlying plant assets?

A. The cases referenced by intervenor witnesses Larkin and Pous are not inconsistent with, and in many instances actually support, PEF's remaining life treatment of its depreciation reserve variance. Specifically, these cases make clear that the

Commission's use of intra-reserve account transfers to address specific equipment or facility reserve issues is entirely different from and unsupportive of the intervenor witnesses' proposal to accelerate the amortization of the non-specific, total net reserve variance, without regard to the composite remaining lives of the depreciable equipment and facilities.

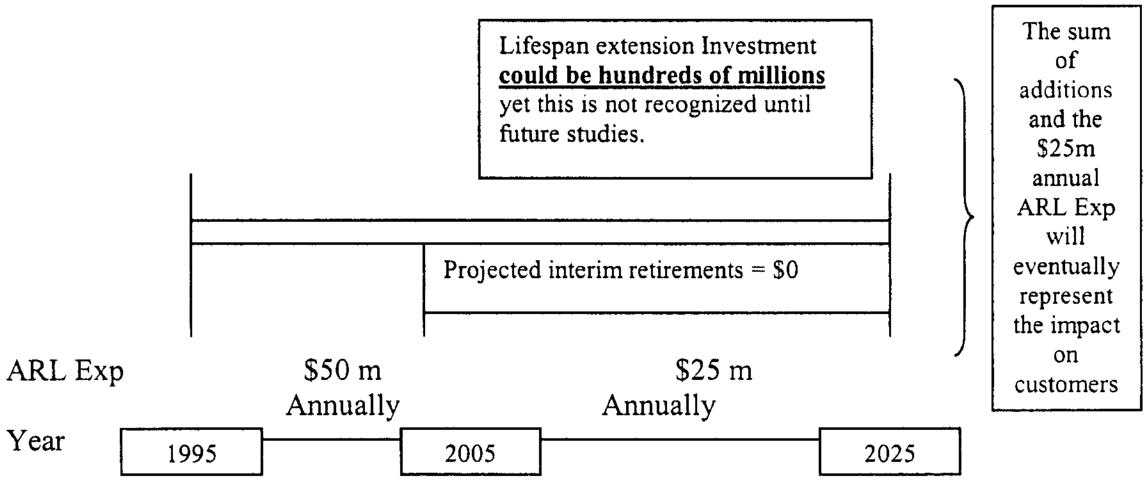
Moreover, the witnesses' proposal is plainly contrary to the Commission's policy, as clearly articulated in Order No. 13681, that a reserve variance which is "attributable to changes in the prospective life and salvage values is to be amortized over the composite remaining life of the embedded plant." This policy clearly supports, if not requires, PEF's remaining life treatment of the reserve variance in this case, since the Company's entire reserve surplus is the direct result of changes to the prospective lives and salvage values of the embedded plant.

Q. Do you agree with the intervenors' assertion that the "theoretical reserve" represents an over collection from customers?

A. No. Rates charged to customers are based on the expected lifespan of the facilities dedicated to electric service. The fact that over time, a facility that was expected to be in operation for 20 years may now be able to continue operating for 30 years does not mean that customers have over paid. The use of the "theoretical reserve" is a poor test for such a determination because it ignores the future investment that will be necessary to permit those facilities to continue to operate an additional 10 years. The theoretical calculation only utilizes the current level of investment and the level of interim retirements projected for those assets. It ignores the major investment that may be required 5 or 10 years out in order to achieve this life extension as well as interim additions related to the interim retirements.

Therefore, it is an incomplete view of the impact of a facilities' life extension. This can be illustrated below:

Example:



Orig Life 20 yrs. New life 30 yrs
Invest. $1 billion
Accum. $0 Accum Bk. $500 million
Theoretical <u>$333 million</u>
Variance <u>$167 million</u>

The example above demonstrates that customers during the first 10 years have not over paid. The payments on which rates were set are based on the service received from assets operating during the most efficient period of their lifespan. The change in the ARL expense ($50m to $25m) resulting from the ARL calculation under the intervenors' application of the "theoretical reserve" ignores the impact on future customers necessary to achieve the benefits of a longer useful life that intervenors wish to give to past customers. Future customers will need to cover the improvements both necessary to address the interim retirements considered in the ARL calculation as well as those capital improvements directed specifically at driving a longer useful life from these facilities. The impact on future customers will be greater than past customers under intervenors' proposals because they have to cover the costs over a shorter period of time. So, the application of the Commission policy to address depreciation variances over the remaining life of the investment serves to equalize the impact on customers and provide intergenerational equity.

Nuclear Decommissioning Reserve

Q. The testimonies of White Springs witness Gorman and OPC witness Pous urge the Commission to require the entire balance of one of the two trust funds established by PEF's nuclear decommissioning trust instrument to be withdrawn and refunded to customers over a five-year period. Please comment on this proposal.

A. I won't belabor my response with a description of the lengths to which this Commission has gone to ensure that nuclear decommissioning funds are insulated from proposals like Mr. Gorman makes in his testimony. Instead, I will address the results of this effort by the Commission, which, in PEF's case, is the nuclear decommissioning trust agreement the Company entered into pursuant to the Commission's mandate for the safeguarding of nuclear decommissioning funds. First, however, I will briefly describe why Mr. Gorman's and Mr. Pous' proposals fail to square with the rules of the Nuclear Regulatory Commission (NRC).

The NRC's comprehensive rules regarding the obligations and responsibilities of nuclear plant licensees make it clear that once funds are placed in a decommissioning trust, disbursements of the kind proposed by Mr. Gorman are impermissible. An example of the NRC's restrictions of fund disbursements is found in 10 CFR § 50.75(h)(2) which states:

> Disbursements or payments from the trust, escrow account, Government fund, or other account used to segregate and manage the funds, other than for payment of ordinary administrative costs (including taxes) and other incidental expenses of the fund (including legal, accounting, actuarial, and trustee expenses) in connection with the operation of the fund, <u>are restricted to decommissioning expenses or transfer to another financial assurance method acceptable under paragraph (e) of this section until final decommissioning has been completed.</u> (Emphasis added.)

