BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050078-EI

In the Matter of

PETITION FOR RATE INCREASE BY
PROGRESS ENERGY FLORIDA, INC.
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VOLUME 6

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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 5.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

TESTIMONY

OF

STEPHEN A. STEWART

Q. Please state your name, address and occupation?

A. My name Stephen A. Stewart. My address is 2904 Tyron Circle, Tallahassee, Florida, 32309. I am testifying as a consultant for AARP in this docket.

Q. Please describe your educational background and business experience?

A. I graduated from Clemson University with a Bachelor of Science degree in Electrical Engineering in December 1984. I received a Master's degree in Political Science from Florida State University in August 1990.

From January 1985 until October 1988, I was employed by Martin Marietta Corporation and Harris Corporation as a Test Engineer. In July 1989, I accepted an internship with the Science and Technology Committee in the Florida House of Representatives. Upon expiration of the internship I accepted employment with the Office of the Auditor General in August 1990, as a program auditor. In this position I was responsible for evaluating and analyzing public programs to determine their impact and cost-effectiveness.

In October 1991, I accepted a position with the Office of Public Counsel ("Public Counsel") with the responsibility for analyzing accounting, financial, statistical, economic and engineering data of Florida Public Service Commission ("Commission")-regulated companies and for identifying issues and positions in matters addressed by the Commission. I left the Public Counsel in 1994 and worked as a consultant for the Florida Telephone Association for one year.

Since 1995 I have been employed by two privately held companies, United States Medical Finance Company ("USMED") and Real Estate Data Services Inc. I worked with USMED for approximately four years as Director of Operations. I founded Real Estate Data Services in 1999 and I am currently its President and CEO.

Over the last ten years I have also worked for the Public Counsel on a number of utility related issues.

Q. What is the purpose of your testimony?

A. I am appearing on behalf of AARP in opposition to PEF's request for a rate increase. More specifically, I address four issues, which, taken alone, I believe demonstrate Progress Energy's ("PEF's") requested annual rate increase of $206 million is unreasonable and should be denied. I believe a large portion of PEF's increase should be dismissed because it is related to an excessive requested return on equity ("ROE"). The excessiveness of PEF's ROE request consists of two elements: (1) the base mid-point ROE request of 12.3 percent is excessive as compared to what this Commission has historically granted, and (2) the additional 50 basis points requested as a reward for superior efforts. Eliminating the 50 basis point reward will remove approximately $20 million of PEF's request and setting rates on a mid-point ROE of 10.38 percent (the maximum I believe supported by Commission precedent) will reduce the annual revenue increase by approximately another $76.8 million, for a total annual revenue reduction related to ROE of $96.8 million. I hasten to add that my 10.38 percent recommendation is a maximum ROE (MROE) based on an analysis of the relationship between public utility bond yields and the Commission's ROE awards over the last 25 years. For purposes of an actual current required ROE, AARP supports the 9.1 percent ROE testified to by Public Counsel's cost of equity expert, James Rothschild.

I next address the analysis of PEF witness Javier Portuondo, which is used to support the utility's request for an annual storm accrual of $50 million. I provide an analysis using historic storm costs and various annual accrual levels to evaluate the corresponding levels for PEF's Storm Reserve Fund. My analysis indicates that an increase in the accrual is warranted but that a reasonable and acceptable annual accrual for PEF would be $10 million, not the $50 million requested by PEF.

Lastly, I believe the Commission should treat PEF's very significant depreciation reserve surplus in a manner consistent with the way it has historically handled depreciation reserve deficiencies. That is, the Commission should rebalance, or correct, the depreciation reserve by flowing back the surplus to the benefit of customers over five years – as it often has with deficiencies – as opposed to over the remaining lives of the associated assets. Using just the utility's reported surplus of $504 million and a five-year rebalancing period, would result in reducing PEF's requested annual revenues by approximately $100 million, which, in conjunction with AARP's other suggested adjustments, would reduce the requested revenue increase by over $210 million.

Q. Are the revenue reductions you testify to intended to be the total reductions supported by AARP?

A. No. My testimony is intended to demonstrate to the Commission that analysis of just four areas of PEF's request is sufficient to suggest that the utility should be entitled to no permanent rate increase. It is my understanding that the complete and thorough analysis of PEF's filing by Public Counsel will result in Public Counsel recommending a substantial reduction in PEF's base rates and that AARP will support all of Public Counsel's adjustments.

RETURN ON EQUITY

Q. Do you consider yourself to be an "expert" on either cost of capital or return on equity and are you testifying to a recommended ROE number on behalf of AARP?

A. No, I do not consider myself to be an expert on either cost of capital or return on equity matters and I am not offering an opinion on what the current required ROE is. As I said earlier, AARP adopts the ROE recommendation of Public Counsel witness James Rothschild of 9.1 percent. The number I am offering, 10.38 percent, is what I believe should be the ceiling, or absolute maximum, the Commission should grant PEF as a mid-point for setting rates in this case. This recommendation is based on my analysis indicating that the Commission's ROE awards over the last 25 years in major electric utility cases have had a strong and consistent relationship to the average public utility bond yields at the time of the Commission's ROE decisions. While I believe the Commission should consider ROE testimony in the traditional manner, I also believe my analysis provides a reasonable basis for determining the maximum ratesetting ROE (MROE) the Commission should approve in this case if it is to remain consistent with its precedents of the last 25 years.

Q. Why do you believe your analysis provides a reasonable basis for the ROE award the Commission should ultimately approve in this case?

A. The Commission has never to my knowledge awarded a utility a ROE for ratesetting purposes that was exactly what was testified to by an expert by either the utility or customer intervenors. Rather, typically there is a relatively large spread between the ROE testified to by the experts and usually the Commission makes an award that is somewhere within the range testified to by the experts. For example, in this case Dr. Vander Weide on behalf of PEF has testified to an 12.3 percent ROE, excluding the efficiency reward, and I am told James Rothschild for the Public Counsel will testify to a ROE of 9.1 percent resulting in a spread between these two witnesses of 320 basis points.

Tracking the Commission's ROE awards over the years relative to the experts' recommendations, I was curious as to whether the Commission's decisions bore some discernable relationship to published economic or financial indicators. I believe I found one that does.

Using public utility bond yield data, I have constructed a methodology, which I believe reveals a strong and consistent relationship between average public utility bond yields and the equity awards the Commission has made in major electric cases over the last 25 years.

Q. Describe the methodology used to support your MROE recommendation.

A. There are four stages to the methodology I employed to analyze the MROE for PEF. First, I developed a regression model of the relationship between the average public utility bond yield and the allowed ROE in major rate case decisions across the United States over the period 1980 to 2004. A table of this data, the regression statistics, and the components of the regression model is in Document SAS-1.

Second, I researched and tabulated the Commission's ROE decisions for PEF since 1981. This tabulation is in columns 1, 2, & 3 in the table in Document SAS-2.

Third, I used the regression model from the first stage of my analysis to develop ROE estimates for the years that the Commission awarded an ROE to PEF. These estimates are in column 5 (Model Generated ROE) of the table in Document SAS-2. I compared the model estimates to the Commission's decisions in columns 6 and 7 in the table in Document SAS-2.

Fourth, I used the model to estimate what the MROE would be based on the average public utility bond yields for the most recent 6 months of reported data. This calculation is located at the bottom of Document SAS-2 for PEF.

Q. Please describe your findings?

A. In the first stage, I developed a regression model using data between 1981 and 2004. The model, detailed in Document SAS-1, provides an algorithm which, based on the R-square value (the closer the R-square is to 1.0, the more the variation is explained by the model), demonstrates a strong relationship between the average public utility bond yield and allowed ROE's. These findings indicate the average public utility bond yield is a strong predictor of allowed ROE's over the period of the analysis.

In the third stage I used the regression model to develop an estimate of the ROE for PEF during the various time periods the Commission assigned an actual allowable ROE. These estimates were based on the corresponding average public utility bond yield when each of the awards was made. I compared these estimates with the actual ROE's allowed by the Commission. The findings indicate that the model does a remarkably good job of predicting the Commission-allowed ROE. Column 6 in the table in Document SAS-2 shows the difference between the model generated ROE and the FPSC allowed ROE. I have also included a chart in Document SAS-3 that plots the Commission-allowed ROE's and the regression model estimates. The plot supports the finding that the regression model was very successful in predicting the ROE decisions of the Commission.

In the fourth stage I used the regression model to estimate the MROE, using the available public utility bond yield data for the most recent six months. The MROE was calculated to be 10.38%. In a variation of the chart in Document SAS-4, I created another chart and added the MROE estimate and the PEF requested ROE as data points. Referring to this chart in Document SAS-4, the

MROE estimate follows the downward trend line beginning in 1985. The PEF requested ROE varies significantly from that trend line.

These findings indicate that for the Commission to be consistent with its prior decisions, and absent other well-defined mitigating factors, the *maximum* ROE that should be allowed for ratesetting purposes in this case is 10.38%.

Q. Did you complete any other analysis?

A. Yes. I wanted to verify that the regression model I used was reliable. So I gathered ROE data for all of this Commission's ROE decisions over the last twenty-five years for the four major Florida investor-owned electric utilities and developed a model using the same average public utility bond yield data I employed in the first model. The tabulation of the data, the regression statistics, and the components of the regression model are in Document SAS-5. The results were almost identical, although this model did have a higher R-squared value. This result validates the first model I developed and provides additional support for my recommendation.

Q. Please summarize AARP's position on the appropriate ROE for PEF.

A. AARP adopts the ROE recommendation of the Public Counsel witness Rothschild of 9.1 percent. However, if the Commission should not accept this recommendation, I have provided on behalf of AARP, an analysis based on prior Commission decisions indicating that the *maximum* ROE the Commission should consider allowing in this case is 10.38%. Such an adjustment would necessarily reduce PEF's requested annual revenue increase by $96.8 million (using PEF witness Cicchetti calculation that 50 basis points equates to approximately $20 million in revenue requirements) as compared to the utility's base ROE request of 12.3 percent.

ROE PERFORMANCE INCENTIVE

Q. What is your understanding of the ROE reward requested by PEF in this case?

A. PEF witness Charles J. Cicchetti states at Page 52 that "the Commission should add 50 basis points to reward PEF for its superior performance and encourage it to continue its efforts."

Q. What is AARP's position on the Commission granting PEF an additional $20 million a year through higher customer rates in order to recognize its past superior performance and to encourage its strong operational performance in the future?

A. AARP's position is that the Commission should deny the requested $20 million incentive. First, as Mr. Cicchetti noted in his testimony, PEF has been receiving an incentive for its past performance through the "revenue-sharing" plans included in the settlement agreements approved by the Commission in 2002. It would appear unfair to customers for PEF to be rewarded a second time for its past performance if, indeed, it has already been recognized through the revenue-sharing plans. Secondly, AARP takes the position that PEF has a statutory obligation to provide "efficient" service to its monopoly customers and 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.

Q. What is the statutory obligation you refer to?

A. Section 366.03, Florida Statutes, provides, in part:

> 366.03 General duties of public utility.--Each public utility shall furnish to each person applying therefore reasonably sufficient, adequate, and <u>efficient service</u> upon terms as required by the commission. **(Emphasis supplied.)**

Q. What are you referring to with respect to the basic equity return being adequate especially given the reduced level of risk exposure?

A. What I am referring to is that electric utilities regulated by this Commission now have a very large percentage of their revenues that are subject to 100 percent cost recovery through rates with the result that shareholders are not subject to risk of loss when these various costs experience increases. Examples include fuel cost expenses, conservation cost recovery expenses, environmental compliance costs, many security related costs and an apparently strong likelihood now that electric utilities will be held entirely harmless for storm damage occurring between rate cases when the costs of repairs exceed their storm damage reserves. In short, the "risk" of utility shareholders seeing their profits diminished by increases in a large number of the costs of providing service is substantially less than it was previous to these cost recovery clauses. Arguably PEF's requested ROE should be lower to account for the reduced risks. AARP's position is that the Commission should not give PEF a $20 million a year incentive over and above what it would consider fair and reasonable rates to spur it to operate efficiently.

STORM ACCURAL

Q. Please summarize PEF's request for an increase in the annual storm accrual.

A. Mr. Portuondo states in his testimony that an increase of $44 million above the current $6 million accrual is supported by an updated hurricane risk assessment. PEF's request is for a $50 million annual accrual

Q. Did you complete an analysis on the issue of the proper level of the annual accrual for the Storm Reserve Fund?

A. Yes. I developed a table, shown in Document SAS-6, to determine what the impact on the Storm Reserve Fund would have been if Mr. Portuondo's proposal had been implemented in 1990. In column 2 of the table I have listed the annual storm costs incurred by PEF due to storms. Column 3 in the table shows the actual balance of the Storm Reserve Fund for every year since 1990. Column 4 in the table shows the balance of the Storm Reserve Fund for every year since 1990 assuming a $50 million annual accrual and the recovery of a negative balance over a two-year period. The table shows that the balance after the hurricane season of 2004 would have been $ 515 million.

Q. What other analysis did you complete?

A. Using the same approach, I calculated what the balance in the Storm Reserve Fund would be given various annual accrual amounts. For example, Column 5 shows that an annual accrual of $30 million would have resulted in a Storm Reserve Balance at the end of 2004 of $143 million. For an annual accrual of $10 million, the Storm Reserve Balance at the end of 2004 is calculated to have a deficit of $179 million.

Q. How do you think this Commission should determine the proper annual accrual for PEF in this case?

A. The decision made by this Commission should be based on what is viewed as an acceptable balance in the Storm Reserve Fund. It is my view that the annual accrual should not be set so that the Storm Reserve Fund will cover expenses associated with extraordinary events, such as the hurricane season of 2004. Rather, the accrual should be set to cover normal recurring storm costs.

Q. How does your analysis help the Commission reach their decision?

A. The analysis I have provided will allow the Commission to review the yearly balances based on varying levels of annual accrual. For example the Commission can look at the levels of the Storm Reserve Fund in 2003 to get an idea of what accrual level would be the most appropriate. In 2003, the Storm Reserve Fund balance would have been $790 million assuming an accrual of $50 million, $456 million for an accrual of $30 million and $169 million for an accrual of $10 million. I believe the analysis indicates that the PEF request of $50 million would result in an over funding of the Storm Reserve Fund.

Q. Based on this analysis, what is your recommendation for an annual accrual level?

A. I would recommend an annual accrual of $10 million. Absent extraordinary events, history shows that this annual accrual coupled with the recovery of a negative balance over a two-year period will adequately fund the PEF Storm Reserve.

DEPRECIATION RESERVE SURPLUS

Q. What is your understanding of PEF's depreciation reserve surplus and what position does AARP take on how it should be addressed?

A. First, let me state that AARP supports the Office of Public Counsel's determination that the depreciation reserve surplus is significantly larger than reported in PEF's depreciation study. Specifically, AARP adopts the Office of Public Counsel's position that the depreciation reserve surplus is, in fact, $1.2 billion. However, even if the Commission were to accept the PEF-reported surplus of $504 million, treating that surplus consistently with the Commission's prior treatment of depreciation deficiencies would necessarily result in a substantial reduction of the utility's expenses and a net rate decrease if AARP's other requested adjustments were accepted.

Q. How are you recommending that the Commission address the depreciation reserve surplus?

A. As I said, I am recommending that the Commission treat the depreciation reserve surplus in the same manner it has historically addressed depreciation reserve deficits. From my review of this Commission's prior orders addressing adjustments to depreciation reserve accounts, it appears that the Commission has repeatedly allowed the electric utilities to recover depreciation reserve deficiencies over as few as three to five years and not made the utilities wait to collect the deficiencies over the remaining lives of the related assets. This treatment necessarily caused a greater increase in allowable expenses as compared to the remaining life option. So, if a utility were requesting rate relief in conjunction with a depreciation reserve "correction," rebalancing, or correcting the reserve, over three to five years would increase allowable expenses and with them the revenue requirement and rates. Between rate cases, an adjustment over three to five years would, as opposed to the remaining life option, pull down reported earnings without affecting cash flow. Obviously increasing depreciation expense and reported profits would be more important during periods in which a utility was over earning or close to its profit ceiling. Simple fairness should require the Commission to use the shorter period of years to reduce revenue requirements to the advantage of PEF's customers if it has repeatedly used the shorter term to increase required revenues to the advantage of the utility.

Q. Aside from consistency with its treatment of past depreciation reserve deficiencies, what advantages do you see from correcting the reserve position over a shorter period of years?

A. I think the advantage to consumers is that it gives current customers the benefit of the return of the depreciation expense overpayments they have made and avoids the intergenerational inequity necessarily associated with correcting the reserve over the remaining lives of the related assets. Fundamentally, however, the Commission should be consistent in its treatment of this issue regardless of what direction a correction is required.

Q. Why are you suggesting correcting the depreciation reserve surplus over five years?

A. To be consistent with the number of years often used by this Commission when addressing depreciation reserve deficiencies. It appears that five years is the longest period of years typically used by the Commission when correcting depreciation reserve deficiencies.

Q. Are you recommending a specific revenue adjustment related to the depreciation reserve surplus?

A. No, I am not. I have not attempted to calculate the overall revenue impact, which necessarily would include a related increase in rate base. The adjustment would depend on the surplus found by the Commission based on the record, as well as the number of years used to make the correction. Again, I am recommending a five-year correction because it is consistent with this Commission's precedents in treating reserve deficiencies.

Q. What is the total revenue reduction you are recommending from your four adjustments?

A. A total of approximately $216 million, consisting of $20 million associated with the ROE Performance Incentive, $76.8 million associated with the recommended reduction from 12.3 percent to my MROE of 10.38 percent and $40 million for the reduction in PEF's requested annul storm accrual. The depreciation reserve surplus adjustment will necessarily reduce PEF's allowable expenses by approximately an additional $100 million a year and, thus, turn its remaining positive revenue increase case into a rate reduction case.

Q. Do you believe that these are the only downward adjustments necessary to PEF's request?

A. No. This total is only related to the four items I have discussed in my testimony. AARP plans to adopt the other downward adjustments proposed by the Office of Public Counsel.

Q. Does this conclude your testimony?

A. Yes.

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Before the

Public Utility Commission of Florida

In Re: Petition for Rate Increase by Progress Energy Florida, Inc.	**Docket No. 050078-EI**

Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and president of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have been involved in the regulation of electric utilities, competitive issues and related matters over the last three decades. Additional information is provided in Appendix A, attached to this testimony.

INTRODUCTION AND SUMMARY

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (White Springs). White Springs is a manufacturer of fertilizer products with plants and operations located within Progress Energy Florida, Inc.'s (PEF) service territory at White Springs, and receives service under rate schedules IS-1, IST-1 and SS-2.

Q WHAT IS WHITE SPRINGS' INTEREST IN THIS PROCEEDING?

A White Springs is one of PEF's largest customers consuming more than $20 million of power per year. In contrast to the average increase in base rates of 14% which PEF is seeking, the changes in rate design combined with the overall proposed increase for interruptible customers would cause White Springs' base rates to increase by more than 80%.

Q WHAT IS ADDRESSED IN YOUR TESTIMONY?

A My testimony addresses class cost of service and rate design issues, with particular attention given to the interruptible service schedules. I provide a comparison of PEF's rates with rates of other utilities in the southeastern part of the United States and show that PEF's rates are among the highest. I also show that as compared to its near average position in the early 1990s, PEF's rates are now significantly above the average rates charged by the comparison group of utilities. These high rates are a clear indication that PEF has not "performed" well for its customers and should not be entitled to any kind of "reward."

Q ARE ANY OF YOUR COLLEAGUES ALSO SUBMITTING TESTIMONY ON BEHALF OF WHITE SPRINGS?

A Yes. Mr. Michael Gorman testifies concerning PEF's capital structure, cost of capital and selected other revenue requirement issues. He recommends a return on equity of 9.8%. He also proposes several other adjustments to PEF's claims. Overall, his revenue requirement recommendation is for a decrease of at least $57 million from present rates.

Mr. Alan Chalfant testifies concerning the "performance" reward which PEF has sought for its stockholders. Mr. Chalfant's testimony, which responds to Dr. Cicchetti, explains why this reward is inappropriate.

Additionally, Mr. Thomas J. Regan, President of the PCS Phosphate Division, testifies concerning the impact of PEF's rate proposal on White Springs.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations may be summarized as follows:

1. PEF's rates, for all classes of customers, are among the highest charged by investor-owned utilities in the southeastern part of the United States.

2. Since 1990, the rates for my comparison group of investor-owned electric utilities have increased by approximately 15%, while PEF's rates have increased by more than 50%, making their large industrial rates more than 2.0¢/kWh, or about 45% higher than the group average. Any rate increase would just make the situation worse.

3. PEF has significantly increased its reliance on natural gas-fired resources, which has contributed to the significant escalation in rates. PEF's projections indicate that at least through 2014, it will acquire nothing but gas-fired resources, further increasing its reliance on natural gas.

4. PEF has been slow to seriously consider adding coal-fired resources. In fact, it has already replaced the Southern Company UPS coal-based contracts (expiring in 2010) with resources from Southern that are largely gas-fired.