In addition, 10 CFR § 50.82(a)(8)(i) specifies three conditions, each of which must be satisfied, for the use of decommissioning trust funds. Directly on point is subsection (A), which states that such funds may be used by licensees if "the withdrawals are for expenses for legitimate decommissioning activities within the definition of decommissioning in 50.2." Without quoting the lengthy definitions in section 50.2, suffice it to say that the use of the trust funds proposed by Mr. Gorman and Mr. Pous is not a "legitimate decommissioning activity."

Moreover, even if the NRC's rules did not prohibit the use of decommissioning funds for a utility rate refund as proposed by Mr. Gorman and Mr. Pous, the trust agreement entered into by PEF in compliance with the Commission's external funding requirements does. In this regard, Section 1.02 of the agreement states: "Purposes of the funds. The Funds are established for the exclusive purpose of providing funds for the decommissioning of the Unit [CR3]." Thereafter, Section 2.01 adds specificity to the "exclusive purpose" provision by stating:

> Use of Assets. The assets of each Fund shall be used exclusively (a) to satisfy, in whole or in part, any expenses or liabilities incurred with respect

to the decommissioning of the Unit, including [numerous examples omitted], (b) to pay the administrative costs and other incidental expenses of each Fund, (c) to make investments (including common trust funds) as directed by the investment manager(s) pursuant to Section 3.03(a) or the Trustee pursuant to Section 3.03(b), and (d) to be distributed upon termination of this Agreement pursuant to Article 6 hereof.

Finally, and to similar effect, the Special Terms contained in Exhibit A to the trust agreement provides the following restrictions:

Section 3. Limitations on Use of Assets. The assets of the Qualified Trust Fund shall be used exclusively as follows:

(a) To satisfy, in whole or in part, the liability of the Company for Qualified Decommissioning Costs through payments by the Trustee pursuant to Section 2.02 of the Agreement; and

(b) To pay the administrative costs and other incidental expenses of the Qualified Trust Fund; and

(c) To the extent the assets of the Qualified Trust Fund are not currently required for (a) and (b) above, to invest the assets of the Qualified Trust Fund.

Individually and collectively, the above restrictions demonstrate conclusively that PEF's decommissioning trust funds are, as they should be, beyond the reach of those who would use these funds for purposes other than the singular purpose for which they are intended.

Fossil Dismantlement Costs

Q. White Springs witness Gorman also faults PEF's fossil plant dismantlement cost study because it does not include the value of land on which a plant is situated in the net salvage value of the plant to be dismantled. Do you believe this to be a valid criticism?

A. Not at all. Mr. Gorman's has based his assertion that the value of land should have been included in PEF's dismantlement study on a novel concept of salvage that I find to be poorly conceived and supported. One does not dismantle land and, in the same sense, one does not salvage land. Salvage involves property that consists of the equipment and material associated with the plant subject to dismantlement. In the simplest terms, it involves the kind of property that can be put on the truck of a salvage contractor. Therefore, since land is not salvage, it follows that the value of land is not salvage value.

This layman's concept of the distinction between land and salvage is borne out by the definitions in rules promulgated by the relevant regulatory agencies. For example, the FERC Uniform System of Accounts defines salvage value as follows:

> Salvage value means the amount received for property retired, less any expense incurred in connection with the sale or in preparing the property for sale; or, if retained, the amount at which the <u>material</u> is charged to <u>Material and Supplies</u>, or other appropriate amount. (Emphasis added.) (18 CFR, Part 101.)

Even more significantly, it is evident from this Commission's rule on fossil plant dismantlement that land is not the subject of dismantlement. This can seen in the definition of "dismantlement" and "dismantlement costs" found in Rule 25-6.04364(2), F.A.C.

(b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the materials and equipment that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or usable condition.

(c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service. (Emphasis added).

These definitions confirm what would be commonly understood in any event; namely, that the subject of dismantlement is material and equipment, and that the value in question is the salvage attendant (*i.e.*, related to, associated with, or accompanying) the dismantlement process of removing and disposing plant (*i.e.*, materials and equipment), and restoring the site. Land is simply not a part of the dismantlement process in general or salvage in particular, and its value is not a component of dismantlement costs nor the dismantlement studies that identify these costs.

Gain on Sale of the Winter Park Distribution System

Q. Are you familiar with PEF's recent sale of its electric distribution system in Winter Park to the City?

A. Yes I am. I provided testimony in the Winter Park valuation arbitration and was involved in finalizing the closing on the Winter Park sale.

Q. What was the total purchase price paid by the City for PEF's Winter Park system?

A. The total purchase price was $43,072,447, which consists of the following categories:

Equipment and fixtures:	$8,218,447
Stranded costs:	$7,689,000
CWIP true-up:	$2,800,000
Half joint-use attachment inventory:	$15,000
Real estate and easements:	$10,000,000
Going concern:	$12,000,000
Separation and reintegration:	$2,000,000
Maps, manuals, records:	$350,000
Total	$43,072,447

Q. Will you please briefly explain each of these categories that comprise the total purchase price for PEF's Winter Park system?

A. Certainly. As the name suggests, the equipment and fixtures category is the price for the actual electrical distribution equipment sold to Winter Park. The stranded costs award was made pursuant to FERC Order 888 to reimburse PEF for its cost in generation assets built or purchased, in part, to serve customers in Winter Park. The CWIP true-up was a payment to PEF for construction work in progress that was not included in the equipment and fixtures category noted above.

The joint-use attachment inventory payment was to reimburse PEF for half the cost of a field inventory conducted by PEF to account for the joint use attachments in Winter Park, which was required to facilitate the system transfer.

The real estate and easement category involves a real property parcel and the Company's distribution easements within the City, together with an assemblage value for the package sale of the easements. The going concern payment was made to compensate PEF for the lost income earning potential for the distribution system that was sold to Winter Park. This was determined in the arbitration by the difference in earning potential the City received from buying the electric distribution system from PEF rather than building its own electric distribution system within the City.