5. PEF has done little in the way of preliminary work toward developing new coal-fired resources. Although it has indicated that coal-fired capacity could be in place by 2013, its current plans do not show any coal-fired capacity prior to 2015.

6. The class cost of service methodology proposed by PEF is inappropriate. Both of the studies presented include a weighting of energy along with 12 coincident peaks. This has the effect of skewing the allocation of generation capacity costs toward high load factor customers, without giving them a commensurate share of the lower cost of fuel from base load resources.

7. On the PEF system the winter and summer peak demands are the most prominent, and the most important in determining the amount of capacity that must be in place to provide reliable service.

8. My recommendation is to use the summer/winter coincident peak allocation study for cost allocation. If the Commission chooses not to do so, but instead wants to use some measure of energy in the allocation, then I would recommend using the 12 coincident peak study with a $1/13^{th}$ weighting to energy.

9. PEF has proposed significant changes to its interruptible tariffs. Customers on IS-1, IST-1 and SS-2 will receive very large increases because of the change in the application of the credits and the change in the level of the credits themselves.

10. Customers on IS-1, IST-1 and SS-2 would receive increases on their base rates of over 75%, significantly higher than the 21% which PEF advertises on MFR Schedule E-13c. The reason for the difference is that PEF's MFR schedules consider neither the interruptible credit that customers receive currently, nor the drastic change in the level of the credits that would result if its proposals were adopted.

11. PEF has not supported the drastic changes that it proposes for these schedules.

12. My cost of service analysis shows that interruptible rates should be increased less than the system average increase that PEF has proposed (if there is an increase), and be decreased more than the average decrease. Based on the revenue decrease recommended by White Springs, the interruptible schedules should be decreased by at least 14%.

13. The existing credits in IS-1 and IST-1 should not be changed and the method of applying the credits also should not be changed. In addition, the interruptible credits for SS-2 should be designed to maintain the same relationship to the firm standby charges as exists between the demand charge and the interruptible credit in the IS-1 and IST-1 rates.

PEF'S PERFORMANCE

Q ON A GENERAL LEVEL, HOW DOES PEF'S RATE LEVEL COMPARE TO OTHER UTILITIES IN THE SOUTHEASTERN UNITED STATES?

A As I demonstrate below, PEF's rates are among the highest. At the same time that PEF is seeking a bonus for its stockholders, PEF's ratepayers are saddled with unreasonably high rates.

Q HAVE YOU HAD OCCASION TO COMPARE THE LEVEL OF PEF'S RATES WITH THE RATES CHARGED BY OTHER UTILITIES?

A Yes, I have. Exhibit MEB-1 ( ), page 1, shows the comparative cost of power for a large, high load factor firm industrial load under the rates of PEF and 37 other utilities serving generally in the southeastern part of the United States. Significantly, PEF's rates are second highest.

Page 2 of Exhibit MEB-1 ( ) shows a similar comparison with respect to interruptible power. To determine the costs on this exhibit, the maximum amount of allowable interruptible power under each utility's tariff was determined and priced. Since service taken under PEF's interruptible schedules is entirely interruptible, this calculation for PEF reflects 100% interruptible power. For some of the other utilities a portion of the service must be taken as firm, with the balance taken as interruptible. To that extent, this exhibit is conservative (i.e., favorable to PEF) in that it compares fully interruptible power from PEF to a mixture of firm and interruptible power from other utilities.

Q WHAT IS SHOWN ON EXHIBIT MEB-2 ( )?

A This exhibit is a graphical presentation which compares PEF's firm rates with the rates of the comparison group of utilities over the period 1990 through the present. Note that in the early 1990s, PEF's rates were at or near the average, but that now they are approximately 45% above the average.

Q WHAT IS THE SOURCE OF THE DATA SHOWN ON EXHIBITS MEB-1 ( ) AND MEB-2 ( )?

A The costs were calculated from individual utility tariffs and adjustment factors in effect at the times indicated, seasonally weighted to develop the annual cost.

Q THESE TWO EXHIBITS ADDRESS RATES FOR LARGE INDUSTRIAL LOADS. HAVE YOU MADE SIMILAR COMPARISONS FOR OTHER CUSTOMERS?

A Yes. This is included in Exhibit MEB-3 ( ). Data on this exhibit was taken from the Edison Electric Institute's (EEI) semi-annual "Typical Bills and Average Rates Report." The utilities in this exhibit are all of those that are included on Exhibit MEB-1 ( ) for which data is reported in the EEI bulletin. The costs reflected are the weighted average for the summer of 2004 and winter of 2005 in order to reflect annual costs. Page 1 of the exhibit ranks the utilities based on the cost to a residential customer using 750 kWh per month. In this instance, PEF is the fifth highest out of the group of 35. Page 2 is similar, with the ranking based on residential usage of 1,000 kWh per month. Again, PEF ranks fifth highest.

Page 3 is a ranking for a 500 kW, 100,000 kWh per month commercial customer. Here, PEF ranks second highest. Page 4 is a ranking for a 500 kW commercial customer using 180,000 kWh per month. PEF still ranks second highest.

Page 5 is the ranking based on a 1,000 kW industrial customer using 400,000 kWh per month. Again, PEF ranks second. Page 6 is a ranking for a 1,000 kW industrial customer using 650,000 kWh per month. PEF is fourth highest in this ranking.

Q WHAT IMPLICATIONS DO THESE RATE LEVELS HAVE WITH RESPECT TO DETERMINING WHETHER PEF SHOULD BE ENTITLED TO SOME KIND OF A "REWARD" FOR ITS "PERFORMANCE?"

A There are several implications. First, this is not the kind of "performance" that should be rewarded with an ROE bonus. If anything, PEF's ROE should be set at the low end of the range. Second, the Commission should look very closely at PEF's operations to determine why its rates are so high. One obvious reason, which I discuss below, is PEF's significant reliance on natural gas fueled generation. Third, absent prompt and decisive Commission action, PEF's customers will continue to pay excessive rates, thereby harming the Florida economy generally and the competitiveness of Florida's industry, in particular.

PEF'S RESOURCE MIX

Q ARE YOU FAMILIAR WITH THE MIX OF RESOURCES UTILIZED BY PEF TO SERVE THE ENERGY NEEDS OF ITS CUSTOMERS?

A Yes, I am. PEF relies heavily on natural gas to fuel its generation resources.

Q WHAT ARE THE IMPLICATIONS OF THIS HEAVY RELIANCE ON GAS?

A The result is that PEF's customers must pay high fuel costs.

Q HAVE YOU REVIEWED PEF'S RECENT TEN-YEAR SITE PLANS?

A Yes. I have reviewed PEF's Ten-Year Site Plans filed from 2001 through 2005.

Q TO WHAT EXTENT WERE COAL-BASED OPTIONS ADDRESSED IN THESE FILINGS?

A For the more recent plans, there is some discussion of coal-fired alternatives, but the only analysis presented is rather simplistic "screening curves" which examine the theoretical crossover points that show where one technology becomes more economical than another. The resource selections from those plans, which show additions through 2014, were exclusively gas-fired combined cycle units (and combustion turbine units). In none of these plans did coal apparently receive a serious analysis by PEF.

Q CAN YOU PROVIDE AN EXAMPLE OF PEF'S RELIANCE UPON NATURAL GAS-FIRED GENERATION?

A Yes, a good example of PEF's failure to even consider coal-fired generation is provided by its recent execution of unit power sales agreements with Southern Company. Although PEF's existing contract with Southern for 414 MW of coal-fired capacity does not expire until 2010, PEF gave no consideration to whether other coal-fired resources were available, either through purchased power or self-build options (Docket No. 041393-EI, Southern Company UPS Agreements).

Q SHOULD PEF HAVE CONSIDERED ADDING COAL CAPACITY?

A Yes. I believe it was particularly important that PEF undertake these considerations after the gas price spikes that occurred beginning in 2000. That event, coupled with subsequent spikes and escalating price levels, and the continued construction of gas-fired electric generation capacity (by merchants and others) certainly gave rise to concerns that natural gas prices would be both high and volatile. I believe PEF should have devoted more attention to analyzing the comparative risks and economics of natural gas and coal-fired generation.

Q IN ADDITION TO THIS FACTOR, ARE THERE OTHER REASONS WHY PEF SHOULD HAVE BEEN ACTIVELY CONSIDERING ACQUIRING COAL-FIRED POWER?

A Yes. From a resource diversity standpoint, PEF's current projections indicate a significantly increasing dependency on natural gas. For example, its Ten-Year Site Plans show an increase in the percentage of energy from oil and gas-fired resources from 28% in the year 2000, to a projected 34% in 2005, 42% in 2010, and 54% in 2014. This factor should have led PEF to more actively consider adding coal-fired generation to the system to meet part of the load growth requirements and maintain closer to an historic fuel diversity. Exhibit MEB-4 ( ) shows this pattern.

Q HAS THE FLORIDA PSC STAFF COMMENTED ON THIS TREND IN DEPENDENCY ON NATURAL GAS?

A Yes. The Commission's Division of Economic Regulation issued a report in December of 2004 entitled "A Review of Florida Electric Utility 2004 Ten-Year

Site Plans." At Page 6 of that report, in a section entitled "**AREAS OF CONCERN** – *IMPACT OF PLANS ON FUEL DIVERSITY*," the Staff commented as follows:

> "Over the past several years, utilities across the nation and within Florida have selected natural gas-fired generation as the predominant source of new capacity. If this trend continues, natural gas usage will approach the levels of oil usage that Florida was experiencing just prior to the oil embargoes of the 1970's. Recent past experience has shown that natural gas prices can be volatile. Further, Florida's utilities project a wide range of prices for natural gas. These facts, coupled with the Florida utilities' historic under-forecasting of natural gas price and consumption, could further strain Florida's economy. In the 1970's, the Commission took action to encourage the utilities to diversify their fuel mix in an effort to mitigate volatile fuel prices. Based on current fuel mix and fuel price projections, Florida's utilities should explore the feasibility of adding solid fuel generation as part of future capacity additions."

Later in the report, at Page 21, in a section entitled "**GENERATING UNIT SELECTION**" Staff commented as follows:

> "According to the utilities' *Ten-Year Site Plans*, natural gas is forecasted to play an even more dominant role in electric power generation in Florida over the next ten years. To minimize price and supply volatility, electric power generation must rely on multiple fuel sources. As a result, Florida's utilities should evaluate potential sites for coal capability. To lessen the capital cost impact of building coal-fired units, utilities should look at the possibility of joint ownership of future coal units. Florida's municipal utilities have a successful history of sharing investment costs associated with coal units. Finally, utilities should investigate the possibility of receiving financial assistance through the DOE's CCT Program. As emerging research and development in coal-fired generation reduces high capital costs, emissions, permitting lead times, and investment risk, coal could again play a critical role in electric power generation in Florida."

I believe Staff's comments are right on point, and merit serious consideration.

Q IS THERE ANY RECENT EVIDENCE THAT PEF IS NOW LOOKING MORE CLOSELY AT INSTALLING COAL-FIRED UNITS?

A Yes. PEF revealed in the hearings on the Southern Company UPS agreements in Docket No. 041393-EI that its plans now contain mostly coal units beginning in the year 2015. Also, in 2004 we begin to see more serious studies, including some conducted by outside parties, of the comparative economics of various types of solid fuel units. These studies indicate the increasing attractiveness of these types of units in light of changes in fuel markets.

In response to White Springs' Interrogatory No. 15 in the UPS case, PEF claimed that it would take at least eight years to do the necessary development and construction for a coal-fired generating station, and if one accepts that claim, 2013 would be the earliest feasible in-service date.

In light of these circumstances and other factors noted above, PEF should have intensified its efforts in regard to the analysis and development of coal-fired resources, and their expeditious construction if such analysis continues to reveal them as appropriate choices. So far, it appears that PEF has only performed a preliminary site survey. In contrast, a number of coal-fired plants with 2010-2015 projected in-service dates are already in the planning stages by other Florida utilities.

Q SHOULD PEF'S SLOW PACE IN EXPLORING COAL OPTIONS BE TAKEN INTO ACCOUNT IN SETTING PEF'S RETURN ON EQUITY?

A Yes. Even if a single gas-fired resource decision is considered reasonable, PEF has significant capacity needs and could have pursued coal-based options more aggressively than it has. Had it done so, relief from the impact of escalated natural gas prices could become available to PEF's customers at an earlier time. I would urge the Commission to keep this fact in mind as it evaluates PEF's requests.

COST OF SERVICE METHODOLOGY

Q ARE YOU FAMILIAR WITH THE METHODOLOGY WHICH PEF HAS PROPOSED TO USE FOR DETERMINING THE COST OF SERVING ITS VARIOUS CLASSES OF CUSTOMERS?

A Yes, I am. The cost of service studies are sponsored by PEF witness William Slusser.

Q HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A In this section I will first discuss the proposed energy weightings, then I will address the appropriate number of peaks to utilize in the cost allocation process. Finally, I will address the results of the cost of service studies as I have modified them.

Energy Weighting

Q WHAT WEIGHTING OF ENERGY HAS PEF PROPOSED IN ITS CLASS COST ALLOCATIONS?

A PEF has presented two class cost of service studies. The first study uses 12 monthly coincident peaks with a 1/13th weighting of energy as is required to be submitted in the MFRs. An alternative study, which PEF prefers, uses 12 monthly coincident peaks but has a 25% weighting to energy.

Q WHAT ARGUMENT DOES PEF ADVANCE TO SUPPORT ITS PROPOSED ENERGY WEIGHTING?

A It his testimony, PEF witness Slusser indicates (at page 17) that he supports a significant energy weighting in the allocation of production plant capital costs because "...PEF has made a considerable investment in production plant for reasons other than simply meeting peak demand." Essentially, he is arguing that it is necessary to allocate a significant portion of capital costs to classes based on their energy usage because high load factor classes purportedly receive more benefit from the lower energy cost associated with base load units than do lower load factor customers.

To determine his percentage, he estimates what PEF's generation fleet would have required in the way of investment if it were entirely peakers, divides the result by actual investment to obtain a factor of 50%, and then divides that by 2 to derive his recommended 25% weighting which he claims is a "middle ground."

Q DO YOU AGREE WITH MR. SLUSSER'S APPROACH?

A No, I do not. The fact that different technologies have different capital costs and different fuel costs does not provide justification for Mr. Slusser's energy weighting.

Q PLEASE EXPLAIN.

A It is true that utilities select the mix of generation facilities that they expect will be able to serve the total load at the lowest overall cost, taking into account the combination of fixed costs and variable costs, i.e., to minimize total costs.

Having made that decision, the amount of fixed costs on the system is set, and does not vary with kilowatthour output or the number of hours that a facility is operated. These are truly fixed costs, which traditional allocation methods treat as demand-related costs and allocate to customer classes based on a method such as average and excess demands or coincident peak demands, using one or more peaks.

The type of fuel is determined by the specific technology employed, but the total fuel cost varies as a function of total kilowatthour output – and thus is treated as a variable cost. Typically, the variable costs are allocated on the basis of the total annual kilowatthours required by the various customer classes.

Q DOES MR. SLUSSER'S METHODOLOGY APPROPRIATELY REFLECT THE CAPITAL COSTS/FUEL COST TRADEOFFS?

A No, it does not. He only addresses the capital side, and completely ignores the fuel side.

Q PLEASE EXPLAIN.

A Recognizing that the different technologies have different combinations of fixed and variable costs, any analysis that would attempt to more precisely articulate costs by customer class would require a determination of the technology or technologies that would be installed if a utility served each customer class independently, at its lowest cost. The result would be that for high load factor customer classes relatively more base load plant would be installed, and relatively less peaking plant would be installed. The converse would be true for lower load factor classes.

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High load factor classes would have more fixed costs, but they also would have lower fuel costs; while the low load factor classes would be allocated less capital costs but more fuel costs. This type of analysis is necessary in order to reflect both sides of the capital costs/fuel cost tradeoff. The simplistic approach taken by Mr. Slusser simply does not recognize the fuel cost side of the equation, and as a result overcharges high load factor customer classes.

Q IF A SYMMETRICAL APPROACH WERE TO BE FOLLOWED, HOW WOULD IT BE USED TO ALLOCATE THE ACTUAL COSTS THAT A UTILITY HAS INCURRED?

A If this type of analysis were done for each class on a stand-alone basis, then the results of this analysis would have to be analyzed to determine how to apply them to the actual fixed and variable costs which the utility has incurred in pursuit of its goal of selecting that combination of technologies which serves its total load at the lowest total (fixed plus variable) cost.

Q HAVE YOU PERFORMED THIS TYPE OF ANALYSIS?

A No, and neither has Mr. Slusser – but it would be necessary to do so in order to explicitly recognize the impacts of the issues Mr. Slusser has raised.

Q HOW DO TRADITIONAL COST ALLOCATION STUDIES RECOGNIZE THIS MIX OF TECHNOLOGIES?

A Traditional cost allocation studies recognize that the mix or combination of plants is built to serve the overall or combined load characteristics of all customer classes – and not for the load characteristics of any particular customer class.

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Therefore, energy costs are allocated across all customer classes on an equal cents per kilowatthour basis, and fixed costs are allocated across all customer classes on an equal dollars per kilowatt of demand basis. This approach is reasonable, and avoids a lot of complexity and assumptions that would be required if one were to attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs.

Q ARE THERE OTHER REASONS WHY IT IS INAPPROPRIATE TO INCLUDE CAPITAL COSTS IN ALL HOURS OF THE YEAR BY USING AN ENERGY ALLOCATION?

A Yes. In considering the different types of technologies available, the trade-off between variable costs and capital costs that determine which technology is more economical occurs at some specific number of hours of operation. Beyond the hours of operation where there is a "break-even" between the total cost of two different technologies, operating the capital intensive plant more hours does not change the decision of what type of technology to install. Thus, it is only hours up to that point which could even arguably make a difference in technology choices.

Q CAN YOU ILLUSTRATE?

A Yes. Assume Technology A has a capital cost of $500 per kilowatt, a heat rate of 7,000 Btu per kilowatthour, O&M expense of 0.3¢ per kilowatthour, and that it is fired with natural gas at a delivered cost of $7.00 per MMBtu. The total of fuel and O&M expenses would be 5.2¢ per kilowatthour.

Assume that a second technology has a capital cost of $300 per kilowatt, a heat rate of 12,000 Btu per kilowatthour and O&M expenses of 0.3¢ per kilowatthour. With the same fuel price, the total variable cost of this unit would be 8.7¢ per kilowatthour.

The difference in variable cost is, therefore, 3.5¢ per kilowatthour (8.7¢ - 5.2¢). Assuming a carrying charge rate of 15%, the difference in capital cost is $30 per kW (the $200 per kW difference in capital cost times 15%). The break-even point (the hours of operation required for the lower fuel cost to outweigh the higher capital cost) is 860 hours ($30 ÷ $0.035).

This illustrates that only about 10% of the hours in the year (860 out of 8,760) are arguably important in the technology choice question. Since the additional hours are not relevant in this decision – it is wrong to include loads in those additional hours in the cost allocation process – because those loads had nothing to do with the incurrence of the capital cost. The cost allocation methodology used by Mr. Slusser suffers heavily from this problem because he allocates a significant proportion of capital costs on energy.

Q HOW MUCH CAPITAL COST PER KW DID MR. SLUSSER ASSIGN TO EACH CUSTOMER CLASS IN HIS 12CP WITH 25% ENERGY WEIGHTING COST OF SERVICE STUDY?

A This is shown on Exhibit MEB-5 ( ). The values are obtained by dividing the net plant investment allocated to customer classes by the average of the 12 monthly coincident peak demands used in the cost allocation. As expected, classes with an above average load factor are allocated an above average capital cost per kW of demand.

Q DO THE DIFFERENT TECHNOLOGY TYPES HAVE THE SAME FUEL COST?

A No. As noted above, fuel costs vary quite significantly among base load, intermediate and peaking facilities.

Q DOES MR. SLUSSER RECOGNIZE THIS IN HIS ALLOCATION?

A No. As noted above, he allocates the same base rate energy-related cost per kWh to all classes. Furthermore, fuel cost is recovered through the separate fuel adjustment clause, and that also is on an average basis with no distinction made with respect to class load pattern, load factor or how much base load plant and how much production plant investment Mr. Slusser assigns in his cost of service study.

Q ARE THERE SIGNIFICANT VARIATIONS?

A Yes. Exhibit MEB-6 ( ) shows the costs by resource group, as reflected in the workpapers for Mr. Slusser's jurisdictional separation study. The costs range from 2.8¢ per kWh for base load facilities to 9.4¢ per kWh for peaking facilities. If an energy weighting is included in the allocation of capacity costs, then there must be some symmetrical consideration given to the assignment of fuel and variable purchase power costs. The variations in fuel and purchased power costs are quite significant, and it is inconsistent to reflect differential costs on the capital side, as Mr. Slusser has done, and not reflect similar considerations that offset these differences on the energy side.

Q IN PERFORMING THE COST ALLOCATIONS TO THE "STRATIFIED" CUSTOMER GROUP IN THE WHOLESALE JURISDICTION, DOES MR. SLUSSER RECOGNIZE THE RELATIONSHIP BETWEEN THE ENERGY COSTS AND THE CAPITAL COSTS ASSIGNED TO THESE CUSTOMERS?

A Yes, he does. Since he obviously recognizes both sides of the equation in his wholesale allocation, it is not clear why he has not done so in his retail allocation.

Q IN DETERMINING FUEL EXPENSE FOR PURPOSES OF RECOVERY FROM RETAIL CUSTOMERS IN THE FUEL ADJUSTMENT MECHANISM, DOES PEF RECOGNIZE THESE ALLOCATIONS OF FUEL COSTS TO THE "STRATIFIED" WHOLESALE CUSTOMERS?

A Yes. Mr. Slusser indicates on page 9 of his testimony that this is done.

Peaks to Use in Cost Allocation

Q HAVE YOU REVIEWED PEF'S ANNUAL LOAD PATTERN?

A Yes, I have. Exhibit MEB-7 ( ) presents PEF's load characteristics for the historical period 1996 through 2004. Page 1 summarizes key statistics and the balance of the pages in this exhibit show the monthly peak demands in graphical format.

Q WHAT DOES PAGE 1 OF EXHIBIT MEB-7 ( ) SHOW?

A In addition to the system peak, it shows the ratio of the peak demand in the maximum month to the peak demand in the minimum month (column 2) and the ratio of the maximum demand to the average of the monthly peaks (column 3).

Column 2 indicates the extent of spread between the highest monthly (or annual) peak demand and the highest demand in the month which had the lowest maximum demand. The larger this number, the more seasonal the utility system. As can be seen, the PEF load pattern remains very seasonal.

Column 3 is a measure of the extent to which the maximum monthly (or annual) demand exceeds the average of the maximum demands in the other months. Again, the larger the number, the more seasonal the load pattern. Column 3 also indicates a highly seasonal load pattern.

Q THE COLUMN 3 RATIO FOR 2004 SEEMS TO BE MUCH LOWER THAN FOR MOST OTHER YEARS. WHAT IS THE REASON FOR THAT?

A In 2004, as is clearly shown in column 1 on page 1, the system peak was significantly lower than the peak experienced in the preceding several years. Because of a mild weather peak day, the annual peak occurred in the summer, which is not PEF's normal load pattern. The weather pattern in 2004 caused the maximum demand to be lower than expected, and thus the ratio in column 3 is lower than normal.

Q WHAT IS SHOWN ON THE ADDITIONAL PAGES IN EXHIBIT MEB-7 ( )?

A They show, for each year, a bar chart presentation of the monthly peak demands. The annual system peak demand is in orange. A review of this material confirms what is shown on the first page – mainly, that the PEF load pattern continues to be very seasonal.

Q **WHAT IS SHOWN ON EXHIBIT MEB-8 ( )?**

A Exhibit MEB-8 ( ) is similar to Exhibit MEB-7 ( ) except that it shows PEF's projected data for the year 2005 and the 2006 test year. The seasonal pattern here is similar to what the historic data reveals – namely, a strong winter peak.

Q **BASED ON THIS INFORMATION, WHAT METHODOLOGY DO YOU RECOMMEND FOR ALLOCATING FIXED PRODUCTION COSTS TO CUSTOMER CLASSES?**

A This analysis indicates that PEF's load is seasonal, with a strong winter peak, and a somewhat weaker secondary peak occurring during the summer.

In order to provide reliable service, PEF must build capacity or acquire resources under contract to meet its anticipated firm annual system peak demand, plus a 20% reserve margin. Since it is these peaks that drive the capacity additions, it is reasonable to use the average of the winter and summer peak demands for purposes of allocating costs to customer classes.

Cost of Service Results

Q **HAVE YOU PREPARED SUMMARIES OF THE RESULTS OF ALTERNATIVE COST OF SERVICE STUDIES?**

A Yes. Exhibit MEB-9 ( ), page 1, is a summary of the results of the class cost of service study using my recommended summer/winter coincident peak demand allocation methodology. This is similar in format to PEF's summary tables. Lines 1-14 develop the total cost of service. Lines 15-17 show the revenues at current rates, line 18 shows the required revenue change to make class revenues equal to cost of service, and line 19 shows the percentage change.

Q BY UTILIZING A COST OF SERVICE STUDY BASED ON THE FULL AMOUNT OF PEF'S PROPOSED RATE INCREASE, ARE YOU INTENDING TO ENDORSE THAT AMOUNT OF RATE INCREASE?

A Absolutely not. The best way to compare the results of different cost allocation methodologies is to use the same overall revenue requirement. This permits differences due to allocation issues to be isolated from differences due to changes in the level of total revenue requirements.

Q FOCUSING ON THE INTERRUPTIBLE CLASS, HOW DOES THE 7.5% INCREASE YOU HAVE CALCULATED IN THE CONTEXT OF PEF'S INCREASE PROPOSAL COMPARE TO THE RESULTS OF PEF'S COST OF SERVICE STUDIES?

A Under the 12CP and 25% energy weighting study, PEF calculated a required increase for this class of approximately 25%. Under its 12CP and 1/13th average study, it calculated an increase of approximately 22%.

Q WHAT ELSE IS SHOWN ON EXHIBIT MEB-9 ( )?

A The remaining lines on Exhibit MEB-9 ( ) show the unit costs for each class.

Q WHAT IS SHOWN ON PAGE 2 OF EXHIBIT MEB-9 ( )?

A Page 2 of Exhibit MEB-9 ( ) shows the cost of service results if the winter coincident peak demand were used for cost allocation.

Q AS COMPARED TO THE SUMMER/WINTER COST ALLOCATION METHODOLOGY, WHAT ARE THE RESULTS OF THE WINTER COINCIDENT PEAK ALLOCATION METHODOLOGY?

A The winter coincident peak allocation methodology indicates a 4% revenue increase would be required for the interruptible customers, assuming PEF were to get the entire 14% average increase that it has requested. Under this methodology, the increase is approximately one-half of the increase indicated under the summer/winter coincident peak methodology which I have proposed.

Q IN THE COST OF SERVICE STUDIES IN YOUR EXHIBIT MEB-9 ( ) AND IN PEF'S COST OF SERVICE STUDIES, HOW ARE THE LOADS OF THE INTERRUPTIBLE CLASS TREATED?

A For purposes of this cost of service methodology, interruptible loads are treated the same as firm loads – that is, they are included in the peaks used for cost allocation. As an offset, the credits which interruptible customers receive for being interruptible are not subtracted in determining the revenues used in the study. This approach implicitly assumes that the credits which customers receive are appropriate.

Q IS THERE ANOTHER WAY TO VIEW THE COST OF SERVING INTERRUPTIBLE CUSTOMERS?

A Yes. The other way is to exclude interruptible loads from the capacity cost allocation since the utility does not install capacity to serve interruptible load. When this approach is taken, it is necessary to utilize the revenue of the interruptible class after subtracting the interruptible credits that are received by the customers. This approach is a more direct measurement of the cost to serve interruptible load because it compares costs actually incurred to revenues actually received.

Q HAVE YOU PREPARED SUCH AN ANALYSIS?

A Yes. Exhibit MEB-10 ( ) presents this analysis for the interruptible class.

Q VIEWED IN THIS MANNER, WHAT IS THE RESULT FOR THE INTERRUPTIBLE CLASS?

A As determined in this manner, the increase to the interruptible class is less than the increase indicated by the summer/winter coincident peak allocation study which treated the loads as firm. The increase is about 4.5% on the base revenues as PEF presents them (7.4% on the revenues actually paid by these customers). Accordingly, any revenue change for the class should be about 10 percentage points more negative than the average. For example, if the overall revenue change is a 5% reduction, the interruptible class should see a reduction of 15%. I discuss this in more detail in the next section of my testimony.

INTERRUPTIBLE RATES

Q WHAT CHANGES HAS PEF PROPOSED IN ITS INTERRUPTIBLE RATES?

A PEF has proposed massive changes. First, it proposes to eliminate the IS-1 and IST-1 rate schedules and transfer customers to the IS-2 and IST-2 schedules. The proposed increase in base rates, combined with the change in how the interruptible credit is applied, cause substantial increases to these customers.

PEF also proposes to significantly decrease the interruptible credits in the SS-2 standby rate.

Q ON MFR SCHEDULE E-13C, PAGE 1, PEF INDICATES THAT THE BASE RATE PERCENTAGE INCREASE FOR THE IS CLASS IS APPROXIMATELY 21%. IS THIS AN ACCURATE ASSESSMENT OF THE BASE RATE IMPACT?

A No. It is important to recognize that in the MFR schedules the "base rate" revenue for the IS class is prior to the subtraction of the interruptible credits. It also does not show the large proposed reduction in the level of credits. Thus, what PEF calls "base rates" does not truly reflect base rates because the credits are omitted. The credits decrease considerably under PEF's proposal to eliminate the IS-1 and IST-1 rates and move these customers to IS-2 and IST-2. For White Springs, the change in size and application of the interruptible credit causes a real base rate increase of over 80%, or four times what is indicated in the MFR schedule referenced above.

Q ARE YOU ABLE TO ESTIMATE THE OVERALL IMPACT ON THE IS CLASS?

A Yes. It appears that the credits under present rates are approximately $17 million. Thus, the current revenues net of the credits would be approximately $24 million ($41 million - $17 million). At proposed rates, I estimate that the credits would be only about $8 million, so the net base rates after reflecting PEF's proposed increase in rates and decrease in credits would be approximately $42 million ($50 million - $8 million). Thus, the overall increase proposed by PEF for the IS class is approximately 75%, generally consistent with what I calculated for White Springs.

Q WHAT ROLE DOES INTERRUPTIBLE POWER PLAY IN A UTILITY SYSTEM?

A PEF, and other utilities, have utilized interruptible tariffs for many years as a means of reducing the amount of generation capacity that must be installed, consequently reducing the cost of generation resources. Essentially, interruptible customers are offered the use of power when the capacity is not needed to serve the load of firm customers. In the particular instance of PEF, interruptible customers can be called upon (with or without notice and without limitation as to the frequency and duration of interruption) to stop taking service when the capacity that otherwise would serve interruptible load is needed by firm customers anywhere in the state.

In addition, in the event of an identified potential generation resource deficiency, Phase 1 of PEF's operating plan is to notify interruptible (and curtailable) customers of the anticipated need for interruptions. The second phase of the program is to initiate emergency purchases for these customers (who have requested that such purchases be made) and to charge these customers for such purchases. In the event that system conditions become worse, then these customers are required to cease taking service.

Interruptible loads also are equipped with under-frequency relays which are designed to trip the load off of the system before any firm load is shed in the event of the occurrence of an unanticipated system disturbance that creates a generation resource deficiency.

These features of interruptible service are not reflected in class cost of service studies, but clearly bring significant value to the system and to the firm customers.

Q IS PEF CONTINUING TO EXPERIENCE GROWTH IN ITS FIRM LOAD?

A Yes. Both PEF and Florida as a whole continue to experience significant growth, and PEF alone has identified the need to add over 3800 MW of new resources by 2014 in order to provide reliable service. If the dramatic changes which PEF has proposed are adopted and result in discouraging the continued use of this viable resource, then one of two results will occur. If customers decide that interruptible power is not priced far enough below firm power to justify its use, and loads move to firm service, more capacity would have to be added to maintain reliable service. If the higher prices cause customers to reduce or terminate operations, then there will be harm to the economy of the service area.

Q HAS PEF PROVIDED ANY JUSTIFICATION FOR THE MATERIAL CHANGES IN THE IS RATES?

A No. Mr. Slusser simply announces that it is time to eliminate these tariffs and argues that the credits are not appropriate – but offers no evidence.

Q DID WHITE SPRINGS REQUEST ANY SUPPORTING MATERIAL FROM PEF?

A Yes. White Springs requested (White Springs POD No. 26) PEF to provide its most current calculation of the appropriate interruptible credit. In response, PEF provided an outdated (February 2002) conservation cost-effectiveness test calculation. The material provided consists of some summary sheets and one page which lists some assumptions that potentially were used in the calculations. However, the details of the calculations themselves are not provided.

Q PUTTING ASIDE THE SPECIFIC DETAILS OF THE CALCULATIONS, DO YOU BELIEVE THAT THE APPROACH WHICH PEF HAS USED IN THIS EVALUATION IS APPROPRIATE FOR INTERRUPTIBLE RATES?

A No, I do not.

Q PLEASE EXPLAIN.

A The genesis of the methodology was for the evaluation of energy efficiency programs. These programs provide customers with the same firm service, functionality and comfort, but enable them to utilize less energy. A major component of such programs is a reduction in the use of kilowatthours. Accordingly, it was important to evaluate the energy reducing impact of these programs over a number of years.

Interruptible power, on the other hand, has a totally different quality to it than the alternative of firm service. Interruptible service is inferior in that the utility can, under the agreed conditions, withdraw the power from the interruptible customer entirely. The benefit of continuing to serve the load as interruptible is not in reducing energy use, but in the fact that it permits the utility to avoid contracting for purchased peaking power, or constructing peaking units to provide the reliability function that is provided by interruptible customers.

Because of these differences, I believe that the methodology which PEF has applied is not appropriate.

Q **HAVE YOU INDEPENDENTLY EVALUATED THE LEVEL OF THE INTERRUPTIBLE CREDIT?**

A Yes. Exhibit MEB-11 ( ) shows the revenue requirement associated with a combustion turbine, which is a proxy for avoided capacity cost and can be used as a measure of interruptible credit adequacy.

Q **PLEASE EXPLAIN THIS EXHIBIT.**

A It shows the fixed cost revenue requirement of a newly-installed combustion turbine. The calculation uses capital and operating cost data taken from the Energy Information Administration's Annual Energy Outlook, 2005. The revenue requirement was calculated using EIA's capital cost and operating cost data, along with PEF's claimed cost of equity and capital structure. Since PEF maintains a 20% planning reserve margin, the revenue requirement per kilowatt of capacity is increased by 20% to establish the revenue requirement per kilowatt of load served.

Line 3 shows the monthly credit that would be appropriate based on these calculations. Using the first year revenue requirement for the CT would produce a monthly credit of $9 per kW while a levelized revenue requirement calculation would suggest a monthly credit in the vicinity of $7 per kW. Both of these credits are significantly higher than the current credit that applies to the IS-1 and IST-1 rate schedules.

This also clearly demonstrates that the existing credits are significantly below what can be justified, and establishes that PEF's proposal to significantly reduce credits paid to customers should be rejected.

Q UNDER PEF'S PROPOSAL, WOULD THE METHOD OF APPLYING THE INTERRUPTIBLE CREDIT THAT IS CURRENTLY USED IN IS-1 AND IST-1, BE CHANGED?

A Yes. Under PEF's proposal the demand credit would be reduced in proportion to the customer's load factor, as calculated on the customer's billing demand. Currently, a customer receives a credit based on its maximum demand. For example, a customer with a calculated billing load factor for the month of 75% would experience a reduction of 25% in the level of the credit. PEF doesn't explain the reason for this adjustment, or why it is appropriate.

Q DO YOU AGREE WITH THIS APPROACH?

A No. Reducing the credit based on billing load factor assumes that there is a direct relationship between billing load factor and a customer's demand at the time PEF would interrupt. Since the customer has to pay for the maximum demand experienced for the month, and must reduce the demand to zero whenever PEF decides that it needs the capacity, it is appropriate for the customer to receive a credit based on that same maximum demand. PEF's approach greatly understates the value of interruptible power and further adds to the increases that interruptible customers would experience.

Q ARE THERE OTHER SIGNIFICANT CHANGES PROPOSED TO INTERRUPTIBLE TARIFFS?

A Yes. PEF has proposed dramatically to reduce the credits for interruptible demand on the standby schedule, SS-2.

Q DO YOU AGREE WITH THE PROPOSED CREDITS?

A No.

Q PLEASE EXPLAIN.

A To explain the problem with Mr. Slusser's calculation, it is necessary first to consider how the standby charges for firm service were determined. These calculations are set forth on Schedule D to MFR Schedule E-14 Supplement. As shown on page 2, the monthly reservation charge is equal to the production capacity component plus the transmission component, times 10% as an anticipated forced outage factor for cogenerators. The peak day utilization charge is simply the same production and transmission cost divided by 21 on-peak days in a typical month. The standby customer pays the larger of the standby charge or the application of the daily prices to the actual use of standby service. Although this particular 10% factor would tend to overcharge a customer with a more reliable generating facility, the general approach to determining the charges for firm standby service is reasonable.

Q DID MR. SLUSSER USE THE SAME APPROACH TO DETERMINE THE CHARGES FOR INTERRUPTIBLE STANDBY SERVICE?

A No. He started from a completely different place. To calculate the credit for interruptible standby service, he began with his proposed interruptible capacity credit in the IS-2 rate, and multiplied it by 10%. To obtain the daily credit he began with the same IS capacity credit and divided it by 21.

Q WHAT IS WRONG WITH HIS CALCULATION?

A First, the credit that Mr. Slusser starts with (putting aside the issue on whether or not the IS-1 rate should remain in place) is a credit that is applied to the demand charge in the interruptible tariff, it is not a credit that is applied to the unit cost of generation and transmission. Thus, there is a mismatch to begin with. Second, the 10% unavailability factor applies to generation capacity. It is not clear what relationship, if any, it might have to the standby credit. Third, and for much the same reason, simply dividing the credit by 21 days per month has no relationship to the unit cost of generation and transmission to which the credit is applied.

Q HOW SHOULD THESE CREDITS BE CALCULATED?

A I believe the logical way to calculate these credits is to determine the relationship between the credit in the interruptible tariff and the demand charge in the interruptible tariff and use that percentage to apply to the firm standby charges to develop the interruptible credit.

Assuming little or no change in the IS-1 rates, the current relationship of approximately 72% ($3.37/kW credit ÷ $4.70/kW demand charge) should be applied to the calculated firm rate standby charges to determine the credit applicable to customers taking interruptible standby service.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

During the past ten years, Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

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BEFORE THE

PUBLIC SERVICE COMMISSION OF FLORIDA

In re: Petition for rate increase by Progress Energy Florida, Inc.	Docket No. 050078-EI

Direct Testimony of Michael Gorman – Volume 1

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Michael Gorman and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A These are set forth in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (White Springs). White Springs is a manufacturer of fertilizer products with plants and operations located within Progress Energy Florida Inc.'s (PEF) service territory at White Springs, and receives service under numerous rate schedules. During calendar year 2004, White Springs purchased approximately $20 million of power from PEF.

Q WHAT IS THE SUBJECT OF YOUR VOLUME 1 TESTIMONY?

A I make recommendations on an appropriate overall rate of return including a return on common equity for PEF.

Q WHAT IS ADDRESSED IN VOLUME 2 OF YOUR TESTIMONY?

A Other revenue requirement issues.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A I recommend that the Commission award PEF a return on common equity of 9.8%. My recommended return on equity for PEF would fairly compensate investors for PEF's investment risk. I base my recommendation on Discounted Cash Flow (DCF), Risk Premium (RP) and Capital Asset Pricing Model (CAPM) analyses applied to a group of publicly traded utility companies that proxy PEF's investment risk.

My recommended return on common equity will provide PEF an opportunity to earn a fair risk-adjusted return, maintain its bond rating and its financial integrity.

I recommend an overall cost of capital for PEF of 7.39%. This overall rate of return is based on the following: (1) PEF's projected 2006 capital structure, excluding two common equity imputation adjustments PEF proposes and lists on its MRF Schedule D-1b, (2) PEF's estimated embedded security costs, and (3) my recommended return on common equity.

Next, I respond to PEF witnesses Dr. James Vander Weide's and Dr. Charles J. Cicchetti's testimonies. Setting aside some issues I have with his costing models, I find that Dr. Vander Weide's models – when his unreasonable proposed adjustments are excluded – would support my recommended return on equity of 9.8%. As discussed below, and in my colleague Alan Chalfant's testimony, Dr. Cicchetti's recommended 0.50% common equity return premium as a superior management performance reward is unwarranted and should be rejected.

SUMMARY

Q PLEASE DESCRIBE PEF'S CAPITAL RESOURCES AND CREDIT QUALITY.

A PEF is a wholly owned subsidiary of Progress Energy Corp. (Progress), whose primary operating affiliates are Progress Energy Florida and Progress Energy Carolina. Progress' current financial standing is somewhat stressed due to its failure to meet acquisition debt reduction objectives following the merger of Progress Energy Florida and Progress Energy Carolina, and slower than expected divestiture of non-core assets where the proceeds are expected to be used to reduce parent company debt. The primary source of cash for Progress is dividends from its utility affiliates.

PEF's common stock is not publicly traded. Hence, Progress' equity infusions and PEF's retained earnings are its sources of common equity capital. Although PEF directly issues debt, its credit rating is impacted by its affiliation with Progress and its unregulated affiliate companies. PEF's current bond rating from Standard & Poor's is BBB, from Moody's is A2, and from Fitch A-.

Credit rating agencies generally view PEF's regulatory environment as favorable and consider its strong Florida service area economy as supportive of its credit. Further, PEF's current capitalization mix and coverages are also supportive of its current bond rating.