The separation and reintegration payment compensated PEF for its costs to physically separate the Winter Park distribution system from the remainder of PEF's distribution system and to reconnect and reintegrate its remaining distribution system outside the City. Lastly, the maps, manuals, and records payment compensated PEF for certain system maps, distribution service manuals, and customer records provided to the City as part of the system transfer.

Q. Are you familiar with the testimony of Ms. Brown and Ms. DeRonne regarding the sale of PEF's Winter Park distribution system to the City?

A. Yes I am.

Q. Can you summarize Ms. Brown's testimony on this issue?

A. Ms. Brown contends that PEF has received a gain of approximately $29.8 million from the sale of its electric distribution system in Winter Park. She further contends that this gain should be paid to PEF's ratepayers by amortizing the gain over a five-year period, thereby reducing test year revenue requirements by $5.96 million.

Q. Does Ms. Brown recognize that any part of the Winter Park purchase price should not be allocated to PEF's ratepayers?

A. Yes, on page 48 of her testimony, Ms. Brown excludes the portion of the purchase price for separation and reintegration and CWIP and, by doing so, she recognizes that these items should be excluded from any proposed gain to be allocated to ratepayers because those payments were made to reimburse PEF for costs it incurred as part of the system transfer.

Q. Should Ms. Brown have excluded any other portions of the purchase price from the gain that she proposes to flow to PEF's ratepayers?

A. Yes, as its name suggests, the payment for stranded <u>costs</u> award was made to compensate PEF for costs caused by the system transfer, just like separation and reintegration costs that Ms. Brown excluded from her proposed gain amount. Furthermore, the payment Winter Park made to PEF for half the joint use inventory was designed to simply reimburse PEF for costs incurred in the system transfer which, using her own logic, Ms. Brown should have excluded the gain amount as well.

Q. Had Ms. Brown excluded these items, what would her total proposed gain amount have been?

A. $22,096,000.

Q. Is it PEF's position that this $22,096,000 gain should be allocated to ratepayers?

A. No. The entire purchase price, including the $22,096,000 gain using Ms. Brown's figures, should be allocated to the shareholders because it is their electric distribution system that was sold to the City of Winter Park, as I explain below and as this Commission has recognized in the context of the sale of other utility systems.

Q. Can you summarize Ms. DeRonne's testimony on this issue?

A. Yes. Like Ms. Brown, Ms. DeRonne contends that the gain on the Winter Park transaction should be provided to PEF's ratepayers over a five-year period. Unlike Ms. Brown, however, Ms. DeRonne states that she is unable to calculate the adjustment necessary to provide the gain to PEF's ratepayers.

Q. Do you agree with Ms. Brown and Ms. DeRonne that PEF has realized a gain that should be provided to PEF's ratepayers?

A. No, I do not. The proceeds from the Winter Park system sale do not constitute a gain on the sale of specific, isolated utility assets or parcels which, under Commission precedent, should be provided to PEF's ratepayers. Instead, any gain from the Winter Park system transaction should be allocated to PEF's shareholders, as Commission precedent also recognizes.

Customers pay for service, they do not invest in the Company and, therefore, they do not receive or hold any interest in the Company. They also take on none of the risks of success or failure of the Company's business by simply paying for the electric service they receive. On the other hand, the shareholders do invest in the Company, they do have an interest in the Company as a result, and they do assume the risk of success or failure of the Company's business. This fundamental distinction between the interests of customers and shareholders drives the determination that the gain (or loss) on the sale of the Company's electric distribution system within the City of Winter Park should be allocated to the Company's shareholders.

Q. Will you please explain what you mean when you refer to Commission precedent supporting the position that any gain from the Winter Park transaction should be allocated to PEF's shareholders?

A. Yes. First, it is important to note that there have been sales of <u>single (or multiple) isolated units</u> of utility property (such as pieces of equipment, parcels of land, or structures) where the Commission has amortized the gain on sale over five years and allocated the gain to ratepayers. However, when the Commission has addressed the sale of <u>entire utility systems</u>, the Commission has consistently attributed the gains on sale to the utility investors.

For example, in the case of <u>In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida</u>, Order No. PSC-03-1440-FOF-WS, issued December 22, 2003 in Docket No. 020071-WS, the Commission agreed with the utility that gains on the sale of water systems to the Cities of Maitland and Altamonte Springs, respectively, should be attributed to shareholders. The utility's expert in that case made a number of arguments that the Commission found to be "very persuasive." A summary of his key arguments follows:

1. The cost of service includes the cost of resources consumed or used during a given period of time. The Uniform System of Accounting then limits operating expenses to the costs of providing service and requires the sale of

systems to be recorded in income accounts reflecting gains or loss, thus, signifying shareholder's capital withdrawn from the utility.

2. Regulators allow utilities a reasonable return on capital for only original cost book values. Since book value is less than replacement value, ratepayers are shielded from price increases that might otherwise reflect the increased costs of replacement value. Neither depreciation nor return reflect the higher costs which investors face replacing these assets upon retirement, thus, this is a risk borne by shareholders.

3. Customers' rights cease with their payment for service received. Payments for service do not entitle ratepayers to receive any interest in the property of the utility serving them.

4. Investors bear the risk of success or failure of the business. This includes weather impacts, customer usage changes, management's ability to control costs, inflation, regulatory lag, etc., all of which will be reflected in the capital markets which regulators cannot control. Failure to allocate gains or losses on sales to investors will thus have adverse impacts on the utility's ability to raise capital at reasonable costs.

5. Commission rulings requiring ratepayers to bear the cost and risk of plant abandonments were distinguished because there was a finding of prudence; utilities bore the risk of loss on imprudent abandonments.

6. Commission rulings in electric utility cases were distinguished because the gains were associated with specific assets rather than the sale of facilities, service territory, and customers.

7. Whether a utility has uniform stand-alone rates is irrelevant because there is no relation of rates to any particular element of cost of service (i.e. customers only pay for service).

8. The payment of depreciation does not entitle ratepayers to the gain on sale if the depreciation booked by the utility was not in excess of the amount required to reflect the useful lives of the assets. The purchaser of the utility's assets is paying for the remaining useful life not for the value that has already been consumed.

9. Investors are risk averse and therefore would attempt to avoid the confiscation of capital by the assignment of gains to ratepayers. Allocating gains to shareholders does not allow the utility to recover more than the cost of service because the sale of assets is outside the cost of providing service.

In finding these arguments "very persuasive," the Commission specifically mentioned that customers pay for service only, that customers pay rates based on original cost rather than replacement cost value, and shareholders bear risk of regulatory lag. The Commission concluded by ordering the allocation of the entire gain on sale to the utility's shareholders.

Q. In that case, did OPC argue before the Commission that the entire gain on the sale received by the utility should be allocated to the utility's customers?

A. Not at all. To the contrary, OPC, through its expert witness, agreed that everything above the full depreciable allowance should be attributed to shareholders, recognizing that it would be unfair to attribute any gain to the customer above the net book value ("NBV"). OPC also agreed that ratepayers do not obtain an ownership interest in utility property through the payment of rates.

Q. Are there other Commission orders addressing the gain on sale of a utility system where the Commission allocated the gain to the utility's shareholders?

A. Yes there are. In the case of In re: Lehigh Utilities, Order No. PSC-93-0301-FOF-WS, issued February 25, 1993 in Docket No. 911188-WS, the Commission, in declining to share the gain on the sale of a water and wastewater facility with the customers, stated:

> [w]e agree with the utility that ratepayers do not acquire a proprietary interest in utility property that is being used for utility service. We also agree that it is the shareholders who bear the risk of loss in their investments, not the Lehigh ratepayers. Further, we find that Lehigh's ratepayers did not contribute to the utility's recovery of its investment in [the facility]. Based on the foregoing, we find no adjustment for the gain on the sale of SAS to be appropriate.
>
> (emphasis added).

Similarly, in the case of In re: Southern States Utilities, Inc., Order No. PSC-93-0423-FOF-WS, issued March 22, 1993 in Docket No. 920199-WS, involving the SAS system at issue in Lehigh Utilities, the Commission held:

> We agree . . . that customers who did not reside in the SAS service area did not contribute to recovery of any return on investment in the SAS system. Further, when this system was acquired by St. John's County, SSU's investment in the SAS system and its future contributions to profits were forever lost. Thus, the gain on sale serves to compensate the utility's shareholders for the loss of future earnings. Arguably, if the sale of this

system had been accompanied by a loss, any suggestion that the loss be absorbed by the remaining SSU customers would be met with great opposition. However, the rationale for sharing a loss is basically the same as the rationale for sharing a gain. Since SSU's remaining customers never subsidized the investment in the SAS system, they are no more entitled to share in the gain from that sale than they would be required to absorb a loss from it.

(emphasis supplied). In both proceedings where the gain on sale arose from the sale of a utility system the Commission ordered the allocation of that gain to the utility's shareholders.

Q: Hasn't the Commission established a clear precedent in the electric utility context that gains and losses on sales should be amortized over 5 years as a credit to the customers' cost of service?

A: Yes, but this policy also extends to water and wastewater utilities, and only in the context of the sale of an *individual* water utility asset. This policy was cited in the cases of In re: Application for rate increase in Charlotte County by Rotunda West Utility Corp., Order No. PSC-96-0663-FOF-WS, issued May 13, 1996 in Docket No. 950336-WS, and In re: Betmar Utilities, Inc., Order No. 24225, issued March 12, 1991 in Docket No. 900688-WS. In both these proceedings, involving water and wastewater utilities, the Commission awarded the gain on sale to the ratepayers because only a particular asset had been sold. The sale of only one specific asset is quite different, however, from the sale of an entire distribution system. Indeed, in the Utilities, Inc. of Florida case discussed above, the Commission agreed with the utility's argument that the electric utility cases in which the gain on sale was awarded to the ratepayers involved gains "associated with specific assets, rather than the sale of facilities, service territory, and the customers," and thus should be distinguished from the sale of an entire system. The gain on the sale of the entire electrical distribution system in Winter Park, including PEF's facilities, service territory, and customers, should not, therefore, be subject to the Commission policy regarding gain on sale of specific assets. The gain from this sale should be awarded to PEF's shareholders, based on the Commission precedent established in the water and wastewater context.

Q: Is there any reason why the principles the Commission has applied in the context of gain on sale of water and wastewater systems should not apply to the gain on sale of an electrical distribution system?

A: No, the principles used by the Commission to award shareholders the gain on sale of complete systems in the context of water and wastewater utilities are analogous to the gain on sale of complete electrical systems. As noted above, the Commission has made the distinction between gain from the sale of specific water and wastewater utility assets (whereby the gain flows to the ratepayers) and gain on the sale of a complete system (whereby the gain is awarded to the shareholders). In the electric utility context, the only issue that has arisen involves gains from the sale of individual assets, not gains from the sale of complete systems. Therefore, the Commission should apply the entirely analogous water and wastewater precedent to PEF's gain on the sale of the entire electrical distribution system in Winter Park, and award the gain to PEF's shareholders. Exhibit No.___ (JP-12) & (JP-13) outlines the impact on revenue requirement from the sale of the Winter Park Distribution System.

<u>**PEF's Adjustment to the Equity Component of Capital Structure**</u>

Q. FRF witness Brown claims the Commission should remove the adjustment to the equity component of capital structure made by PEF pursuant to the settlement agreed to by the parties and approved by the Commission in its investigation of an extended outage at the Company's Crystal River 3 nuclear unit. Would removal of the equity adjustment be appropriate at this time?

A. No, it would not. The CR3 equity adjustment fulfills an important role in assisting PEF's effort toward achieving the balance of debt and equity in its capital structure needed to secure vital capital on favorable terms for the Company's expanding investment requirement in the near and longer term. In addition, the formulation of the Company's financial plans and strategies currently being implemented include the adjustment as a significant component. Ms. Brown's conclusion that the CR3 equity adjustment should be summarily eliminated displays an insensitivity to the disruptive effect such a harsh action would have. I would urge the Commission to take these considerations into account in deciding this important issue.