Q **ARE THERE ANY RISK REDUCTION ASPECTS OF FLORIDA PUBLIC UTILITY REGULATION THAT SHOULD BE TAKEN INTO CONSIDERATION IN ASSESSING PEF'S INVESTMENT RISK?**

A Yes. PEF has several rate billing adjustment mechanisms that effectively transfer the risk of cost under-recovery from investors to customers. These billing adjustment rate mechanisms are described in PEF's Rate Schedule BA-1. PEF's billing rate adjustments include rate adjustments for fuel and purchased power energy costs, energy conservation, purchased power capacity costs, environmental costs and gross receipts tax. Each of these mechanisms permit adjustments to reflect changes in the charges to ensure full cost recovery and mitigate regulatory lag. Indeed, as set forth on my Exhibit MPG-1, approximately 55% of PEF's annual retail revenues are recovered through these billing rate adjustment factors.

Q **HOW DO PEF'S RATE ADJUSTMENT FACTORS REDUCE OPERATING RISK?**

A Rate adjustment factors reduce PEF's operating risk in several respects. First, they lower PEF's risks relating to recovering the costs of fuel and energy procurement and compliance with environmental regulations. PEF's risk is reduced because these costs are passed through to customers in rate adjustment factors outside of rate cases. Second, PEF's ability to earn its authorized return is strengthened considerably through the implementation of these rate adjustment factors. As operating expenses increase, PEF's rate factors are adjusted and the changes in operating expense are passed on to customers, shielding PEF's earnings from any negative impact.

Q **DO PEF'S RATE ADJUSTMENT FACTORS IMPACT PEF'S CUSTOMERS?**

A Yes. While these rate adjustment factors significantly reduce PEF's risk, they do not cause the risk to be eliminated but instead shift the risks from PEF to its customers. Customers assume the risk of variations in fuel costs, purchased power costs, environmental and other costs as a result of the exposure to rate adjustment factors.

For example, the Company's fuel recovery factor represents over 50% of the Company's total sales revenues as shown on the Company's MFR Schedule C2 at 1. This fuel cost recovery for projected year 2006 represents a significant increase relative to previous fuel surcharges imposed over the last ten years. Specifically, fuel charges for 2005 are approximately 3.8¢ per kilowatthour, which was more than 1¢/kWh higher than the fuel charges for calendar years 2001 through 2003. Hence, the fuel factor actually increased fuel prices by almost 40%, and total cost by approximately 20%. If the Company had to assume this cost risk it would place it at significant risk of not earning its authorized return. By passing this fuel and purchased power energy cost recovery on to customers, PEF's risk is materially reduced, and customers' price volatility and risks significantly increased.

Q SHOULD THESE RISK REDUCTION FEATURES BE CONSIDERED IN ESTABLISHING PEF'S AUTHORIZED RATE OF RETURN?

A Yes. PEF should not be compensated for risk that is shifted to customers. Rather, the Commission should recognize that PEF's customers have already assumed a significant portion of the risk that PEF might otherwise face and therefore the customers should not have to compensate PEF for risks it does not assume. Accordingly, PEF's authorized return on equity should be reduced to reflect its reduced risk created by these rate factors. The lower return will lower retail rates, thus compensating customers for being subjected to the operating cost risk.

Q HAVE CREDIT RATING ANALYSTS RECOGNIZED THE REDUCTION IN UTILITY RISK THAT RESULTS FROM THE PRESENCE OF RATE ADJUSTMENT MECHANISMS?

A Yes. Standard & Poor's states that it would consider rate mechanisms which enhance a utility's ability to earn its authorized return on equity to be superior to providing a higher authorized return on equity. Standard & Poor's explained:

> "Regardless of the authorized ROE, a utility's cash flow could be compromised and its financial profile could decline from escalating costs such as pension and health care expenses, and much higher than

> historical levels of capital spending. Between rate cases, regulatory mechanisms that provide recovery of costs can support a utility's ability to earn its authorized ROE. As utilities seek recovery of these increasing costs in rates and higher capital spending levels, lower ROEs may be acceptable if other costs are recoverable and the authorized ROE can actually be earned." (Standard & Poor's Rating Direct, June 14, 2005) (Emphasis added)

Florida's rate adjustment factors permit PEF to recover over 55% of its operating costs through rate adjustment mechanisms. This assurance of cost recovery significantly diminishes PEF's operating risk and significantly enhances its ability to earn its authorized return on equity and, thus reduce PEF's operating risk.

This risk reduction should be reflected as a reduction to PEF's authorized return on equity. As Standard & Poor's notes, a reduced equity return to reflect the operating risk reduction aspect would be outweighed by the enhancement to PEF's ability to achieve its authorized equity return and would not diminish PEF's ability to maintain its current bond rating.

PEF'S PROPOSED CAPITAL STRUCTURE

Q WHAT CAPITAL STRUCTURE IS PEF PROPOSING TO USE TO DEVELOP ITS OVERALL RATE OF RETURN IN THIS PROCEEDING?

A PEF witness Thomas R. Sullivan is proposing a projected test year 2006 capital structure and "specific adjustments" as detailed on Minimum Rate Filing (MRF) Schedule D-1d. PEF makes significant adjustments to increase its common equity and decrease its long-term debt balance. PEF's asserted purposes for these adjustments are to neutralize the impact on common equity of a CR3 nuclear outage, and to offset off-balance sheet debt equivalents related to purchased power obligations. In effect, PEF imputes over $850 million of common equity and reduces its debt balance by $110 million for these adjustments.

Q IS IT REASONABLE TO USE MR. SULLIVAN'S PROPOSED CAPITAL STRUCTURE TO SET PEF'S RATE OF RETURN?

A No. There is no sound theoretical or practical reason for this adjustment, and the Commission should summarily reject it. The unavoidable fact is that the adjustment would require PEF's customers to provide a return on common equity investments that shareholders have not made.

Mr. Sullivan's proposed capital structure would inflate PEF's revenue requirement by providing a return on over $850 million of "imputed" common equity. Yet, the shareholders have not provided this $850 million in equity and there is no valid theoretical reason to impute this (or any other) amount. Hence, this imputed balance of common equity is not a legitimate cost of providing service to Florida retail customers.

Q WHAT IS MR. SULLIVAN'S PRIMARY REASON FOR REQUESTING TO IMPUTE DEBT IN SETTING THE COMPANY'S RATE OF RETURN IN THIS PROCEEDING?

A Mr. Sullivan contends that this adjustment is needed to produce a revenue requirement that will support PEF's credit rating. Mr. Sullivan argues that the imputed common equity is necessary to offset PEF's claimed off-balance sheet debt equivalence of purchased power agreement. However, for the reasons discussed below, imputing common equity is not necessary in order to maintain PEF's current bond rating in light of its purchased power debt obligations.

Q **DO THE COMPANY'S PROPOSED ADJUSTMENTS TO ITS CAPITAL STRUCTURE THAT YOU DESCRIBED ABOVE INCREASE ITS REVENUE DEFICIENCY IN THIS PROCEEDING?**

A Yes, significantly. The Company's proposal to impute $850 million of hypothetical common equity to balance purchased power debt equivalents and to eliminate the CR3 nuclear outage common equity impact, increases PEF's revenue deficiency by approximately $45.6 million. Hence, this hypothetical imputed common equity amounts to nearly 25% of PEF's claimed $206 million revenue deficiency in this proceeding.

Q **WHY SHOULD THE COMMISSION REJECT DEVELOPING PEF'S OVERALL RATE OF RETURN USING A CAPITAL STRUCTURE THAT CONTAINS HYPOTHETICAL OR IMPUTED COMMON EQUITY BALANCES?**

A The bottom line is that it would be grossly unfair to require PEF's customers to pay for equity investments that have not actually been made. To do so would artificially inflate PEF's claimed revenue requirement, thereby forcing its customers to pay costs that have not been incurred. Furthermore, the Company's actual bond rating and cost of debt reflects its <u>actual</u> capital structure and financial risk, not the <u>hypothetical</u> capital structure PEF proposes to use to set rates in this proceeding.

Q WHY DOES AN OVERSTATED BALANCE OF COMMON EQUITY INFLATE PEF'S OVERALL RATE OF RETURN?

A Common equity capital is the most expensive form of capital and is subject to income tax expense. For example, assume the Commission authorizes a return on equity of 10%. Customers will pay rates that support the 10% equity return and related income tax expense. Recognizing PEF's 38.6% consolidated Federal and state income tax rate, the revenue requirement, or pre-tax, cost to ratepayers of a 10% return on equity is 16.3% - this includes both the equity return and related income tax expense (10% ÷ (1 – consolidated income tax rate)). In comparison, debt interest expense is tax deductible. Hence, there is no income tax adjustment for the recovery of debt interest expense. The current marginal cost of debt for PEF is around 6%. Accordingly, on a revenue requirement basis, common equity cost would be 16.0%, which is more than two and one-half times as expensive as the revenue requirement cost of debt interest of 6%.

Q CAN A UTILITY HAVE AN INADEQUATE AMOUNT OF COMMON EQUITY?

A Yes. Despite the significant difference in the pre-tax cost of common equity relative to debt, a utility must maintain a capital structure that reasonably balances the amount of common equity and debt capital in order to preserve its financial integrity. A capital structure that is weighted too heavily with debt would have unreasonable amounts of financial risk and would erode the credit quality and limit the utility's ability to attract capital. Conversely, a capital structure that is too heavily weighted with common equity will unnecessarily increase the cost of capital as the utility would be relying too heavily on much more expensive common equity capital. Accordingly, a capital structure that is reasonably balanced with debt and equity minimizes the cost of capital while preserving financial integrity and the ability to attract capital.

Q WHY DO YOU REJECT PEF'S PROPOSAL TO IMPUTE COMMON EQUITY TO OFFSET THE CLAIMED DEBT EQUIVALENT OF PURCHASED POWER OBLIGATIONS?

A I reject its proposal to impute common equity for two main reasons. First, it provides PEF with a return on equity investments that have not been made and is inconsistent with setting rates to recover PEF's actual cost of providing utility service. If additional equity investment is truly needed, and it is not, then Progress should infuse equity in PEF to preserve its credit position.

Second, PEF's actual capital structure and a fair return on common equity will support its credit rating, considering both on-balance sheet and off-balance sheet debt obligations. Indeed, as set forth in more detail later in my testimony, PEF's actual capital structure, excluding the proposed common equity imputation, will provide adequate coverage of debt obligations and will support PEF's current bond rating. Hence, PEF's contention that a significantly greater balance of common equity is needed to support its current credit rating is unfounded.

Q DO CREDIT RATING ANALYSTS CONSIDER OFF-BALANCE SHEET PURCHASED POWER IN EVALUATING A UTILITY'S CREDIT?

A Yes. But credit rating analysts consider the company's actual financial position in setting its credit rating. Credit rating analysts don't look to hypothetical imputations of common equity when assessing a utility's credit strength. Accordingly, the decision in this case should be based on PEF's actual capitalization mix and the coverage of debt obligations that is implicit in the proposed rate of return, capital structure, and depreciation and amortization rates. These are the factors that will allow PEF's retail operations to support its current bond ratings. These are the same actual cash flows and balance sheet factors that credit analysts will consider, in whole or in part, in reviewing PEF's credit strength.

Q ARE THERE IMPORTANT CONSIDERATIONS IN ASSESSING THE DEBT-LIKE NATURE OF PEF'S CURRENT PURCHASED POWER OBLIGATIONS?

A Yes. As noted in the exhibits of PEF witness Sullivan, Standard & Poor's consideration of the "debt like" equivalence of purchased power obligations is based on several factors. First, Standard & Poor's considers performance standards in the contracts in assessing their debt-like nature. Performance standards can mitigate the debt like characteristics of a purchased power agreement. For example, if a company can avoid or eliminate capacity payments in the event a supplier fails to delivery capacity and energy under the contract terms, then the debt like characteristics of that financial obligation are reduced considerably.

Second, Standard & Poor's also considers any regulatory mechanisms that enhance the utility's ability to fully recover purchased power costs. In PEF's case, it recovers its purchased power demand cost and energy costs through rate adjustment factors. Because these mechanisms shift the risk from PEF to its customers, the debt-like equivalence of PEF's purchased power obligations is reduced.

Q **DOES PEF'S ACTUAL CAPITAL STRUCTURE SUPPORT ITS BOND RATING WITHOUT PEF'S PROPOSED HYPOTHETICAL COMMON EQUITY ADJUSTMENTS?**

A Yes. S&P publishes financial ratio benchmarks as a guide to assess the credit strength of utility companies. Based on PEF's projected test year capital structure, excluding its imputed common equity balances, but including PEF's estimated off-balance sheet PPA debt, its total debt to total investor capital will be 52%. This total debt ratio is solidly within S&P's total debt ratio range of 50% to 60% for a BBB-rated utility company with a business profile score of 5, PEF's current rating. Thus, PEF's actual capital structure equity balance is more than adequate to support PEF's credit rating. I review PEF's credit rating financial ratios in more detail later in this testimony.

Q **ARE YOU PROPOSING TO ELIMINATE THE COMPANY'S PROPOSED CR3 NUCLEAR OUTAGE ADJUSTMENTS TO ITS COMMON EQUITY BALANCE AND LONG-TERM DEBT BALANCE?**

A Yes. PEF contends that the Commission authorized an equity imputation adjustment to its capital structure to reflect the disallowances of replacement power costs, and other costs, related to a 1996 Crystal River Unit 3 outage.

While the Commission did permit adjustment to the capital structure for surveillance reporting purposes, it did not authorize an adjustment to PEF's capital structure for the development of based rates.

PEF's proposed adjustments to its capital structure will inflate its common equity, and artificially reduce its debt. PEF's proposal in this regard would create a permanent cost to customers related to the 1996 CR3 outage. Indeed, the Company estimates that this CR3 outage adjustment will increase its revenue deficiency in this proceeding by $12.5 million (Response to White Springs' Second Set of Interrogatories, No. 5B).

The Company's proposal to artificially increase its claimed revenue deficiency in this proceeding by overstating its common equity balance is inappropriate and should be rejected.

Q WHAT CAPITAL STRUCTURE DO YOU RECOMMEND BE USED TO SET PEF'S RATE OF RETURN IN THIS PROCEEDING?

A Based on my elimination of certain common equity and long-term debt adjustments proposed by the Company, as described above, I recommend PEF's rate of return be set based on the capital structure shown on my Exhibit MPG-2. Again, these adjustments include the elimination of the imputed off-balance sheet PPA debt and the elimination of the CR3 nuclear outage adjustment to common equity and long-term debt.

Q ARE YOU TAKING ISSUE WITH THE COMPANY'S DEVELOPMENT OF THE EMBEDDED COST OF LONG-TERM DEBT AND PREFERRED STOCK?

A No.

RETURN ON COMMON EQUITY

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED COMPANY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two decisions of the U.S. Supreme Court, in Bluefield Water Works v West Virginia PSC (1923) and Federal Power Commission v. Hope Natural Gas Company (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards are that the authorized return should: (1) be sufficient to maintain financial integrity, (2) attract capital under reasonable terms, and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q PLEASE DESCRIBE WHAT IS MEANT BY "UTILITY'S COST OF COMMON EQUITY."

A The utility's cost of common equity is the return investors expect, or require, in order to make an investment. Investors expect to achieve their return requirement by receiving dividends and experiencing stock price appreciation.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE THE COST OF COMMON EQUITY FOR PEF.

A I have used several models derived from financial theory to estimate PEF's cost of common equity. These models are: (1) the constant growth discounted cash flow (DCF) model, (2) the bond yield plus equity risk premium model, and (3) a capital asset pricing model (CAPM). I have applied these models to a proxy risk group of publicly traded utilities that I have determined to be reasonably investment risk comparable to PEF.

Q HOW DID YOU SELECT YOUR PROXY RISK GROUP OF PUBLICLY TRADED UTILITIES IN ESTIMATING A FAIR RETURN FOR PEF?

A I first reviewed the proxy risk group of electric and gas utility companies relied on by PEF witness Dr. James Vander Weide. Based on a careful review of the companies included in his comparable groups, I have determined that those two groups are reasonably risk comparable to PEF. Hence, in an effort to minimize the issues between the methods I will use to estimate a fair return for PEF, and those contained in Dr. Vander Weide's analysis, I will use the same two proxy groups used by Dr. Vander Weide. I have reached this decision after reviewing the risk parameters of these groups and determined that they are reasonable risk proxies for use in estimating the cost of equity to PEF.

Q WHY HAVE YOU CONCLUDED THAT THESE PROXY UTILITY GROUPS ARE REASONABLE RISK PROXIES FOR PEF'S INVESTMENT RISK?

A An evaluation of appropriate risk factors, in comparison to PEF, is shown on my Exhibit MPG-3. As shown on this exhibit, the electric utility group's average S&P and Moody's bond ratings of BBB+ and Baa1 are very similar to PEF's current bond rating. Further, the electric group's business position ranking from S&P is 5, which is identical to Progress' current business profile score. Finally, the average common equity ratio to total long-term capital for the comparable electric group is 47%, and 43% when short-term debt is included. These common equity ratios exhibit somewhat greater financial risk, but are reasonably comparable to PEF. Specifically, PEF's common equity ratio of total capital, including short-term debt of 49%, is somewhat stronger, exhibiting lower financial risk than the proxy group's average of 43%.

Similarly, as shown on Exhibit MPG-4, PEF's risk factors exhibit comparable risk to the gas proxy group. Specifically, the gas proxy's S&P bond rating is somewhat stronger, and the Moody's bond rating is comparable. The gas group has somewhat lower business risk and the common equity ratios exhibit comparable financial risk. Hence, the gas comparable group may be slightly lower risk than PEF, but reasonably comparable.

It is difficult to find publicly traded utility company stocks, as most utilities are wholly owned subsidiaries of parent companies that own both regulated and non-regulated operations. Nevertheless, the two proxy groups of electric and gas companies I will use to estimate PEF's current market-required return on common equity exhibit very comparable risk characteristics and represent a reasonable risk proxy for PEF.

DISCOUNTED CASH FLOW (DCF) MODEL

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return (ROR) or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \;.\;.\;.\;.\; \frac{D_\infty}{(1+K)^\infty} \text{ where} \qquad \text{(Equation 1)}$$

P_0= Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the "constant growth" annual DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown under Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q WHAT STOCK PRICE AND DIVIDEND HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices over a 13-week period ending June 13, 2005. An average stock price is less susceptible to market price variations than is a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

A 13-week average stock price is short enough to contain data that reasonably reflects current market expectations, but is not too short a period to be susceptible to market price variations that may not be reflective of the security's long-term value. Therefore, in my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and to capture sufficient data to smooth out aberrant market movements.

I used the most recently paid quarterly dividend, as reported in the Value Line Investment Survey. This dividend was annualized (multiplied by 4) and adjusted for next year's estimated growth to produce the D_1 factor for use in Equation 2 above.

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR DCF MODEL?

A There are several methods one can use in order to estimate the expected growth in dividends. However, for purposes of determining the market required return on common equity, one must attempt to estimate what the consensus of investors believes the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to form individual investment decisions.

Security analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data.[1] Because they are more reliable estimates, and assuming the market, in general, makes rational investment decisions, analysts' growth projections are the most likely growth estimates that are built into stock prices.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. I used the average of three published sources of customer growth rate estimates, including Zack's Detailed Analyst Estimates, Reuters and Thomson Financial. All consensus analyst projections used were available on June 24, 2005, as reported on-line. Each consensus growth rate projection is based on a survey of security analysts. The consensus estimate is a simple arithmetic average of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is most representative of general market expectations. Therefore, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for market consensus expectations. The growth rates I used in my DCF analysis are shown on my Exhibit MPG-5, Pages 1 and 2.

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[1] See, for example, David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A The results of my DCF analyses are shown on my Exhibit MPG-6 and Exhibit MPG-7. My DCF cost of common equity estimates for the electric and gas proxy groups are 9.0% and 9.4%, respectively.

Q DO YOU HAVE ANY COMMENTS CONCERNING THE RESULTS OF YOUR DCF ANALYSIS?

A Yes. I believe my DCF analyses are based on sound investment and economic parameters and reasonably reflect prevailing low cost, low inflation, capital market.

Specifically, the consensus analysts' growth rates for my comparable groups are 4.32% to 5.42%, respectively. These growth rates are reasonable, if not highly conservative, for several reasons. First, these growth rates are reasonably consistent with the consensus of economists' five and ten-year projected GDP growth rate of 5.3%.[2] Growth rates that approximate the long-term projected GDP growth rate represent the maximum sustainable growth rate for electric utility companies. This is true because electric utility companies cannot grow indefinitely at a growth rate that is faster than the economy in which they sell their services. A utility's earnings are tied to its investment in utility plant, and utility plant is typically made to meet growing customer demands. Growing customer demand is, in turn, a function of the growth in the service area economy. Hence, growth in the service area economy represents the maximum

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[2] Blue Chip Financial Forecast, March 10, 2005.

sustainable long-term growth for utility plant investment and earnings. I would note, however, the Energy Information Administration has tracked historical GDP growth in utility earnings and has noted that utility sales growth lags the overall economy, EIA concludes that "... demand for electricity has been related to economic growth, that positive relationship is expected to continue."[3] Accordingly, the nominal GDP growth rate is a conservative high end, i.e., should be considered the maximum, sustainable growth for electric utility companies in the DCF model. Hence, the growth rates used in my DCF analysis are conservatively high.