<u>**Electric Plant In Service**</u>

Q. OPC witness Larkin contends that an adjustment should be made to PEF's test year Electric Plant In Service ("EPIS") based on his review of actual results for the first four months of 2005. Do you agree with his proposed adjustment?

A. No I do not. The analysis of PEF's results through April 2005 prepared by Mr. Larkin as support for his adjustment fails to take into account the Company's

Construction Work In Process ("CWIP"). Had he done so, the reason for the lower than estimated monthly EPIS balance would have been apparent. This is because the estimated and actual combined EPIS and CWIP balances show little variance, which indicates that the EPIS variances are only the result of timing differences in the schedule closing of CWIP to EPIS, particularly in view of the fact that there have been no significant changes in the Company's planned capital projects since the case was filed. As my Exhibit No. __ (JP-20) shows, when the capital expenditures that remain in CWIP balances are included with the monthly EPIS balances, and an adjustment is included for the March 2005 FAS 143 asset write-off described in my direct testimony, the EPIS balance through April 2005 is actually higher than the estimate from the Company's initial filing. The adjustment for the FAS 143 write-off is necessary to make a valid comparison with the projected EPIS balances in Mr. Larkin's exhibit schedule because, although the write-off was made in March 2005, it was not included in the initial MFRs. The account to which the FAS write-off was entered was excluded from rate base and therefore has no effect on the test year.

<u>Construction Work in Progress in Rate Base</u>

Q. FRF witness Brown and OPC witness Larkin contend that PEF has improperly included Construction Work in Progress (CWIP) in test year rate base. How do you respond to this contention?

A. The witnesses are apparently under the impression that CWIP may only be included in rate base using the financial integrity test. This is incorrect. The Commission has long recognized that a utility's investment reflected in CWIP is entitled to a return, either through AFUDC if the CWIP meets the eligibility requirements of Rule 25-6.0141, F.A.C., or through inclusion in rate base for CWIP that is ineligible to earn AFUDC, irrespective of financial integrity considerations. See, for example, Order No. 13771, Docket No. 830470-EI, and Order No. 11437, Docket No. 820097-EI. The CWIP included in PEF's test year rate base is non-AFUDC bearing and therefore qualifies for rate base treatment.

The Commission's policy also helps to ensure a reasonable distribution between AFUDC-bearing and rate base CWIP. A balanced approach is particularly appropriate in this case because many of the projects for which CWIP has been included in rate base involve the replacement of existing assets already used and useful in serving customers. In addition, a reasonable distribution of CWIP in rate base balances future AFUDC returns with a current cash return, which is vital to utilities such as PEF who are in the midst of a significant construction program and therefore must raise substantial amounts of capital.

<u>Plant Held for Future Use</u>

Q. Mr. Larkin asserts that PEF's FERC Form 15 for 2003 and 2004 show the same balance for Plant Held For Future Use ("PHFFU") as the Company has included in its filing for the test year, and that these Form 1s show an scheduled in-service date of May 2005 for the majority of the PHFFU, which he asks the Commission to disallow. Can you explain the discrepancy between the PHFFU in PEF's filing and the information in the two FERC Form 1s?

A. Yes. I note that Mr. Larkin prefaced his proposed disallowance with the statement "if the Company's FERC Form 1 is correct". Therein lies the problem. I have been able to determine that the projected in-service dates shown in the FERC Form had not been updated with the then-current estimate of in-service dates for the property, so I can understand why Mr. Larkin may have made his disallowance proposal. However, I can state with certainty that none of the PHFFU included in the test year has been placed in service. The property remains in PHFFU and continues to meet the criteria for this classification.

In addition, the properties that comprise the PHFFU is of particular strategic value to the Company. The properties are linear, and many of the parcels are adjacent to each other, making them well configured for use as right-of-way in future expansions of the Peninsula's transmission grid. The Commission will no doubt appreciate the increasing difficulty in acquiring right-of-way suitable for this kind of transmission corridor, given the state's rapidly growing population and stringent permitting standards. Because of the state's unique geographic layout, the availability of north-south electrical pathways is even more limited and, hence, more valuable. However, the attractiveness of the property as a potential major transmission corridor also contributes to the difficulty in pinpointing a precise in-service date for the property. The specific need for such a pathway could be triggered by a number of factors that could come into play in the near-term or further into the future, including such considerations as electrical grid capacity constraints, local electrical demand growth, local generation additions, NERC/FRCC criteria, voltage support, or system stability. Despite this element of timing uncertainty, PEF is confident that it is not only prudent, but highly desirable to maintain ownership and control of this property for future use by the Company's and/or the state's transmission grid.

Last Core Nuclear Fuel and End-of-Life Materials & Supplies Reserves

Q. **Are you familiar with the proposed adjustment that Ms. Brown recommends regarding the Last Core Nuclear Fuel and EOL M&S reserves?**

A. Yes. Ms. Brown states that PEF has incorrectly assumed a beginning reserve balance for the Test Year that is significantly less than the actual reserve balances. Ms. Brown acknowledges that the 2006 beginning balances were restated in MFR Schedule B-21, however, based on the annual accrual amounts approved in Order No. PSC-02-0022-PAA-EI. The amount of the Last Core Nuclear Fuel reserve is less than the projected 2005 reserve balance based on continuing the accrual of $1.1 million prior to the implementation of revised base rates. The EOL reserve is less than the projected 2005 reserve balance and even $250,000 less than it was end of year 2004. These amounts imply that no accruals were made for 2005.

Q. **Do you agree with the proposed adjustment that Ms. Brown recommends regarding the Last Core Nuclear Fuel and EOL M&S reserves**

A. Yes. I do concur that rate base and short term debt have been understated and that an adjustment needs to be made to reflect the error in the budget assumptions. However, I do not agree with the amount or the implications surrounding the adjustment. PEF assumed an annual accrual of $1.0 million for the Last Core Nuclear Fuel reserve and $1.5 million for the EOL M&S reserves. The proper accrual that should have been made in the budget was a debit to the O&M expense and a credit to the reserve account. Instead, a debit was booked to the O&M account but the credit was booked to short-term debit. In order for this entry to be corrected, we would need to debit short term debt in the amount of $4,333,340 and credit the reserve account for the same amount. Details are illustrated on Exhibit No.___ (JP-16). This adjustment would result in a reduction to the revenue requirement of $671,841.