Second, I conclude the growth rates are conservative in comparison to the GDP growth rate because the growth rate in utility dividends historically has been dramatically lower than the nominal GDP growth rate, see my Exhibit MPG-8. In fact, the dividend growth rate has been closer to that of inflation. Currently, inflation projections over the next five and ten years by a consensus of economists, as published in the Blue Chip Financial Forecast, is 2.5%.

Third, the fundamental factor supporting growth for these companies indicates that they are at payout ratios and dividend to book ratios that would support the sustainable dividend growth as projected by security analysts. For example, the payout ratio for my electric group in 2004 is around 65%, and is projected to be around 60% three to five years out. This percentage payout allows the companies to retain adequate earnings to fund growth going forward. Retaining approximately 40% of their earnings would support moderate growth, again, growth that likely does not exceed the growth of the economy in which

[3] EIA Annual Energy Outlook 2004 at 80.

they sell their services. Similarly, the payout ratio for the gas group is around 60% in 2004, and is projected to be around 52% three to five years out.

Also, the current and projected dividend to book ratios of my electric and gas groups are approximately 6.5% to 7.0%. Hence, an authorized return on equity in the range of 9% to 10% will support the current dividend and allow earnings retention to fund internal future growth.

RISK PREMIUM MODEL

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher ROR to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends on common equity, or to guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. The difference between the required return on common equity and the yield on a bond is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through 2004. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. These authorized returns are typically based on expert witnesses' estimates of the contemporary investor required return.

The 1986-2004 time period was selected because over this period public utility equities have consistently traded at a premium to book value. This is illustrated on my Exhibit MPG-9, where the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Therefore, over this time period, authorized returns were sufficient to support market prices that exceeded book value. This is an indication that authorized returns on common equity supported a utility's ability to issue additional common stock, without diluting existing shares and having a detrimental impact on current shareholders.

The first estimate uses the difference between the required return on utility common equity investments and Treasury bond yields. Based on this analysis, as shown on my Exhibit MPG-10, the average indicated equity risk premium of authorized electric utility common equity returns over U.S. Treasury bond yields was 4.96%. Of the 19 observations, 12 indicated risk premiums fall in the range of 4.4% to 5.7%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums is the best method to measure the current required return on common equity under this methodology.

The second equity risk premium method is based on the difference between regulatory commission authorized returns on common equity and contemporary A-rated utility bond yields. As shown on my Exhibit MPG-11, the average indicated equity risk premium of authorized electric utility common equity returns over contemporary Moody's utility bond yields was 3.54% over the period 1986-2004. The equity risk premium estimates based on this analysis primarily fall in the range of 3.0% to 4.0% over this time period.

Q HOW DID YOU ESTIMATE PEF'S COST OF COMMON EQUITY WITH THIS MODEL?

A I added my estimated equity risk premium over Treasury yields to a projected long-term Treasury bond yield. Blue Chip Financial Forecasts projects the 20-year Treasury bond yield to be 5.5%, and the 10-year Treasury bond yield to be 5.1% (June 1, 2005 at 2). Using the projected 20-year bond yield of 5.5%, and an equity risk premium of 4.4% to 5.7%, produces an estimated common equity return in the range of 9.9% to 11.2%, with a mid-point estimate at 10.6%.

I next added my equity risk premium over utility bond yields to the current 13-week average yield on "A" rated utility bonds for the period ending June 17, 2005 of 5.58%. This current A" utility bond yield is developed on my Exhibit MPG-12. Adding the utility bond equity premium of 3.0% to 4.0% to the "A" rated bond yield of 5.57% produces a cost of equity in the range of 8.6% to 9.6%, with a mid-point of 9.1%.

My risk premium analyses therefore produce a common equity return estimate in the range of 9.1% to 10.6%, with a mid-point of 9.9%.

CAPITAL ASSET PRICING MODEL

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market required ROR for a security is equal to the risk-free ROR, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock;

The stock specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are nondiversifiable risks. Nondiversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as nonsystematic risks. In a broad sense, systematic risks are market risks, and nonsystematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risks that investors will be compensated for are systematic or nondiversifiable risks. The beta is a measure of the systematic or nondiversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A I used Blue Chip Financial Forecasts' projected 20-year Treasury bond yield of 5.5% (Blue Chip Financial Forecast, June 1, 2005 at 2).

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. Therefore, a Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than one, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A I relied on the group average beta estimate for the comparable group. Group average beta is more reliable than a single company beta. A group average beta has stronger statistical parameters that better describe the systematic risk of the group, than does an individual company beta. For this reason, a group average beta will produce a more reliable return estimate.

I relied on The Value Line Investment Survey published beta for each of the companies in my comparable groups. The betas for each of my comparable groups are shown on my Exhibit MPG-13. The electric and gas group betas are 0.80 and 0.81, respectively. For this analysis, I used a beta estimate of 0.80 as a reasonable proxy of betas for electric utilities similar to PEF.

Q HOW DID YOU DERIVE YOUR MARKET PREMIUM ESTIMATE?

A I derived two market premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Ibbotson and Associates' <u>Stocks, Bonds, Bills and Inflation 2005 Year Book</u> publication estimates the historical arithmetic average real market return over the period 1926-2004 as 9.2%. A current five-year consensus analyst inflation projection, as measured by the Consumer Price Index, is 2.5% (Blue Chip Financial Forecasts, March 10, 2005 at 15). Using these estimates, the expected market return is 11.9%. The market premium then is the difference between the 11.9% expected market return, and my 5.5% risk-free rate estimate, or 6.4%.

The historical estimate of the market risk premium was also estimated by Ibbotson and Associates in the <u>Stock, Bonds, Bills and Inflation, 2005 Year Book</u>. Over the period 1926 through 2004, Ibbotson's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.4%, and the total return on long-term Treasury bonds was 5.8%, producing an indicated equity risk premium of 6.6% (12.4% - 5.8% = 6.6%).

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown on my Exhibit MPG-14, my CAPM estimated return on equity falls in the range of 10.6% to 10.7%, with a mid-point of 10.7%.

<u>RETURN ON EQUITY SUMMARY</u>

Q BASED ON THE RESULTS OF YOUR RATE OF RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR PEF?

A Based on my analyses, I estimate an appropriate return on equity for PEF to be 9.8%.

TABLE 1

Return on Common Equity Summary

Description	Percent
Constant Growth DCF	9.2%
Risk Premium	9.9%
CAPM	10.7%

My recommended return on equity of 9.8% is at the mid-point of my estimated return on equity range for PEF of 9.2% to 10.3%. The high end of my estimated range is based on the average of my risk premium and CAPM analyses, and the low end of my estimated range is based on my DCF analyses.

Q WHAT OVERALL RATE OF RETURN DO YOU RECOMMEND BE USED TO SET PEF'S REVENUE REQUIREMENT IN THIS PROCEEDING?

A My proposed capital structure and return on equity, along with PEF's proposed embedded debt and preferred equity costs, are shown on my Exhibit MPG-2. This capital structure and component costs produce a weighted average cost of capital of 7.39%. I recommend this overall rate of return be used to set PEF's revenue requirement in this proceeding.

Q WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT PEF'S CURRENT BOND RATING FROM S&P?

A Yes. I have reached this conclusion by comparing the financial ratios for PEF with my recommended return on equity, capital structure and depreciation expense adjustments I describe later, to S&P's financial benchmark ratios for a "BBB" rated utility with a business profile score of 5 - PEF's current rating.

Q **PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.**

A S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of the Company's <u>total</u> credit risk exposure. S&P publishes a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P rates a utility's business risk based on a business profile score of 1, lowest risk, up to 10, highest risk. Integrated electric utilities typically have a business profile score from S&P of 4, 5 and 6. PEF's current business profile score is 5.

For a business profile score of 5, S&P publishes ranges for three primary financial ratios that is uses as guidance in its credit review for utility companies. The three primary financial ratio benchmarks it relies on in its credit rating process include: (1) funds from operations (FFO) to debt interest expense, (2) FFO to total debt, and (3) total debt to total capital.

Q **HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?**

A I calculated each of S&P's financial ratios based on PEF's cost of service for Florida retail operations. While Standard & Poor's would normally look at total

PEF, and Progress' consolidated financial ratios in its credit review process, my investigation in this proceeding is to judge the reasonableness of my proposed cost of service for rate setting in PEF's retail operations. Hence, I am attempting to determine whether the rate of return and cash flow generation opportunity reflected in my proposed retail rates for PEF will support its current bond rating and financial integrity.

Q **PLEASE DESCRIBE THE RESULTS OF THIS ANALYSIS.**

A The S&P financial metric calculations for PEF's Florida retail operations are developed on my Exhibit MPG-15. This exhibit contains 5 pages. On the first page I show PEF's S&P financial matrix. As shown on this schedule, based on my recommendations in this proceeding, PEF will be provided an opportunity to produce a Funds From Operations (FFO) to debt interest expense of 4.0x. This FFO to interest coverage ratio is at the <u>high end</u> of S&P's benchmark ratio range for a BBB-rated utility company (with a business profile score of 5) of 2.8x to 3.8x. This indicates a very strong BBB rating to a weak "A" rating.

PEF's total debt ratio, including off-balance sheet debt obligations to total capital is 52% This is toward the <u>low end</u> of S&P's BBB-rated utility range of 50% to 60%, indicating a strong BBB rating.

Finally, PEF's retail operations FFO to total debt coverage would be 24%, which is at the <u>high end</u> of S&P's financial metric range for a BBB-rated utility company. Again, this indicates a strong BBB rating.

Q DID YOU REFLECT PEF'S CLAIMED OFF-BALANCE SHEET PPA OBLIGATIONS IN YOUR FINANCIAL RATIO ANALYSIS?

A Yes, I used S&P's method of recognizing the PPA debt equivalence. This consisted of discounting the PPA fixed obligations at a discount rate of 10%, adjusted by my risk factor, and assuming an annual debt interest expense of 10% on the debt equivalent balance. PEF has estimated the off-balance sheet debt equivalent of these PPA obligations using S&P's formula to be $757 million. I relied on PEF's off-balance sheet debt estimate and assumed an annual debt interest expense for PPA obligations of 10%.

Q WHAT DEPRECIATION EXPENSE DID YOU REFLECT IN THIS ANALYSIS?

A I reflected PEF's requested Florida retail depreciation expense, less my proposed $85.2 million adjustment described in Volume 2 of my testimony.

<u>PEF'S RETURN ON COMMON EQUITY PROPOSAL</u>

Q WHAT RETURN ON COMMON EQUITY IS PEF REQUESTING IN THIS PROCEEDING?

A PEF is requesting a return on equity of 12.8%. This return on equity is based on the direct testimony of PEF witnesses Dr. James Vander Weide and Dr. Charles J. Cicchetti. Dr. Vander Weide has applied various financial models to estimate the current return on equity for PEF to be 12.3%. Dr. Cicchetti is recommending a 50 basis point premium to the return on equity, thus raising PEF's requested return to 12.8% from 12.3%. Dr. Cicchetti's proposed return adder is to reward PEF for alleged superior management performance.

Q HOW DID THE COMPANY ARRIVE AT ITS 12.8% RETURN ON EQUITY?

A As shown below in Table 2, the Company's 12.8% return on equity was created in essentially three steps. First, Dr. Vander Weide estimated a current market required return on two utility risk proxy groups of 11.4%. Second, he proposes to increase the proxy groups' return on equity of 11.4% up to 12.3% to reflect his belief that PEF has greater financial risk than does his proxy groups. Finally, Dr. Cicchetti proposes to increase the authorized return on equity by 50 basis points to reflect his belief that PEF has exhibited superior management performance and thereby deserves a return on equity reward.

TABLE 2

PEF's ROE Recommendation

Line	Description	Return	Revenue Requirement Amount (Millions)
1	Comparable Group Return	11.4%	
2	PEF Financial Risk Adjustment	0.9%	$ 40
3	PEF Management Reward	0.5%	$ 22

As shown above in Table 2, Dr. Vander Weide's proposal to increase PEF's authorized return on equity by 90 basis points above the indicated return of the proxy group increases PEF's claimed revenue deficiency by approximately $40 million. Further, Dr. Cicchetti's proposal for a 50 basis point equity risk premium increases the claimed revenue deficiency by approximately $22 million.

Hence, these two adjustments alone amount to over $62 million of the claimed $206 million revenue deficiency, or approximately 30%. These return on equity adjustments represent extraordinary requests by the Company and are out of line with normal regulatory commission practice for determinations of fair returns on equity. These proposals, in my opinion, represent a failure of PEF's management to recognize the need to be a competitive supplier of utility services to its customers. I will further address the impropriety of these proposed adjustments below.

Q **WHY DO YOU RECOMMEND THE REJECTION OF DR. CICCHETTI'S PROPOSED 50 BASIS POINT RETURN ON EQUITY PREMIUM REWARD FOR SUPERIOR MANAGEMENT PERFORMANCE?**

A My colleague, Alan Chalfant, will address the improprieties of Dr. Cicchetti's proposed equity return premium reward in his testimony. I will common on only one aspect of Dr. Cicchetti's claim. Specifically, his basis that PEF should be rewarded because it has not increased "base prices" since 1993 (at 39). This claim, however, ignores important external factors that have played a significant role in reducing PEF's cost of service and eliminated the need for a rate increase. These external factors have nothing to do with management performance.

Q **PLEASE DESCRIBE THESE EXTERNAL FACTORS THAT HAVE HELPED TO REDUCE PEF'S COST OF SERVICE AND DELAYED A BASE RATE FILING.**

A The first and most significant factor relates to the tremendous reduction in capital market costs that has been experienced over the last ten years. The reduction in capital costs is clearly evident from a comparison of PEF's current embedded cost of debt in this proceeding, compared to its embedded cost of debt in previous rate proceedings.

PEF's embedded cost of debt in this proceeding is 5.73%. In its last rate proceeding, which led to a settlement four year ago, PEF's embedded cost of debt was 6.25%. In its 1988 rate case its embedded cost of debt was approximately 9.5%.

For each one-percentage point reduction in PEF's cost of debt, its annual debt interest expense is reduced by approximately $21 million based on the amount of debt it is projecting for its 2006 test year. The four-percentage point reduction in the embedded cost of debt since 1988 represents a reduction in cost of service of approximately $84 million. Similarly, PEF's embedded cost of preferred equity securities has also declined, as has its cost of common equity.

A second factor that has helped PEF avoid base rate increases was its merger with Carolina Power & Light Company (now Progress Energy Carolina). In its filing seeking permission for this merger, Progress identified several synergies that would be created by the combination. The savings through these merger synergies reduced PEF's cost of service and helped avoid base rate increases. These synergistic savings were not the result of superior management performance, but rather were created by the effect of the merger.

Q IS DR. VANDER WEIDE'S PROPOSAL TO INCREASE PEF'S EQUITY RETURN TO 12.3% FROM 11.4%, BASED ON HIS FINANCIAL RISK ADJUSTMENT, REASONABLE?

A No. PEF's total investment risk is composed of both financial and business risk. Business risk is the risk the Company will be able to recover its financial obligations and earn a fair return on equity due to variations in revenue, operating expense control and factors affecting the revenue, including the service area economy, regulatory management uncertainty, and customers' ability to afford the utility's rates. In contrast, financial risk deals with the amount of financial obligations the utility undertakes that must be satisfied before the Company earns a return for common shareholders. A company with significant financial leverage has significant financial risk, and a company with little to no financial leverage has little to no financial risk. Dr. Vander Weide has only examined PEF's financial risk in supporting the return on equity adjustment. Consequently, he has not done a complete analysis of PEF's investment risk.

Dr. Vander Weide's assessment of PEF's financial risk, in comparison to the other utilities, is incomplete. As clearly laid out in PEF's testimony, total financial risk is composed of both on-balance sheet debt obligations and off-balance sheet debt obligations. Dr. Vander Weide completely ignored the differences in off-balance sheet financial obligations of PEF in relation to his proxy groups. Hence, he has failed to do a comprehensive assessment of the differences in financial risk between PEF and his proxy groups. Removing Dr. Vander Weide's financial risk adjustment to the proxy group's market-required return estimate would lower his recommended return from 12.3% down to 11.4%.

Finally, Dr. Vander Weide's assessment of differences in financial risk is flawed for a second reason. Specifically, Dr. Vander Weide's financial risk comparison is based on the market weighted capital structure for his two proxy groups, and PEF's book capital structure. Dr. Vander Weide has failed to recognize two important risk aspects. First, on an equal comparison basis, PEF's book capital structure financial risk is actually lower than the financial risk reflected in his two proxy groups' book capital structure. Second, Dr. Vander Weide has not compared the market-based weight financial risk of PEF to the market-based risk of his two proxy groups. Hence, Mr. Vander Weide's analysis is critically flawed and produces unreasonable results.

Q **IS DR. VANDER WEIDE'S CURRENT MARKET REQUIRED RETURN ON EQUITY OF 11.4% FOR HIS TWO PROXY GROUPS A REASONABLE RETURN ON EQUITY ESTIMATE FOR PEF?**

A No. Dr. Vander Weide supports his return on equity based on a discounted cash flow analysis, an ex-ante and ex-post risk premium analysis, and a capital asset pricing model. These models, as he has used them, develop a common equity return of 11.4%. Dr. Vander Weide applies these models to a proxy group of electric companies and natural gas companies to develop his return estimates. His return on equity results are shown below in Table 3, Column 1. In Column 2, I show my adjustments to Dr. Vander Weide's analyses, which reduce his equity return from 11.4% to 10%. Hence, Dr. Vander Weide's own analyses support my recommended equity return for PEF. My changes include removing unreasonable adjustments he made to the results in his analyses, and reflecting observable market data, rather than his higher projections.

TABLE 3

Dr. Vander Weide's Return on Common Equity Summary

Description	Dr. Vander Weide's Return (1)	As Adjusted (2)
DCF – Electric	9.40%	9.00%
DCF – Gas	9.90%	9.40%
Ex-Ante Risk Premium	11.50%	10.15%
Ex-Post Risk Premium – S&P 500	12.14%	-
Ex-Post Risk Premium – S&P Utilities	11.10%	9.80%
CAPM	11.8% - 12.00%	11.00%
Average	12.30%	9.90%

Q PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VANDER WEIDE'S DCF ANALYSIS.

A The results of Dr. Vander Weide's DCF analysis are overstated for principally two reasons. First, he reflects the quarterly compounding of dividend income in developing his DCF analysis. A quarterly compounding model overstates the DCF return because it provides investors an opportunity to receive dividend reinvestment returns twice – first through the authorized return on equity, and a second time after dividends are declared, paid and reinvested by investors.

Second, Dr. Vander Weide's DCF returns are overstated because he adds a flotation cost adjustment that he has failed to prove is a direct cost to PEF of issuing common equity. Hence, he has increased the return on equity to provide recognition of an expense that has not been shown to be a known and measurable expense for PEF.

Q PLEASE EXPLAIN WHY USING A QUARTERLY DCF MODEL OVERSTATES A FAIR RETURN FOR PEF IN THIS PROCEEDING.

A As noted above, a quarterly DCF model provides investors an opportunity to earn dividend reinvestment returns twice. First through the authorized return on common equity, and a second time when dividends are actually paid to investors and reinvested.

To illustrate this double dip on reinvestment return, I will expand on an example in Dr. Vander Weide's testimony. Dr. Vander Weide supported his quarterly compounding DCF model using the analogy that the quarterly compounding of return is comparable to the yield to maturity on bonds. If this analogy is carefully studied it can clearly be shown that use of a quarterly compounded DCF model overstates the fair return on common equity for ratemaking purposes.

Q PLEASE ELABORATE.

A Consider the interest cost to the utility when it issues a bond. The utility's cost of the bond is based on its semi-annual coupon payments to investors. If a utility issues a bond at face value ($1,000) at a 6% coupon, it will pay $30 coupons every six months to investors for an annual cost to the utility of $60, or 6%. However, when the marketplace values that bond, it will price the bond at a yield to maturity of 6.1% to reflect the investors' ability to reinvest the semi-annual coupon payments. Hence, from the utility's perspective, the bond costs 6% because the utility's cost is a $30 coupon payment every six months.

However, the annual expected return to the investors from receiving $30 of semi-annual coupon payments is 6.1%. The investors receive the two semi-annual $30 coupon payments, and are able to invest the initial $30 coupon payments received at the end of month six for the remaining six months of the year and earn an additional $0.90 return ($30 * (6% ÷ 2)). Hence, at the end of the first year, the investor in the bond will receive $6.00 from the utility, and $0.90 from reinvesting the first semi-annual coupon payment. Thus, while the cost of the bond to the utility is 6%, the yield to maturity on the bond, or expected return to investors, is 6.1%.

This analogy holds for the required common equity return. The cost to the utility relates to the cost of making the quarterly dividend payments and achieving the expected growth. The utility does not compensate the investors for the additional return they will receive by reinvesting the quarterly dividend payments. Hence, the quarterly DCF model overstates the utility's cost of common equity.

Q IS DR. VANDER WEIDE'S ADJUSTMENT FOR A COMMON STOCK FLOTATION EXPENSE REASONABLE?

A No. Dr. Vander Weide estimates a flotation expense adjustment based on a review of other companies' typical flotation cost. He has not shown that the results of his analysis are representative of flotation expenses that PEF has incurred and should recover from customers. Indeed, Dr. Vander Weide has not demonstrated whether there are any flotation costs incurred by PEF that have not been fully recovered from customers in previous rate proceedings, or rate settlements, concerning acquisitions and other activities. Hence, his proposed flotation cost adjustment reflects compensation for expenses that have not been shown to be reflective of PEF's cost of service. Indeed, these expenses are simply not known and measurable expenses. Therefore, in order to preserve the integrity of the ratemaking process, this adjustment should be rejected.

Q HOW WOULD DR. VANDER WEIDE'S DCF ESTIMATES CHANGE BASED ON HIS DATA, EXCLUDING THE QUARTERLY COMPOUNDING AND THE ERRONEOUS FLOTATION COST ADJUSTMENT?

A As shown on the attached Exhibit MPG-16, Dr. Vander Weide's electric and gas DCF would be reduced to 9.0% and 9.4%, respectively.

Q PLEASE DESCRIBE DR. VANDER WEIDE'S EX-ANTE RISK PREMIUM ANALYSIS.

A Based on a discounted cash flow analysis of a group of electric and gas companies in comparison to the contemporary A-rated utility bond yield, Dr. Vander Weide estimates a risk premium for electric and gas companies of 4.3% and 4.69%, respectively. He then adds these equity risk premiums to his forecasted yield on A-rated utility bonds of 6.94%. As a result, Dr. Vander Weide estimates a return on common equity in the range of 11.3% to 11.6%, with a mid-point of 11.5%.

Q **IS DR. VANDER WEIDE'S EX-ANTE RISK PREMIUM ANALYSIS REASONABLE?**

A No. Dr. Vander Weide's risk premium analysis overstates the cost of equity because he uses a projected A-rated utility bond yield of 6.94% rather than the current yield. The current A-rated utility bond yield is approximately 5.6%. Dr. Vander Weide's projected yield of 6.94% is a 1.34 percentage point increase to the prevailing market rate for single-A utility bonds. Using the more appropriate current yield would reduce Dr. Vander Weide's ex-ante risk premium from 11.5% to 10.15%.

Q **IS IT REASONABLE TO USE A PROJECTED A-RATED UTILITY BOND YIELD AS DR. VANDER WEIDE HAS DONE IN HIS RISK PREMIUM STUDIES?**

A Projected bond yields are highly problematic, especially if the projection is not based on an independent source that may reflect the consensus of investors' expectations. Dr. Vander Weide's projected bond yield is not based on an independent source, but rather is based on his own projections supporting his inflated return on equity in this proceeding. Further, Dr. Vander Weide's projected A-rated utility bond yield has not been shown to be reasonably reflective of any market participant other than possibly himself. Consequently, Dr. Vander Weide's utility bond yield projections are unreliable and a biased estimate.

Further, Treasury bond yields and corporate bond yields are projected to increase relative to current levels. However, I would note there is significant uncertainty with respect to this expectation. Specifically, Treasury bond yields have been projected to increase significantly for several years now. However, those projected increases to prevailing spot yields has not been realized over the last several years. Hence, economic projections for increased long-term yield rates are highly uncertain and are not an appropriate means by themselves to support a utility's authorized return on equity in a current rate base. This is true because if interest rates do ultimately increase over time, utilities are free to seek rate relief and request returns on equity that reflect higher capital costs. However, if interest rates do not increase, as they have failed to do over the last few years, then authorizing a return on equity based on today's current yields, along with some consideration of projected increases to those yields, as I have captured in my return on equity estimates, provides a fair and balanced means of estimating a fair return on equity. Dr. Vander Weide's method does not meet this standard.

Q **PLEASE DESCRIBE DR. VANDER WEIDE'S EX-POST RISK PREMIUM ANALYSIS.**

A Dr. Vander Weide's ex-post risk premium analysis consists of reviewing the historical achieved returns on common equity investments from two proxy indexes, relative to the achieved return on investing in Moody's A-rated utility bonds. Dr. Vander Weide estimates an equity risk premium in the range of 4.16% to 5.27%. The 4.16% equity risk premium is based on the achieved return of the S&P utility stock index relative to the achieved return on Moody's A-rated utility bonds. The 5.27 percentage point equity risk premium is based on the achieved return of the S&P 500 relative to Moody's A-rated utility bonds. He adds these equity risk premiums to his projected A-rated utility bond yield of 6.94%, and then adds 25 basis points for a flotation cost adjustment. With this method he estimates a return on equity for PEF of 11.9%.

Q DOES DR. VANDER WEIDE'S EX-POST RISK PREMIUM ANALYSIS OVERSTATES A FAIR RETURN FOR PEF?

A Yes. Both of Dr. Vander Weide's ex-post risk premium analysis should be rejected.

Q PLEASE EXPLAIN.

A His equity risk premium based on a comparison of the S&P 500 to A-rated utility bond yields should be rejected because it does not measure an appropriate risk-adjusted return for PEF. Dr. Vander Weide has not shown any evidence that the S&P 500 is an appropriate proxy index for PEF's investment risk. Indeed, his CAPM analysis is an implicit admission that PEF has a lower risk than the overall market. Hence, the equity risk premium to the S&P 500 overstates the equity risk premium for PEF.

His second ex-post analysis also is flawed. It compares the S&P utilities index to the yield on utility bonds. The S&P utilities index includes companies that may not be risk comparable to PEF. Dr. Vander Weide has not shown that this index is an appropriate risk proxy for PEF. Nevertheless, applying the equity risk premium derived in this analysis to the current A-rated utility bond yield of 5.6%, rather than Dr. Vander Weide's exaggerated projected A-rated utility bond yield of 6.9%, would produce an ex-post risk premium cost projection of about 9.8%. Hence, this analysis, excluding flotation cost adjustments for the same reasons discussed above, would support my return on equity recommendation for PEF.

Q **PLEASE DESCRIBE DR. VANDER WEIDE'S CAPM ANALYSIS.**

A Dr. Vander Weide relies on a projected Treasury bond yield of 5.7%, a beta estimate for utility companies of 0.81, and estimates of the market risk premium of 7.2% and 8.45%. With these parameters, and a 25 basis point flotation cost adjustment, Dr. Vander Weide estimates a CAPM return in the range of 11.8% to 12.0%.

Q **IS DR. VANDER WEIDE'S CAPM ANALYSIS REASONABLE?**

A No. Dr. Vander Weide's CAPM result is overstated, largely because his estimated risk premium for the marketplace is overstated and not supported. First, his market risk premium estimate is based on Ibbotson & Associates' market return relative to Treasury bond income returns. I reject this method of estimating the market risk premium. Ibbotson & Associates estimates this market risk premium by looking at the historical achieved return on common equity, relative to the contemporary utility bond yields. Specifically, Ibbotson & Associates excludes returns investors receive due to changes in bond prices over time. This method of estimating market to risk premium is unreasonable for two reasons. First, it is not possible to invest in utility bonds without experiencing changes in the bond market value over time. Hence, the market risk premium is overstated because it does not reflect significant gains investors have received by investing in Treasury bonds as a result of reductions in interest rates. These declines in interest rates likely did have a positive impact on the returns earned on common stocks.

Second, the analysis is, on its face, inappropriate. Specifically, the common equity return is based on a historical achieved return on utility stocks. The Treasury bond yields are based on income returns based on the bond yield returns at any given point. Hence, the yield is a forward-looking return estimate. Consequently, the risk premium is based on a historical equity return, and a forward-looking bond return. This is an inconsistent apples to oranges method of estimating risk premium.

Dr. Vander Weide estimates a second CAPM analysis and market risk premium based on a DCF return for the S&P 500 of 13.15%, less his risk free rate estimate of 5.7%. This implies a market risk premium of 7.45%. Dr. Vander Weide's estimated return of 13.15% reflects his quarterly compounding DCF model assumption, which overstates DCF return estimates for the reasons discussed above. Eliminating this double-counting assumption in the DCF cost estimate would reduce his market risk premium and reduce his CAPM estimate. Further, a projected return on the market of 13.15% seems highly problematic, if not overly optimistic, given today's very low cost capital market and historical tendency of the S&P 500 to earn a return of around 12%, much lower than Dr. Vander Weide's projections.

In any event, eliminating the flotation cost adjustment of 0.25% from Dr. Vander Weide's risk premium analysis, and relying on a more reasonable, yet conservative, market risk premium estimate of 6.6% (my high end estimate described above), would support a CAPM return estimate of approximately 11.0%, as described above.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes.

Qualifications of Michael Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a managing principal with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission (ICC). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals (RFPs) for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements. Continuing, I have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Q **HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the regulatory commissions in Arizona, Arkansas, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Michigan, Missouri, New Mexico, New Jersey, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, the St. Louis Metropolitan Sanitation District, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q **PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.**

A I earned the designation of Chartered Financial Analyst (CFA) from the Chartered Financial Analyst Society. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the St. Louis CFA Society.

MPG:cs/8383/69404

BEFORE THE

PUBLIC SERVICE COMMISSION OF FLORIDA

In re: Petition for rate increase by Progress Energy Florida, Inc.	Docket No. 050078-EI

Direct Testimony of Michael Gorman – Volume 2

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (White Springs). White Springs is a manufacturer of fertilizer products with plants and operations located within Progress Energy Florida Inc.'s (PEF) service territory at White Springs, and receives service under numerous rate schedules. During calendar year 2004, White Springs purchased approximately $20 million of power from PEF.

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A This is the second volume of my testimony. In Volume 1 I address proposed capital structure and return on equity adjustments. In this Volume 2 I describe my proposed adjustments for surplus depreciation, T&D net salvage depreciation expense, rejection of PEF's proposed fossil station dismantlement expense and a refund of nuclear decommissioning reserves to customers. I propose several adjustments to PEF's claimed revenue deficiency. As shown below in Table 1, my adjustments to PEF's claimed revenue requirement reduce its revenue deficiency from $206 million, to a reduction of $56.8 million.

TABLE 1

Revenue Requirement Summary (Millions)

	Retail Amount
PEF's Claimed Revenue Deficiency	$205.6
Adjustments:	
Capital Structure	45.6
Reduce ROE to 9.8%	113.9
Depreciation Surplus Amortization	33.6
T&D Expense Net Salvage Adj.	42.0
Reject Fossil Station Dismantlement Expense	9.6
Return Excess Nuclear Decommissioning Reserve	17.7
Total Adjustments	$262.4
Adjusted Revenue Deficiency (Surplus)	$ (56.8)

My proposed capital structure and return on equity adjustments are described in my Volume 1 testimony. Below I describe my proposed adjustments for surplus depreciation, T&D net salvage depreciation expense, rejection of PEF's proposed fossil station dismantlement expense and a refund of excess nuclear decommissioning reserves. In total, I recommend reductions to the Company's proposed retail depreciation expense in the amount of $85.2 million. This depreciation expense reduction was reflected in the retail financial ratio calculations in my Volume 1 testimony.

Q ARE THESE THE ONLY ADJUSTMENTS THAT SHOULD BE MADE TO PEF'S REQUEST?

A No. Adjustments proposed by other parties must also be considered.

PEF's Depreciation Reserve Surplus

Q PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS FOR PEF'S DEPRECIATION RESERVE SURPLUS.

A I recommend a reduction to PEF's proposed annual depreciation expense of $38 million to achieve an accelerated payback of surplus depreciation reserves. Specifically, I propose to flow back approximately $250 million of the surplus depreciation reserves over a five-year period. This would be an acceleration to the Company's implicit proposal to flow back this accelerated depreciation reserve over the remaining life of PEF's assets, or approximately 21.3 years. My proposed $38 million adjustment is based on a $50 million amortization of surplus reserves ($44 million retail), offset by an adjustment to the Company's proposed new depreciation rates. The retail portion of the $38 million total electric depreciation expense adjustment will reduce jurisdictional retail electric depreciation expense by approximately $33.4 million.

Q DOES PEF HAVE A DEPRECIATION RESERVE SURPLUS?

A Yes. PEF indicates that the actual book accumulated depreciation reserve has a surplus of approximately $754 million, or 21% in excess of the reserve level estimated to be appropriate by PEF. Even factoring in the allocation of the retail reserve debit of $250 million created by PEF's last rate settlement, the remaining accumulated depreciation reserve surplus is approximately $504 million.

Q WHAT CAUSES THE DEPRECIATION RESERVE SURPLUS?

A The depreciation reserve surplus is the difference between the actual book depreciation reserve and the theoretical book depreciation reserve. The theoretical book depreciation reserve reflects the size of the book depreciation reserve if the proposed depreciation parameters (average service lives, survivor curves, remaining lives, and net salvage ratios) had been in place over the entire asset lives. The depreciation reserve surplus indicates that PEF has charged depreciation expense that is higher than necessary and has, in effect, recovered its investment in utility assets from customers too quickly.

Q IS PEF PROPOSING AN AMORTIZATION OF THE SURPLUS RESERVE BALANCE?

A No. PEF has utilized its actual book depreciation reserves to calculate its depreciation rates. In essence, PEF is returning its accumulated depreciation reserve to its customers over 21 years – the average remaining life of its utility assets.

Q DO YOU RECOMMEND THAT PEF'S CALCULATED RESERVE SURPLUS BE AMORTIZED OVER A SPECIFIC PERIOD?

A Yes. Because the reserve surplus is so significant, I am conservatively recommending that approximately one-half of the remaining excess reserve, or

$250 million, be amortized over a five-year period. This is a conservative recommendation because it would be reasonable to recommend amortizing all of the remaining reserve surplus on an accelerated basis. This reduces depreciation expense by $50 million. The portion of the reserve that is not amortized should be utilized to develop the book depreciation rates, and be passed back to customers over the remaining asset lives of 21 years.

Q **HAVE YOU ESTIMATED THE IMPACT OF AMORTIZING $250 MILLION OVER FIVE YEARS?**

A Yes. Amortizing $250 million over five years would reduce PEF's depreciation expense by $50 million. However, this expense reduction would be, in part, offset by an increase in the investment to be recovered in depreciation rates and would increase the depreciation rates proposed by PEF by $11.7 million.

As a result, as shown on my Exhibit MPG-17 the net effect of this adjustment would be an approximate $38.3 million reduction to PEF's proposed depreciation expense, of which $33.6 million is retail. This assumes all of PEF's other depreciation recommendations are accepted.

Q **HAVE YOU PERFORMED A SPECIFIC CALCULATION TO DETERMINE THE IMPACT OF YOUR ADJUSTMENT ON PEF'S DEPRECIATION EXPENSE?**

A No. I have not performed a specific calculation that deals with all of PEF's plant accounts, but I have attempted to estimate what this impact would be. It is my understanding that other parties in this case will be addressing certain depreciation issues; therefore, depending on the Commission's final ruling, it may be necessary for PEF to recalculate the rates in a compliance filing.

T&D Net Salvage

Q ARE YOU ADDRESSING ANY OTHER DEPRECIATION ISSUES?

A Yes. I am addressing the level of net salvage that PEF has included in depreciation rates for its transmission and distribution plant accounts. I recommend PEF's proposed depreciation rates be reduced to lower its annual depreciation rates by $43.0 million total electric, and $41.8 million retail electric, in order to eliminate T&D net salvage expense included in PEF's proposed new depreciation rates. As set forth below, I believe this is appropriate because the Company's proposal will substantially overcollect T&D net salvage costs from current customers and undercollect net salvage costs from future customers. While this benefits future generations of customers, it is detrimental to current customers. This intergenerational shift is not just and reasonable and should be rejected.

Q PLEASE DEFINE WHAT IS MEANT BY NET SALVAGE.

A Net salvage is simply the value received from the sale or reuse of retired property (salvage value), less the cost of retiring such property (cost of removal). Net salvage can be either positive or negative. If the salvage value exceeds the cost of removal, the net salvage is positive. If the cost of removal is greater than the salvage value received as a result of retirement, the net salvage is negative. PEF calculated for each T&D account a gross salvage rate and a cost of removal rate. These two rates are added to the plant depreciation rate to produce the total book depreciation rate.

Q WHY DO YOU TAKE EXCEPTION TO PEF'S PROPOSED NET SALVAGE COST REFLECTED IN ITS PROPOSED DEPRECIATION RATES?

A The annual net salvage component of depreciation expense that PEF is requesting is significantly greater than its actual net salvage expense experience. As a result, the depreciation rates and resulting depreciation expense are overstated and, thus, not just or reasonable.

The consequences of PEF's proposed net salvage costs are that it unnecessarily raises rates for today's customers and will lower rates to future customers. This intergenerational subsidization is unreasonable. This shift in cost burden occurs because the net salvage that PEF has included in its proposed depreciation rates includes an estimate of future inflation.

Q DO YOU BELIEVE PEF'S CURRENT NET SALVAGE RATIOS PRODUCE DEPRECIATION RATES AND EXPENSE THAT ARE EXCESSIVE?

A Yes. This is based on a comparison of the net salvage expense included in PEF's proposed T&D depreciation expense with the level of net salvage expense PEF actually experiences. PEF's proposed depreciation expense contains an annual net salvage component of $43 million. PEF determined net salvage by applying its gross salvage rates and the cost of removal to the 12/31/2005 plant balances. However, PEF's average actual annual T&D net salvage expense over the last five years is a negative $600,000. This means that over the last five years cost of removal has barely exceeded the gross salvage value.

Q PLEASE EXPLAIN HOW YOU DETERMINED THE DEPRECIATION EXPENSE THAT IS ASSOCIATED WITH NET SALVAGE.

A To calculate the net salvage, I applied PEF's proposed net salvage rates, which are composed of the gross salvage and cost of removal rates, to the 12/31/2005 plant balance. The result of the analysis is summarized on my Exhibit MPG-18

Q HOW DOES PEF'S HISTORICAL ACTUAL NET SALVAGE COMPARE TO THE LEVEL OF NET SALVAGE THAT PEF IS PROPOSING TO INCLUDE IN ITS DEPRECIATION RATES?

A Table 2 below shows PEF's actual annual net salvage experience over the last ten years for those T&D accounts that have a proposed net salvage ratio. As Table 2 shows, over the last five years PEF's net salvage experience has averaged a negative $600,000 per year. Over the past ten years, the average annual net salvage expense has been a negative $590,000 per year. (The amounts shown in Table 2 were developed from the data provided in PEF's filing.) A negative net salvage expense means that the cost of removal has exceeded the gross salvage value.

TABLE 2

PEF's Net Salvage by Account

Account No.	Net Salvage 5-Year	Net Salvage 10-Year
Transmission Plant		
352.00	$ (790)	$ (4,874)
353.10	315,403	799,340
354.00	(660)	213
355.00	314,871	83,065
356.00	173,042	113,576
358.00	-	(156)
Total Transmission	$ 801,867	$ 991,162
Distribution Plant		
361.00	$ 1,497	$ (510)
362.00	230,359	415,040
364.00	(525,984)	(809,308)
365.00	80,103	154,314
366.00	(121,430)	(64,720)
367.00	(452,495)	(517,771)
368.00	(109,404)	(285,175)
369.10	(29,970)	(392,548)
369.20	(41,915)	110,865
370.00	(170,301)	(70,206)
373.00	(271,103)	(121,404)
Total Distribution	$ (1,401,643)	$ (1,581,423)
Total Transmission and Distribution	$ (599,776)	$ (590,261)

As previously stated, PEF's proposed depreciation rates include $43 million per year of net salvage expense. Clearly, charging current customers for $43 million a year of net salvage costs, when the Company is expending less than $1 million a year, creates an unreasonable and excessive burden on current customers.

Q WHAT CAUSES THE DISPARITY BETWEEN NET SALVAGE EXPENSE INCLUDED IN DEPRECIATION RATES AND ACTUAL NET SALVAGE EXPERIENCE?

A Proposed net salvage percentages that are included in the development of depreciation rates reflect estimates of future inflation and also may not capture economies of scale that would occur if large retirement activity occurred during a single year.

Q YOU INDICATED THAT THE DISPARITY BETWEEN THE NET SALVAGE EXPENSE INCLUDED IN DEPRECIATION RATES AND PEF'S ACTUAL NET SALVAGE EXPERIENCE IS PRODUCED BY THE FACT THAT THE NET SALVAGE COMPONENT INCLUDED IN THE DEPRECIATION RATES INCLUDES THE IMPACT OF FUTURE INFLATION. PLEASE ELABORATE.

A To develop the net salvage component of the depreciation rates, PEF analyzes the net salvage cost it experiences when retiring plant investment. In addition, PEF contends that the proposed net salvage ratio reflects "future expectations." Because of the magnitude of the proposed level of net salvage expense as compared to historic levels, it can only be assumed that future escalation is included in the estimates.