<u>**Working Capital Adjustments**</u>

Q. OPC witness Larkin proposes a variety of adjustments to the working capital component of PEF's test year rate base. What is your response to his proposed adjustments?

A. To begin with, there are several of Mr. Larkin's adjustments with which I agree and have shown in my Summary Exhibit No. __ (JP-14). These are:

- Prepayments for Non-Utility Advertising: This prepaid balance should not have been included in test year working capital. The adjustment to remove this item is $2,304,839 system and $2,119,000 retail.
- Employee Receivables and Merchandise Inventory: This entry under Account 143, "Other Accounts Receivable" in the amount of $1,233,648 also should have been excluded from test year working capital. Likewise, the entries to Employee Accounts Payable in the total amount of $261,110 should be excluded as well. The net amount to be removed from working capital is $972,538 system and $796,000 retail.
- Turbine Inventory: I would first like to point out that these turbines are not spares as referred to by Mr. Larkin but rather the actual turbines to be used by Hines Unit 4 upon commercial in-service. Having cleared up this misunderstanding I do agree that an adjustment should be made to exclude these two turbines from test year working capital by moving them from

Hines Unit 4 inventory to an AFUDC-bearing CWIP account. This adjustment reduces working capital in the amount of $46,782,000 system and $38,263,000 retail.

- Allocation of Unbilled Revenue: The Company agrees that the retail allocation of unbilled revenues should be reduced, but believes that the allocation factor based on only the first five months of 2005 proposed by Mr. Larkin is not representative of a full annual period, since unbilled revenues typically fluctuate over the course of a year. The retail portion of PEF's 13-month average unbilled revenues for 2003 was 85%, and the 13-month average for 2004 was 84%, or 84.5% for the two-year period, which the Company proposes as the adjusted retail allocation factor. This results in a reduction to retail working capital of $4,346,000.

Q. What is your reaction to the remaining working capital adjustment proposed by Mr. Larkin?

A. His remaining proposed adjustments to test year working capital are not well founded and should be rejected for the following reasons:

- Over and Under-Recoveries from Adjustment Clauses: The asymmetrical and disparate treatment proposed by Mr. Larkin for including adjustment clause over-recoveries in working capital and excluding under-recoveries is blatantly improper and illogical. Over-recoveries should be excluded from working capital because, like under-recoveries, the cost of carrying these balances is dealt with through the assignment of interest in the adjustment clause proceedings. Conversely, including an over-recovery in working capital would have the effect of charging the Company twice; once through the payment of interest charges in the adjustment clause proceedings, and again in base rates through the loss of a return on the working capital offset by the over-recovery. This double charge result is precisely the point made by Mr. Larkin to explain why under-recoveries should be excluded from working capital. Over-recoveries and under-recoveries are two sides of the same coin.

In this case, however, Mr. Larkin is wrong in his contention that PEF's over-recovery should be included in working capital for a much more simple and practical reason -- he apparently neglected to read the quote from the Commission order included in his testimony. Had he done so, he would have seen in the first line that the Commission had described its policy "to include *net* fuel and conservation over recoveries in working capital." The over-recovery on which Mr. Larkin bases his contention is the Company's conservation clause over-recovery of $8,144,000, which is shown on MFR Schedule B-1, line 4. Lines 5 and 6, however, show that PEF had substantial under-recoveries in its environmental and fuel clauses of $17.0 million and $43.5 million, respectively, for a net under-recovery in excess of $52 million. I feel confident the current Commission would have revisited the statement in the 1993 order cited by Mr. Larkin, which clearly overlooked the unintended consequences it could have caused. The facts in this case, however, demonstrate that the statement simply has no application.

- Removal of Recoverable Job Orders: Mr. Larkin believes an adjustment to PEF's test year working capital is warranted because the Company's adjustment to remove the account for recoverable job orders resulted in an increase to working capital. Since accounts of this type typically add to the level of working capital, one might normally expect to see working capital decrease when such an account is removed. In this case, however, the opposite is true. The recoverable job order has a negative balance. This means that while the negative balance was included, it reduced the level of working capital. Conversely, when it was removed from working capital consistent with standard ratemaking practices, working capital increased.

However, this is not the end of the accounting exercise. The reason the recoverable job order account had a negative balance is that job orders related to the 2004 hurricanes were transferred from the job order account in working capital and reclassified as a regulatory asset. The amount of the hurricane job order exceeded the balance of the account, which left a negative balance after the transfer. The key point in terms of PEF's rate case filing, however, is that the transfer had no net effect on overall test year rate base because the reclassified regulatory asset was also removed from the Company's filling, just as it would have been if the hurricane-related job orders had remained in working capital. In other words, when all of the accounting had been completed and the Company's case was filed, the transfer and reclassification of these job orders, and the negative working capital account balance it created, was transparent to ratepayers.

- Affiliate Receivables: Mr. Larkin is incorrect in his characterization of PEF's accounts receivable from associated companies. These accounts, totaling $11 million, involve utility-related services provided to PEF, the majority of which are from Progress Energy Carolina and Progress Energy Service Company. I would note that affiliate accounts payable in the total amount of $119.1 million are also included in working capital.

- Derivative Accounts: The derivative accounts reflected on PEF's balance sheet represent the Mark-to-Market (MTM) impact of derivative instruments entered into for the benefit of customers in accordance with the Commission's order authorizing PEF and other IOUs to develop hedging programs that would help reduce volatility in fuel prices and where possible, reduce fuel costs. Order No. PSC-02-1484-FOF-EI, Docket No. 011605. The balance sheet impacts of these transactions are completely offsetting and therefore have no impact on rate base.