Q PLEASE PROVIDE AN EXAMPLE OF THE IMPACT ON NET SALVAGE ASSOCIATED WITH INCLUDING FUTURE INFLATION IN THE DEVELOPMENT OF NET SALVAGE RATIOS.

A For Plant Account 366, PEF is proposing a net salvage ratio of a negative 25% and an average service life of 33 years. In its proposal, PEF is requesting $250 of net salvage expense for every $1,000 of investment. If we simply discount the $250 at a 3% inflation rate for 33 years, the present-day cost to remove that asset is approximately $94. Under PEF's proposal, today's customers would essentially see a 33-year amortization of the $250 in their depreciation rates. As a result, PEF would require today's customers to pick up a portion of the cost of inflation that it estimates will occur over the next 33 years.

Q DOES THE COMPANY'S PROPOSAL TO REFLECT FUTURE INFLATION IN ITS COST OF SERVICE TODAY HARM CURRENT CUSTOMERS?

A Yes. Future inflation will over time also increase Florida retail customers' disposable income. Hence, paying higher amounts of inflation adjusted net salvage cost in future periods will be less of a burden because households' disposable income will also likely increase by inflation gains, thus mitigating the burden on households' disposable income in meeting their future obligations to the utility. Also, Florida businesses are more able to afford future inflation adjusted increased costs of production with future inflation adjusted prices they receive for their own goods and services. Hence, net salvage costs should be based on current costs, not inflation adjusted costs.

Q WHAT IS THE IMPACT ON THE VARIOUS VINTAGES OF CUSTOMERS OF INCLUDING PEF'S PROPOSED NET SALVAGE RATIOS IN THE DEVELOPMENT OF THE DEPRECIATION RATES?

A With PEF's proposal, future customers benefit substantially. Accrued depreciation is an offset to rate base. As accrued depreciation builds up, the rate base becomes smaller. Smaller rate base means that the return requirement and associated income taxes become less over time. Because of this ratemaking consequence, future customers benefit substantially by including PEF's proposed net salvage ratios in the determination of depreciation rates.

As noted above, PEF is proposing an average service life of 33 years and a net salvage ratio of a negative 25% for Account 366. As a result, every year PEF would be accruing depreciation expense, on average, at a rate of 3.79% (1.25/33). After 26.5 years of service, the Account 366 investment is fully depreciated. Therefore, for the last 6.5 years, or 20% of the asset's life, the rate base is negative. After year 35, the customers who are utilizing the assets are no longer paying a return and associated taxes.

Q HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE REVENUE REQUIREMENT ASSOCIATED WITH A $1,000 INVESTMENT IN ACCOUNT 366?

A Yes. My Exhibit MPG-19 shows the development of the annual revenue requirement over an average life span of 33 years. The Exhibit assumes that the $1,000 is placed in service and is retired at the end of the year 33. The revenue requirement includes both the return of investment, which is depreciation expense, and the return on investment, which includes a component for return and income taxes. A pre-tax rate of return of 10% was utilized for purposes of making the calculation.

As Exhibit MPG-19 shows, after year 11, over 50% of the total return "of" and "on" this investment is paid. That is, over approximately 25% of the useful life half of the revenue requirement associated with the return on and of investment is collected from customers. As a result, during the last 75% of the asset's life, future customers benefit by the inflated rates paid by current customers.

If the same analysis is performed on a present value or real dollar basis, over 50% of the revenue requirement associated with the return of and on investment is paid over approximately a six-year period.

Q WHAT DO YOU PROPOSE IN THIS PROCEEDING?

A I propose the Commission eliminate the net salvage ratios from the T&D depreciation rates. The net salvage expense that is included in PEF's ratemaking revenue requirement should be based on current net salvage experience. As shown on Table 2, the average net salvage expense over the last five years is negative $600,000 per year. Dividing this by the T&D plant produces a net salvage ratio of less than a negative 0.1%. Therefore, based on a review of PEF's historic net salvage expense, less than $1 million is warranted. However, because PEF has excess depreciation reserves, I am recommending a zero net salvage for purposes of calculating the T&D depreciation rates.

Q IS THERE SUPPORT IN ANY INDUSTRY TRADE PUBLICATION FOR EXCLUDING NET SALVAGE RATIOS FROM THE DEVELOPMENT OF DEPRECIATION RATES?

A Yes. Pages 157-158 of the Public Utility Depreciation Practices published in August 1996 by the National Association of Regulatory Utility Commissioners (NARUC) states:

> "Some commissions have abandoned the above procedure and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred.
>
> Determining a reasonably accurate estimate of the average or future net salvage is not an easy task; estimates can be the subject of considerable discussions and controversy between regulators and utility personnel. This is one of the reasons advanced in support of current-period accounting for these items. When estimating future net salvage, every effort should be made to ensure that the estimate is as accurate as possible. Normally, the process should start by analyzing past salvage and cost of removal data and by using the results of this analysis to project future gross salvage and cost of removal."

This indicates that excluding net salvage from the depreciation rates is consistent with the method used by other jurisdictions and is acceptable to NARUC.

Q WHAT IS THE IMPACT ON PEF'S REVENUE REQUIREMENT AS A RESULT OF YOUR PROPOSED TREATMENT OF NET SALVAGE FOR THE PLANT ACCOUNTS?

A Removing the net salvage from the depreciation rates reduces PEF's requested depreciation expense by $43.0 million, or $42.0 million on a retail basis.

FOSSIL UNIT DISMANTLEMENT EXPENSE

Q IS PEF PROPOSING TO INCLUDE A FOSSIL GENERATING UNIT DISMANTLEMENT EXPENSE IN ITS COST OF SERVICE?

A Yes. PEF is proposing an annual fossil dismantlement accrual beginning in 2006 of $11.2 million total system, and $9.6 million retail. This is an increase to PEF's cost of service because it agreed to discontinue accruing a fossil dismantlement expense in its last rate case settlement.

Q IS PEF'S PROPOSAL FOR A DISMANTLEMENT EXPENSE ACCRUAL IN THIS PROCEEDING REASONABLE?

A No. Its dismantlement accrual is based on the estimated direct costs of dismantling and disposal of each facility, offset by the expected scrap value. The Company's study ignores the value of land and the potential replacement generation being developed on these existing fossil station sites. Hence, there is significant salvage value at these facilities that is not accurately reflected in the fossil station dismantlement accrual proposal. Accordingly, PEF's proposal for fossil station dismantlement costs is unreasonable and should be rejected.

Q SHOULD PEF HAVE REFLECTED THE EXPECTATION OF EXISTING FOSSIL STATION SITES BEING USED FOR REDEVELOPMENT OF GENERATING ASSETS OR REFLECTED THE LAND VALUE OF THOSE SITES IN ITS DISMANTLEMENT COST ESTIMATE?

A Yes. PEF based its recommendations on dismantling studies that do not recognize the value of the generating sites. A generating site should be valuable because the sites have access to the electric transmission system. Because of this access, these sites should be valuable to PEF and/or an independent power producer for the next generation of power plants. This should provide a positive benefit that needs to be considered when a net salvage value is developed.

Finally, these sites also have infrastructure in place that should make these sites valuable. For example, the sites have access to water, railroads, and/or roads, all of which provide value to the existing generating sites. Also, the costs associated with siting and permitting a major electric generating plant at an alternative site could enhance the value of the current sites. Therefore, if these types of positive salvage considerations are included in the estimate to determine the net salvage, the dismantling studies would have to be adjusted, and the dismantlement costs would disappear.

Q **BECAUSE LAND IS NOT A DEPRECIABLE ASSET, SHOULD IT BE EXCLUDED FROM THE DETERMINATION OF FOSSIL DISMANTLEMENT STUDIES?**

A No. The fact that land is not depreciable has no bearing on the determination of net salvage value or net dismantling costs for fossil fuel generating plants. Customers pay a return on the land during the entire period that the generating plant was classified as plant in service. In addition, in some instances customers also paid a return on land during the time period it was included as plant held for future use. Also, the customers have paid for all of the maintenance and upkeep of the site. Improvements to the site, which include roads, railways, utilities and access to the electric transmission system, have increased the value of the site.

The customer has also paid for all of the property taxes associated with the land. Simply put, the customer has reflected in its rates all of the costs associated with the investment in the land. The notion that any potential gross salvage value associated with the site is solely land-related and should not be reflected in the determination of the net salvage value is erroneous and leads to the unreasonable cost estimates of dismantlement.

Q **HOW COULD PEF RECOVER ITS FOSSIL DISMANTLEMENT COST IF IT DOES NOT ACCRUE A CHARGE?**

A The cost of dismantlement should either be included as a part of the cost of redevelopment of the generating sites for future generation assets, or should be recovered through the sale of the land.

NUCLEAR DECOMMISSIONING RESERVE REFUND

Q **PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT RELATED TO NUCLEAR DECOMMISSIONING EXPENSE.**

A I recommend the Company refund to customers over the next five years the amount of money set aside in its non-tax qualified decommissioning trust fund, which is approximately $75 million.

Q **WHY SHOULD THE COMPANY REFUND THE AMOUNT OF MONIES DEPOSITED IN ITS NON-TAX QUALIFIED DECOMMISSIONING TRUST TO CUSTOMERS?**

A The Company currently has substantially overcollected from customers the amount needed to meet its nuclear decommissioning obligation. Hence, it would be reasonable to refund to customers these overcollections of decommissioning costs.

Q PLEASE DESCRIBE WHY YOU BELIEVE THE COMPANY HAS EXCESS RESERVES FOR NUCLEAR DECOMMISSIONING IN ITS DECOMMISSIONING TRUST FUND ACCOUNT.

A This is evident from the Company's own decommissioning trust fund study. Even without making annual contributions to the decommissioning trust fund accounts, the Company has funding adequate to more than cover the projected cost of decommissioning Crystal River Unit 3, including a 17.3% cost contingency factor. Indeed, based on the Company's own study, included as an exhibit to PEF witness Dale E. Young's testimony, Exhibit No. __ (DEY-4), the amount of money included in the Company's decommissioning trust fund right now will fully recover the projected cost of decommissioning, including the contingency reserve, and will maintain an excess balance after full decommissioning of approximately $3.6 billion.

On a current year basis, the Company projects that for calendar year 2005 it requires an amount in decommissioning trusts of approximately $268.8 million to fully meet its decommissioning obligation. However, the Company has approximately $370.3 million deposited in its nuclear decommissioning trust. Hence, PEF's decommissioning trusts are overfunded by more than $100 million.

Q PLEASE DESCRIBE THE COMPANY'S DECOMMISSIONING TRUSTS.

A The Company has two decommissioning trusts, a tax qualified trust, and a non-tax qualified trust. As the names imply, the difference between the two trusts relates to the income tax payable on the earnings from the trust fund assets. At end of calendar year 2004, the Company had $74.9 million in its non-tax qualified trust, and $285.7 million in its tax qualified trust.

Q WHY DO YOU RECOMMEND REFUNDING EXCESS DECOMMISSIONING RESERVES?

A Refunding the Company's excess decommissioning reserves is appropriate for several reasons. First, the Company simply has excess funding for this expected cost of service. It is economically inefficient for the Company to retain these customer provided funds that exceed the explicit cost of decommissioning.

Second, refunding these decommissioning funds will ensure that current generations of customers that made the excess contributions to the decommissioning trust receive a credit for the excess funding in those trusts. Hence, delaying the refund of excess decommissioning contributions will benefit future generations of customers, rather than the generation of customers that actually made the decommissioning contributions.

Q IF PEF DOES REFUND EXCESS DECOMMISSIONING RESERVES, WILL IT HAVE ADEQUATE ASSURANCE THAT DECOMMISSIONING FUNDING WILL BE AVAILABLE TO FULLY AND SAFELY DECOMMISSION CR3?

A Yes. Based on the Company's current cost projections, the amount of money included in its tax qualified decommissioning trust will fully fund decommissioning of CR3. Further, to the extent the cost of decommissioning changes, or investment returns on the trust are not as expected, PEF can charge future generations of customers for making additional contributions to the tax qualified decommissioning trust. This would be appropriate because it would transfer part of the cost of decommissioning to future generations of customers. Future generations of customers would not be burdened by making contributions to CR3's decommissioning, because they will be receiving benefits of CR3's low production costs as long as CR3 remains in service. Hence, this would create an appropriate allocation of CR3 costs among generations of customers. This is efficient and fair cost sharing.

Q WHAT IS THE IMPACT ON PEF'S CURRENT COST OF SERVICE FROM REFUNDING NON-TAX QUALIFIED DECOMMISSION TRUST FUND BALANCES?

A As of end of year 2004, PEF had $74.9 million in its non-tax qualified decommissioning trust. I recommend this balance be refunded to customers over a five-year period. Further, in order to ensure that the money is available, I would recommend the Commission direct PEF to liquidate this decommissioning trust and use the net proceeds to reduce the carrying cost of rate base. Hence, the impact on revenue requirements will be twofold: (a) the after tax amount of the non-tax qualified decommissioning fund amortization would reduce expenses, and (b) carrying charges on PEF's rate base would be reduced over the amortization period.

Q PLEASE DESCRIBE YOUR ASSUMPTION IN ESTIMATING THE IMPACT ON PEF'S COST OF SERVICE FROM REFUNDING THE NON-TAX QUALIFIED DECOMMISSIONING TRUST FUND ASSETS.

A I estimate the reduction in cost of service to be $17.65 million per year. This is developed on my Exhibit MPG-20. I develop this cost of service estimated adjustment as follows.

First, I assumed that if PEF liquidates its non-tax qualified decommissioning trust, it would incur a consolidated tax expense from this liquidation of 20%. (This liquidation tax expense and the credit to PEF's cost of service should be updated to reflect PEF's actual tax cost.) This tax payment would reduce the $74.9 million trust balance to a net cash proceed to PEF of $59.9 million.

I recommend that PEF then amortize the $59.9 million net cash proceeds back to customers over a five-year period and PEF be allowed to retain the unamortized balance as a rate base reduction. This amortization would reduce PEF's cost of service by $11.98 million and reduce its net operating income and income taxes.

PEF's net operating income and income tax expense would be reduced by reflecting the unamortized balance as a rate base reduction. The rate base reduction related to the unamortized balance of this cash is based on the average unamortized test year balance of $53.9 million, and the Company's rate of return reflecting income tax expense. Using my proposed capital structure and a 9.8% return on equity results in a pre-tax rate of return of 10.51% and would reduce net operating income and income tax expense by $5.67 million per year.

Hence, the total reduction to PEF's cost of service would be the annual amortization credit of $11.98 million, and the reduction to its net operating income and income tax expense of $5.67 million, for a total revenue requirement reduction of $17.65 million.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

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BEFORE THE

PUBLIC SERVICE COMMISSION OF FLORIDA

In re: Petition for rate increase by Progress Energy Florida, Inc.	Docket No. 050078-EI

Direct Testimony of Thomas J. Regan, Jr.

Q. State your name and business address.

A. My name is Thomas J. Regan, Jr. My business address is:

Potash Corp
1101 Skokie Blvd., Suite 400
Northbrook, IL 60062

Q. What is your position with PCS Phosphate (PCS) and what are your duties in that position.

A. I am President of PCS Phosphate division. My principal responsibilities include all of the operating locations, including the White Springs facilities. I have responsibility for the safety, environmental, quality and cost performance of each of these locations.

Q. Briefly describe your professional and educational background and your work experience.

A. I have a Bachelor of Science degree in Chemical Engineering from Pennsylvania State University granted in 1968. I have done graduate work in Finance at Marietta College, Ohio University, West Virginia University and McNeese State. I have also attended an Executive Management program at Columbia University. I have been involved in the mining and chemical business for 37 years, with principal participation in the manufacturing and mining operations. My primary responsibilities include ensuring site contribution to profitability and cost control.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe PCS and its operations and to explain the serious adverse effect that PEF's rate proposal would have on PCS operations in Florida.

Potash Corporation of Saskatchewan's (PCS) Operations

Q. Please describe PCS and its operations.

A. PCS Phosphate is a division of PCS Corporation, whose other divisions include PCS Potash, PCS Nitrogen and PCS Sales. By capacity, PCS Corporation is the world's larges potash manufacturer, the fourth largest nitrogen manufacturer and the third largest phosphate manufacturer.

Q. Describe PCS' operations in the PEF territory.

A. PCS Phosphate has one manufacturing facility in White Springs, Florida, at which it conducts both mining and chemical processing operations and employs approximately 950 people. It makes a property and sales tax contribution to the local and state economy of more than $5 million per year.

Q. In addition to Florida, where else does PCS have operations?

A. PCS Phosphate has a similar manufacturing facility in Aurora, N.C. Other manufacturing facilities are located in Illinois, Nebraska, Missouri, Louisiana, Ohio and Brazil. Other PCS divisions have locations throughout the US, Canada and South America. PCS competes for sales on a world-wide basis.

Effect of PEF's Proposal on PCS

Q. From the perspective of one of PEF's largest customers, what do you think of the PEF rate filing.

A. Fundamentally, I believe that (1) the PEF revenue increase is entirely unjustified and (2) PEF's rate proposals are ill-advised and harmful to its industrial customers. White Springs was sufficiently troubled by PEF's rates that it retained its own experts to analyze PEF's filing and to submit testimony in this proceeding. Based on that analysis and testimony, it is apparent that, if anything, the Commission should order a PEF revenue decrease. Moreover, as White Springs' witnesses explain in some detail, PEF's cost allocation and rate proposals are quite harmful to industrial customers. First, those proposals allocate a disproportionate amount of costs to industrial customers. Second, PEF's proposal to eliminate the IS-1 and IST-1 rate schedules would have a severe and unjustified adverse impact on industrial customers such as White Springs.

Q. Do you agree that customers have benefited from the fact that PEF has not had a base rate increase since 1993?

A. No, I do not. As White Springs witness Gorman explains, to a large degree PEF has not needed a base rate increase because of various economic factors beyond PEF's control, such as falling interest rates. Moreover, as explained by Mr. Chalfant it appears that PEF is currently collecting revenues significantly in excess what is required, and has been doing so for a number of years.

Q. How do PEF's rate compare to those of other utilities.

A. As Mr. Brubaker explains, PEF is a relatively high cost provider. For example, PEF's industrial rates are the second highest of utilities surveyed in the Southeastern United States. An interesting comparison can be made between White Springs and the PCS Aurora, North Carolina facility. Both facilities produce similar products, and thus in a sense compete with each other, and the

Aurora facility is served by PEF's affiliate Progress Energy Carolina. For many years PEC's rates for our Aurora facility have been significantly lower than PEF's rates for White Springs. In our discussions with PEF they have not provided any plausible reasons for this discrepancy.

Q. Do you believe that PEF should be rewarded for being an efficient utility?

A. Absolutely not. As can be seen in Mr. Brubaker's testimony, PEF is a high cost supplier. PEF cannot evade that fact through creative economic models and statistics. From the perspective of a large industrial customer I do not view PEF as a particularly efficient supplier. Indeed, PEF appears largely insensitive to the economic concerns of its industrial customers.

Q. Under what rate schedules does PCS currently take service from PEF?

A. PCS takes service primarily under PEF's IS-1 and IST-1 tariffs, but also has two cogeneration (from waste heat) plants that receive some power under a SS-2 tariff.

Q. PEF has proposed to eliminate the IS-1 tariff. What effect will this have on PCS?

A. PEF has proposed to eliminate the IS-1 and IST-1 rates and to transfer customers currently receiving service under these rates to the IS-2 and IST-2 rate schedules. That change would have a dramatic adverse impact on White Springs. Because the level of interruptible credits would be greatly reduced under the PEF proposal, the real base rate increase to White Springs' interruptible service would be approximately 84 percent.

Q. What impact do electric power costs have on PCS' decisions regarding whether to operate a facility in Florida?

A. Electrical power cost is factored into our economic evaluations when we are determining whether to operate facilities such as our White Springs Suwannee River Chemical Complex, ramp up production of operating facilities such as our White Springs Swift Creek Mine, or build new plants in the state. These types of evaluations compare the economics of increasing production at White Springs versus using or expanding our facility in North Carolina or elsewhere outside of Florida. If the IS-1 rate is eliminated as PEF proposes, any plans for future production increases in Florida would be at a further competitive disadvantage when compared to North Carolina or elsewhere in regards to power costs. Similarly, an unjustified revenue increase or inappropriate cost allocation methods would further disadvantage White Springs.

Q. What are your thoughts on PEF's interruptible rates?

A. I can give you White Springs' perspective on the issue. It cannot be assumed that industrial customers would be able to pay higher firm rates in the absence of viable interruptible rates notwithstanding that we are struggling under current competitive pressures. All things being equal, PCS would like to have affordable firm service rather than the interruptible service that we must accept in order to remain competitive. In fact, Mr. Brubaker's testimony demonstrates, at Exhibit MEB-1, that utilities in other states have firm industrial rates that are lower than the interruptible rates that White Springs pays today.

Our company long ago recognized the difficulty in remaining competitive under firm rates, and so went to interruptible rates, despite the disruptions to our operations. We have also already changed operations at our plants to lower electrical costs, in order to remain competitive. We have even added self-generation capability to defray electrical costs, at a significant capital and maintenance investment. Despite these changes, many phosphate companies have already gone out of business in Florida because they could no longer compete. For these reasons, it is incorrect to assume that industrial customers could pay firm rates without significantly affecting consumption.