Q. Are you familiar with the proposed adjustment to working capital that Ms. Brown recommends regarding storm assets?

A. Yes. Ms. Brown states that the working capital component of rate base has been overstated by an improper jurisdictional allocation in the removal of the storm damage reserve that is to be recovered through the Storm Cost Recovery Surcharge ("SCRS").

Q. Do you agree with the proposed adjustment that Ms. Brown recommends regarding PEF's storm assets?

A. Yes. Ms. Brown is correct in stating that the removal of the storm damage reserve should not have had a portion allocated to the wholesale jurisdiction, since the amount of $139 million is only the retail portion of the regulatory storm asset. The full $139 million should have been deducted from the jurisdictional rate base. The adjustment would result in a reduction to the revenue requirement of $2 million.

Working Capital Impact	$ 12,732,000

Revenue Factor	1.632
	$ 20,778,624
WACC - As Filed	0.0950
	$ 1,973,969

Q. Are there any other adjustments to working capital that you would like to address?

A. Yes. During my subsequent review of accrued interest in PEF's initial filing, I have concluded that the forecasted interest accrual was inadvertently charged against short-term debt rather than the accrued interest account in both 2005 and the 2006 test year. As a result, the accrued interest account in working capital was understated and short-term debt was overstated. Therefore, the Company proposes an adjustment to increase accrued interest by $11,387,000 system and $9,313,000 retail. This represents the cumulative effect for both 2005 and 2006 on the 13-month average accrued interest balance included in working capital in PEF's initial filing.

__Deferred Income Taxes__

Q. Mr. Larkin claims that PEF improperly included deferred income tax debits in its capital structure which offset a portion of deferred income tax credits that serve as a source of cost-free capital, thereby reducing the benefit to ratepayers from these deferred credits. Do you agree that including the Company's deferred income tax debits in its capital structure was improper?

A. No I don't. Mr. Larkin's position on this issue sounds like an echo from his position that under-recoveries from the cost recovery clauses are properly excluded from working capital, but that over-recoveries should be included because to do otherwise would increase costs to the ratepayer. I attempted to explain in my earlier response this working capital issue that over and under-recoveries were simply mirror images of each other that required consistent treatment. Deferred income tax debits and credits are no different.

Mr. Larkin is quick to recognize that the deferred debits represent funds advanced by ratepayers before PEF is required to pay the related income taxes and that they should receive a form of return while the Company has the use of these funds. And without question, they should. I am at a loss to understand how Mr. Larkin can recognize the correctness of that result so clearly, and yet contend that when the Company advances funds for the same purpose, providing it a return of those funds would be improper. The fact that PEF's return will partially offset and reduce the ratepayers' return is just one example of an economic truism that occurs throughout the ratemaking process. Mr. Larkin's contention that PEF's deferred income tax debits should be removed from its capital structure is contrary to the basic regulatory principle that funds furnished for a legitimate utility purpose are entitled to a return. His contention that the denial of a return on funds advanced should apply to PEF and not to others similarly situated is contrary to basic principles of fairness. I urge the Commission to reject Mr. Larkin's proposed departure from sound, accepted regulatory principles.

Amortization of Rate Case Expense

Q. OPC witness DeRonne and FRF witness Brown disagree with PEF's deferral of its rate case expense for amortization beginning in 2006 and its use of a two-year amortization period. Why has the Company treated rate case expense in this manner?

A. The Company has used deferral accounting so that the amortization of rate case expense can begin in 2006 in conjunction with the implementation of the rates set in this proceeding. The use of deferral accounting for this purpose is appropriate because the Company's rate case expense is properly attributed to the period when the rates for which the expense is incurred will be in effect. This is consistent with the Commission's normal practice of beginning the amortization of rate case expense in the test year.

A two-year amortization period is appropriate because, in the Company's estimation, that is the most likely period the rates set in this proceeding will be in effect before they are reset in PEF's next base rate proceeding. The establishment of an amortization period based on the expected interval between rate cases is also consistent with Commission practice.

Ms. DeRonne contends that if rate case expense is to be amortized, a period longer than two years should be used based on the extended period between 1992, the Company's last fully litigated rate case, and this proceeding. However, the stark contrast between the period following the 1992 rate case and the period in which PEF operates today belies her suggestion that the prior period is in any way representative of current conditions. For the most part, the remainder of the decade following the implementation of rates from the 1992 rate case was a relatively slow period of generation construction, traditionally the primary trigger for base rate proceedings. In fact, the only base load generating unit placed in service by the Company during this period was the Tiger Bay combined cycle unit, and that came about through a unique buyout of a QF purchase power agreement. However, since 1999, the pendulum has swung well in the other direction and PEF now finds itself in the midst of a rapid generation expansion program. Attendant with this need for significant plant additions is the likelihood of a more frequent need for base rate relief to recognize these highly capital intensive additions.

The beginnings of this pattern can be seen in PEF's 2002 rate case settlement agreement, which provided an innovative means for recognizing the capital investment in Hines Unit 2 through the fuel adjustment clause when the unit was placed in service. This approach provided an alternative to PEF seeking base rate relief when Hines 2 came on line two years later.

With the impending expiration of the settlement's rate freeze, PEF now finds itself before the Commission again to address the recovery of another new generating addition, Hines Unit 3, with a scheduled in-service date almost exactly two years after Hines Unit 2. This is a pattern that will continue over the coming years as new generation is placed in-service essentially every other year, including the scheduled in-service date of Hines Unit 4 in late 2007, two years after Unit 3. Recognizing this pattern, the Company's selection of a two-year amortization period is entirely reasonable and appropriate.

Q. Ms. Brown has suggested that, if a two-year amortization period for rate case expense is used, a mechanism should be established for transforming revenues related to rate case expense into a regulatory asset after two years if no rates from the next rate case have been implemented. What do you think of her suggestion?

A. I disagree. As with the other proposals for "color-coding" revenues that surface from time to time, Ms. Brown's proposal is contrary to, and made unnecessary by, rate of return regulation. Rather than quote from primers on utility regulation, suffice it to say that Ms. Brown's suggestion is not a good one. In this regard, I would note that Ms. Brown herself may not be a true advocate of her suggestion, since she did not propose including a comparable mechanism with the longer amortization period she prefers over a two-year period, which would provide a safeguard in the event her amortization period is too long and new rates are set before the period ends.

<u>**Other Net Operating Income Adjustments**</u>

Q. OPC witness DeRonne proposes an adjustment to reduce PEF's test year expense for uncollectible accounts based on a bad debt factor she calculates from the Company's experience with uncollectible accounts from 2001 through 2004. Do you believe the Commission should accept her proposed adjustment?

A. No I do not. My disagreement with Ms. DeRonne is not with her mathematical skills; I believe she has correctly calculated the average bad debt factor over the four-year period she selected. My disagreement concerns her premise for using a four-year historic average, which is that the conditions during that period which gave rise to uncollectible accounts are representative of the 2006 test year and beyond when the rates will be in effect. In a situation where recent and current experience indicates the charge-offs are expected to increase over the near-term, which is PEF's expectation, a historic average charge-off experience will dampen and distort the more current expectation. I believe Ms. DeRonne's bad debt factor will do just that. I acknowledge that there is a considerable degree of judgment in developing a factor that gauges the current and near-term direction of charge-offs, but I believe more confidence should be placed in the judgment of professionals engaged full time with monitoring and managing uncollectible accounts about where that situation is headed, rather than in a mathematical calculation of where that situation has been in the past.

Q. Ms. DeRonne has also proposed an adjustment to PEF's test year property tax expense for the items listed in her Exhibit No. __ (DD-1). What is your response to those adjustments?

A. I agree with two of Ms. DeRonne's property tax adjustments, the first of which concerns the transfer of two Hines 4 turbines from inventory to CWIP that I addressed previously. The other involves a Company adjustment made in its initial filing to remove the above-market portion of a certain affiliate transaction. However, it is now apparent that we overlooked a follow-up adjustment that should have been made to the property tax calculation. Adjusting test year property taxes for these two items results in a retail reduction of $1,376,000.

I do not agree with Ms. DeRonne's other two adjustments, which concern the property tax aspects of Mr. Larkin's proposed reductions to test year EPIS and Plant Held For Future Use that I addressed earlier in my testimony. I disagree with these two property tax adjustments for the reasons given earlier in my response to Mr. Larkin.

Q. FRF witness Brown contends that PEF has overstated the number of employees in developing its test year payroll and benefits expenses. How do you respond to these contentions?

A. Ms. Brown's contention regarding the number of employees is based on a misinterpretation of PEF's response to an OPC interrogatory stating that no employee <u>positions</u> would be added in 2005 and 2006, from which she mistakenly concluded that the number of positions included in test year payroll and benefits expense should equal the number of actual employees at the end of 2004.

PEF's payroll expense is based on employee *positions*, which includes authorized but temporarily unfilled positions. The reorganization not only resulted in the elimination of a number of positions, but also a number of vacancies in the remaining positions, which the Company is in the process of filling. The test year payroll expense included in PEF's filing has already been adjusted for the reduction in employee positions from the reorganization, as well as for the temporarily vacant, but soon to be filled, positions by the application of a vacancy factor to test year base payroll expense. A further adjustment, therefore, would be unnecessary and inappropriate.

Q. Ms. Brown also contends that PEF's allocation of test year payroll and payroll taxes between expense and capital is inconsistent and allocates too much to expense. Would please address this issue?

A. The rebuttal testimony of Mr. Bazemore addresses this issue in greater detail. The information provided by the Company that she describes in her testimony was the result of inadvertent errors in our responses to certain interrogatories. The interrogatory responses were corrected when the errors were discovered. I have attempted to sort through and clarify the payroll information related to her allocation issue in my Exhibit No. __ (JP-15). Based on the information from our corrected interrogatory responses, which is included in my exhibit, it should be apparent that the allocations of payroll and payroll taxes are consistent with each other and with the Company's recent experience.

Q. Mr. Portuondo as a result of the Commission's recent decision in the 2004 Hurricane Cost Recovery proceeding and discovery question by intervenor's in this proceeding did you include an adjustment for this issue?

A. Yes, my Exhibit No.__ (JP-17) details the adjustment necessary to reflect the decision of the Commission in Docket No. 041272, Order No. PSC-05-0748-FOF-EI. In that order the Commission's decision, as it related to base rate, only impacted the amount of capital to be recognized for base rate. This necessitated that PEF increase total Net Electric Plant In-Service through a charge to Accumulated Depreciation in the amount of $8.4 million, in addition to the amount that had already been estimated by the Company of $1.4 for a minimum amount of removal of $10 million. Additionally, PEF has updated the total projected Electric Plant In-Service for the result through June 31, 2005, defined by the Commission as the cut-off point in their order.

<u>Implementation of PEF's Updated Sales Forecast</u>

Q. You stated at the outset of your testimony that you provide support for the implementation of the updated sales forecast and the jurisdictional separation study provided in the rebuttal testimonies of Company witness John B. Crisp and William Slusser, respectively. How will this be accomplished?

A. My Exhibits No. __ (JP-13, 18 & 19) provide summaries that include the effects of both Mr. Crisp's and Mr. Slusser's rebuttal testimonies. My exhibit also breaks out each of the adjustments to PEF's initial filing that it has proposed or agreed to through the testimony of the Company's rebuttal witnesses or through its discovery responses, the net result of which is a revised revenue deficiency of $209,105,000.

Q. Do you have any additional comments regarding the testimony of the intervenor witnesses filed in this case?

A. Yes, I have one final comment. I wish to make clear that the absence of a specific response in my rebuttal testimony to any other portions of the intervenor witnesses' testimony not addressed above should not be taken to imply my concurrence or acquiescence. I have included responses to the intervenor witnesses where I determined that additional information or clarification was necessary or appropriate beyond that provided in my direct testimony or the direct and rebuttal testimony of other Company witnesses.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing prefiled testimony was assembled under my direct supervision.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 12th day of September, 2005.

Jane Faurot

JANE FAUROT, RPR
Official FPSC Hearings Reporter
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732