Q. How does the current IS-1 rate, which PEF proposes to eliminate, compare with similar rates at other PCS plants?

A. Even the current rate is higher. The PEF IS-1 rate is at a significant competitive disadvantage, for example, when compared to the rate under which our facility in Aurora, NC operates. During the last several years total rates for our Florida operations have been higher than for our North Carolina operations served by PEC. This circumstance provides an economic incentive to move parts of our load to North Carolina, to the economic detriment of our small north Florida community and to the consumers of Florida Power who benefit from the revenue our company provides to the system.

Q. Do you have any comments on Mr. Habermeyer's testimony?

A. Yes. Mr. Habermeyer's Direct Testimony asserts that PEF has achieved "top quartile performance in most key areas." From my perspective, there are two key areas of performance, cost and reliability, and PEF has performed below average in both. Regarding cost, Mr. Brubaker's testimony shows that PEF's industrial rates are the second highest in the Southeastern United States. This may be "top quartile" performance for PEF's shareholders, but from the perspective of large customers such as White Springs it is bottom quartile performance. In fact, PEF's attempt to raise our base rates, which are already high, by as much as 84 per cent represents a significant threat to our ability to compete in domestic and international markets. Regarding reliability, from White

Springs perspective PEF's performance has been at best mediocre. For example, over approximately one month in 2004 there were three outages in the 115 kV transmission line feeding our Suwannee River complexes. Another example of mediocre reliability is that our administration complexes are plagued with outages, to the point where we do not even bother tracking them. We average approximately one outage every 1 – 2 months during working hours, with each outage typically lasting 1 – 4 hours during working hours. While I do not address PEF's overall system reliability, the reliability of service to the White Springs facility is unsatisfactory.

Q. Do you have other concerns with PEF's rate filing.

A. Yes. Mr. Gorman observes in his testimony that PEF has collected hundreds of millions of dollars more than it needs purposes such as nuclear decommissioning. I do not understand why PEF is allowed to force its customers to provide such unneeded funds. The Commission should order PEF to return such funds to the customers that provided those funds. Certainly companies such as White Springs, which are facing tremendous competitive pressures, can find more productive uses for those funds than simply allowing them to sit unused and unneeded in PEF accounts.

Q. Does that conclude your testimony at this time?

A. Yes.

BEFORE THE

PUBLIC SERVICE COMMISSION OF FLORIDA

In re: Petition for rate increase by Progress Energy Florida, Inc.	Docket No. 050078-EI

Direct Testimony of Alan Chalfant

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (White Springs). White Springs is a manufacturer of fertilizer products with plants and operations located within Progress Energy Florida Inc.'s (PEF) service territory at White Springs, and receives service under numerous rate schedules. During calendar year 2004, White Springs purchased approximately $20 million of power from PEF.

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A I will address portions of the Direct Testimony of PEF witness Dr. Charles Cicchetti. Specifically, I will address Dr. Cicchetti's proposal to add 50 basis points to PEF's allowed rate of return on equity as a reward for past performance. In doing so I will discuss the competing concepts of cost of service and performance-based ratemaking, as well as Dr. Cicchetti's statistical analysis of PEF's recent performance.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS.

A My basic conclusion is that Dr. Cicchetti's proposal to "bump" PEF's allowed rate of return on equity by 50 basis points lacks credible support and should be rejected. That proposal violates the sound ratemaking principle that a regulated utility should be allowed the opportunity to recover only its costs which include a reasonable return on equity. Moreover, Dr. Cicchetti draws unwarranted conclusions regarding PEF's performance from his statistical analysis.

Q AS A GENERAL MATTER, DO YOU BELIEVE THAT PEF'S PERFORMANCE WARRANTS A RETURN ON EQUITY BONUS?

A Absolutely not. The Commission need look no further than a comparison of PEF's rates to those of other utilities in the Southeastern United States to see that PEF's claims of superior performance are hollow. As my associate, Mr. Brubaker demonstrates, PEF is one of the highest-cost suppliers in the region. Dr. Cicchetti's attempt to pick and choose performance metrics cannot change that fact. Neither can Dr. Cicchetti's secret (i.e., "proprietary") model that masks the fact that PEF is a high-cost supplier. As I discuss below, regulation serves as a surrogate for competition, and it is inconceivable that customers in a competitive market would reward a high cost supplier with an equity bonus. To the contrary, the competitive market would punish a high cost supplier – suggesting that if anything the Commission should impose an ROE penalty for PEF's poor performance relative to its peers.

Q PLEASE BRIEFLY DESCRIBE DR. CICCHETTI'S ARGUMENT FOR "BUMPING" PEF'S ALLOWED RATE OF RETURN.

A At page 51 of his direct testimony, Dr. Cicchetti recommends that the Commission add 50 basis points to the 12.3% ROE Dr. Vander Weide proposes on behalf of PEF "to reward PEF for its superior performance and encourage it to continue its efforts."

Q IS THIS A REASONABLE PROPOSAL?

A No. First, it is not reasonable to ask the Commission to "reward" PEF for its past performance. The "reward" for minimizing costs is the monopoly franchise granted to PEF and its predecessors. Second, there should be no need for the Commission to "encourage" PEF to minimize its costs in the future. Third, Dr. Cicchetti's statistical analysis falls short of demonstrating superior past performance.

Q WHY ISN'T IT REASONABLE FOR PEF TO ASK THE COMMISSION TO REWARD IT FOR PAST PERFORMANCE?

A PEF has done no more than the minimum that its customers and this Commission have a right to expect. As part of the implicit regulatory compact a utility is expected to provide reliable service at minimum cost in exchange for a monopoly franchise and the opportunity to recover its costs, including a reasonable profit, from Commission-approved rates. There is no reason that a utility should need to be bribed to keep its part of the bargain. This is particularly true here, where the performance that Dr. Cicchetti seeks to reward has resulted in some of the highest rates in the region – that certainly is not deserving of an ROE bonus.

Q **WHY SHOULD THE COMMISSION ATTEMPT TO EMULATE COMPETITION IN ESTABLISHING THE RATES UTILITIES ARE ALLOWED TO CHARGE?**

A Regulation has been relied upon as a surrogate for competition where the alternative would be a natural monopoly. Natural monopolies arise where one producer can achieve lower costs than two or more producers in the same market. Probably the best example of such economies of scale is the electric utility industry.

The regulatory compact or bargain represents a solution that avoids charging customers for monopoly profits while, at the same time, realizing the lower costs that result from a monopolist supplying the market. The benefit to the supplier is that, because it is granted a monopoly franchise, its risk of not earning a reasonable profit is reduced. Customers benefit because they are assured of adequate supplies of the product at the lowest cost.

The Commission, of course, plays a critical role in enforcing this regulatory compact. Absent Commission vigilance, a regulated utility such as PEF could extract monopoly rents from its customers by charging higher rates than a competitive market would permit. That is precisely what PEF is trying to accomplish through, among other things, its proposal to "bump" an already excessive return on equity by an additional 50 basis points.

Q BUT DOESN'T COMPETITION ALSO PROVIDE ADDITIONAL REWARDS FOR ENTITIES THAT ARE ABLE TO LOWER THEIR COSTS MORE THAN OTHERS?

A Yes, for very short periods, not unlike the situation encountered by a utility that reduces its costs or increases efficiency between rate cases. But there are several factors to consider. First, an entity in the competitive market may have the opportunity to increase its profits if it is more efficient than its competitors, but it is also at risk that its profits will be lower – or that it will incur a loss – if it doesn't perform well. Significantly, customers in the competitive market do not care about isolated performance metrics and secret models – they turn to the lowest cost supplier, and punish suppliers that are either high cost or low quality. Moreover, competition also includes the very forces which ensure that such extra rewards are short-lived. Improvements in operating efficiencies by one firm will soon be matched by its competitors or those competitors will quickly disappear to be replaced by more efficient new firms. Thus, competition does provide incentives and rewards for efficiency and innovation but they are one-time and not perpetual pensions.

Q DR. CICCHETTI STATES AT PAGE 9 OF HIS DIRECT TESTIMONY THAT "THESE PAST EFFORTS TO IMPROVE EFFICIENCY AND PRODUCTIVITY SHOULD NOT BE USED, AS SOME WOULD LIKELY PROPOSE, IN A MANNER THAT TAKES AWAY THE INCENTIVE OF UTILITY SUCCESS AND PASSES IT ON TO RATE PAYERS." DO YOU AGREE WITH THAT STATEMENT?

A No. Underlying Dr. Cicchetti's testimony is a disturbing concept that PEF is entitled to all of the profits that it can achieve. I believe that Dr. Cicchetti has it exactly backwards: regulation exists to protect customers from the power of the monopoly utility supplier, not to ensure that the monopoly utility can extract the maximum profit from its customers. Moreover, there are at least three additional problems with Dr. Cicchetti's statement. First, returning to a cost based revenue requirement does not "take away" the benefits that PEF has already received for any efficiencies. Second, the ability to retain additional profits between rate cases provides a strong incentive for PEF to find additional efficiencies. Third, as in a competitive market, ratepayers should, indeed, be the ultimate beneficiaries of any savings.

Q **WHAT BENEFITS HAS PEF RECEIVED FOR ITS EFFICIENCIES?**

A As Dr. Cicchetti points out at page 9 of his direct testimony, PEF made certain promises and set certain goals in connection with its proposed merger. At least in part based on these promises the Commission approved that merger. That in itself should be sufficient benefit for the Company. It was a bargain: If the Commission approved the merger, the Company would meet certain goals. The Commission did approve the merger and the Company claims it has met its goals. That completes the bargain. No more should be required. For the Company to now say it wants more in the form of perpetual rewards for keeping its side of the bargain is disingenuous.

But PEF has, in fact, received additional monetary benefits in recent years. Dr. Cicchetti notes at page 46 of his direct testimony that "Adjusting for storm damage and other developments, PEF has been earning about 13.3% on equity on a corrected basis." Ignoring Dr. Cicchetti's corrections, the Company is presently earning approximately 14.9% on equity. My associate, Mr. Gorman, has calculated that a change in the return on equity of 1% has a revenue impact of $44 million. Thus, comparing the present earnings to the amount Dr. Vander Weide has determined is reasonable -- 12.3% -- suggests that PEF is currently receiving a reward of more than $114 million per year of revenue in excess of costs. Comparing the present earnings to the more reasonable return on equity recommended by Mr. Gorman -- 9.8% -- indicates that the present excess revenues are approximately $225 million per year. The inescapable conclusion is that PEF has been rewarded handsomely for a number of years.

Q **IF THE COMMISSION WERE TO RESET PEF'S REVENUES TO COST AT THIS TIME WILL THAT REMOVE THE INCENTIVE TO LOWER COSTS IN THE FUTURE?**

A Certainly not. The rewards that PEF has earned in recent years will not soon be forgotten. PEF knows that by realizing cost savings in the future it can again earn substantial rewards. Any savings it achieves relative to the level of costs established in this case will be realized as excess earnings until rates are reset in a future rate case. As long as this regulatory lag is kept to a minimum and the Commission requires new rate proceedings whenever earnings exceed the allowed level, this properly emulates the working of a competitive market where firms are rewarded for cost savings for a short period while their competitors adjust their costs. Competition does not allow perpetual rewards and neither should regulation.

Q **WHY DO YOU DISAGREE WITH DR. CICCHETTI'S STATEMENT THAT THE BENEFITS SHOULD NOT BE PASSED ON TO RATEPAYERS?**

A The great benefit of competition is that it forces costs to their lowest levels to the benefit of consumers who pay only the costs (including reasonable profits) of production. In a regulatory framework where the attempt is to emulate competition the results should be the same. Except for very short periods, the customers should be the beneficiaries of lower costs and utilities are obligated by the regulatory compact to provide reliable service at the lowest possible cost.

Q **AT PAGE 44 OF HIS TESTIMONY, DR. CICCHETTI TOUTS THE USE OF PERFORMANCE-BASED RATEMAKING. ARE YOU FAMILIAR WITH THAT CONCEPT?**

A Yes.

Q **IS THERE ANYTHING MISSING FROM DR. CICCHETTI'S PROPOSED APPLICATION OF THAT CONCEPT IN THIS CASE?**

A Yes. Any even-handed application of performance-based ratemaking includes specific criteria for any adjustments above or below cost, and those criteria provide for symmetrical adjustments similar to competition. In other words, a utility that does something 10% better than the stated norm will be rewarded by the same amount as a firm that falls 10% short of the norm will be penalized. Dr. Cicchetti's proposal contains neither stated criteria nor a set of symmetric rewards/penalties. Rather, he simply judges that PEF should be allowed to earn a rate of return that is 50 basis points above the cost of equity.

Q DR. CICCHETTI REFERS TO AN ADJUSTMENT HE MADE TO THE RATES OF WISCONSIN ELECTRIC POWER COMPANY (WEPCO) IN 1979. HAVE YOU REVIEWED THE ORDER IN THAT CASE WHICH HE CITES IN FOOTNOTES 1 AND 9 IN HIS DIRECT TESTIMONY?

A Yes.

Q WAS THE ACTION TAKEN BY THE PUBLIC SERVICE COMMISSION OF WISCONSIN (PSCW) IN THAT CASE SIMILAR TO WHAT DR. CICCHETTI IS PROPOSING HERE?

A No. In that case WEPCO had requested a rate of return on equity of 14.5%. The three Commissioners adopted a return of 13.25%.

Q THEN ON WHAT BASIS CAN DR. CICCHETTI SAY AT PAGE 47 THAT HE ADDED 25 BASIS POINTS TO WEPCO'S RETURN ON EQUITY?

A The 25 basis point addition is to the 13.0% return that had been granted to utilities for some time prior to the WEPCO decision, as Dr. Cicchetti correctly explains. However, this is far different than a 50 basis point addition <u>to the rate of return proposed by the Company's rate of return witness</u>.

Q DR. CICCHETTI ALSO STATES AT PAGE 47 OF HIS DIRECT TESTIMONY THAT HE "REWARDED WISCONSIN ELECTRIC POWER COMPANY'S SUPERIOR PERFORMANCE (WHICH INCLUDED EMBRACING TARIFF REFORMS THAT BENEFITED CONSUMERS, COOPERATION WITH THE COMMISSION AND ITS STAFF, REDUCTION AND ELIMINATION OF

UNNECESSARY COSTS, AND A WELL MANAGED AND HEALTHY UTILITY)." WOULD YOU LIKE TO COMMENT ON THAT STATEMENT?

A Yes. In fact, most of Dr. Cicchetti's "reward" to WEPCO was based on rate design and had nothing to do with "superior performance" or "reduction and elimination of unnecessary costs." Prior to becoming a Commissioner, Dr. Cicchetti had been a vocal proponent of marginal cost pricing before the PSCW and elsewhere. WEPCO at the time was also a proponent of marginal cost pricing. In fact, in Dr. Cicchetti's Concurring Opinion he sets out what he refers to as "the criteria that I believe to be important for determining the rate of return on common stock equity." He then sets forth three criteria at page 13-14. Under his first criteria he states:

> (1) A utility that carries a small percent of equity relative to its debt and preferred stock is holding down the before (and after) taxes cost of capital for its ratepayers. These firms should expect a higher than average rate of return. . . ."

His second criteria states in part:

> (2) . . . Utilities who, for whatever reason, contribute to a delay in the adoption of marginal cost based tariffs, should accept the fact that their preference for a more certain gross revenue target at the expense of more secure earnings for their stockholders and better choices based upon proper price signals for their customers, will mean that I will vote for lower rates of return because such utilities are less risk oriented and inert. . . ."

His third criteria also deals with rate design.

> (3) . . . Rate design delays caused by a utility company should therefore not be rewarded either with these specific forms of adjustment or with rates of return in the upper part of the 12 to 13½ percent range. . . .

The entire WEPCO Order and Dr. Cicchetti's Concurring Opinion are attached, hereto, as Exhibit AC-1.

Q **DR. CICCHETTI'S FIRST CRITERIA YOU NOTED ABOVE DEALT WITH THE UTILITY'S DEBT EQUITY RATIO. WHAT WAS THE PERCENT OF EQUITY APPROVED IN THAT ORDER?**

A 40%.

Q **WHAT BASIS IS GIVEN IN THE ORDER ITSELF IN SUPPORT OF THE 13.25% RATE OF RETURN?**

A The Order states at page 4:

> "In recognition of the increased proportion of revenue that is subject to consumer and market uncertainty as a result of the adoption of marginal cost and time of use rate structure and of the crucial need to maintain applicant's financial integrity during a period of capital expansion, the commission considers a return on common stock equity of 13.25% to be reasonable and just for purposes of this proceeding."

Thus, I found no support in the PSCW Order or Dr. Cicchetti's concurring opinion that suggests that WEPCO was being rewarded for "superior performance."

Q **ARE THERE ANY OTHER DIFFERENCES BETWEEN WHAT THE PSCW DID IN THE WEPCO CASE AND WHAT DR. CICCHETTI IS PROPOSING HERE?**

A Yes. The 13.25% return on equity in the WEPCO case represented the mid-point of the range of reasonableness of 13.00 to 13.50 proposed by the PSCW Staff in that case and, as noted above, well below WEPCO's requested return. Dr. Cicchetti's proposal here would result in a rate of return on equity over and above the proposal of the Company witness.

Q HAVE YOU REVIEWED DR. CICCHETTI'S STATISTICAL ANALYSIS OF PEF'S PERFORMANCE?

A Yes.

Q DO DR. CICCHETTI'S CONCLUSIONS CLEARLY FOLLOW FROM THE ANALYSIS?

A No. I was unable to trace the output of Dr. Cicchetti's statistical model, which was supplied in response to White Springs' Second Set of Requests for Production of Documents, No. 28, to the Tables in his testimony but I have no reason to expect that they are not numerically accurate. What is troublesome about Dr. Cicchetti's testimony is his characterization of the results.

In particular, Dr. Cicchetti refers frequently to the "minimum achievable cost" (e.g. page 21, line 6) and the costs of an "efficient firm within the industry." He states the conclusion at page 22, lines 2-3, that "PEF's actual costs for the period studied were 12.7% below the costs the model predicted for PEF for a three-year composite period."

While that statement seems to imply that PEF has somehow managed to achieve costs lower than the minimum we must dismiss that result as absurd. What it does mean, in fact, is simply that after eliminating the effect of numerous factors that contribute to costs, the costs achieved by PEF were 12.7% less than a "typical firm in the industry." (See, e.g., PEF's Response to White Springs' Second Set of Interrogatories, No. 33a). Of course, whether this is good or bad is highly dependent on the factors that are selected for inclusion in his model.

Q IF PEF WERE TRULY A LOW COST SUPPLIER SHOULD THAT BE REFLECTED IN ITS RATES?

A Yes. One would expect that a low cost supplier would have lower rates than other utilities in the region.

Q DO PEF'S RATES AS COMPARED TO OTHER UTILITIES IN THE SOUTHEAST SUGGEST IT IS A LOW COST SUPPLIER?

A No. As Mr. Brubaker demonstrates in his testimony, PEF is one of the highest cost suppliers in the Southeastern United States. Indeed, its firm industrial rates are 2nd highest in the group. (See Exhibits MEB-1, MEB-2 and MEB-3). This casts serious doubt on the relevance of Dr. Cicchetti's model.

Q DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications of Alan Chalfant

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Alan Chalfant. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and am a principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I hold a Bachelor's Degree in Mathematics from Northern Illinois University and the degree of Master of Arts in Economics from Washington University. From 1968 to 1973, I was Assistant Professor of Economics at California State University at Northridge, California. Among other courses in economics and statistics, I taught courses in the economics of antitrust and regulation at both the graduate and undergraduate levels. I have also taught courses at both graduate and undergraduate levels at California Lutheran College.

In 1973, I accepted a position with the Public Service Commission of Wisconsin in the Utility Rates Division. While at the Commission, I designed the rates for electric and natural gas utilities and aided in the preparation for cross-examination of witnesses representing utilities and intervenors before the Commission.

I joined the firm of Drazen-Brubaker & Associates, Inc. in September 1974 and became a Principal in that firm in 1988. In April 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff and currently has its principal office in St. Louis, Missouri, with branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Since 1974, I have been engaged in the preparation of studies relating to utility rate matters and have participated in numerous electric and gas rate cases. In total, I have participated in cases involving more than 60 electric utilities, 30 gas distribution utilities and 20 interstate pipelines.

Q **HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION OR A PUBLIC AUTHORITY?**

A I have testified before the Federal Energy Regulatory Commission and more than 30 state public utility regulatory commissions. In addition, I have appeared before a number of municipal regulatory bodies and courts.

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Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. Michael T. O'Sheasy, 5001 Kingswood Drive, Roswell, Georgia 30075. I am a Vice-President with Christensen Associates Energy Consulting, LLC.

Q. STATE BRIEFLY YOUR EDUCATION BACKGROUND AND EXPERIENCE.

A. I received a Bachelors degree in Industrial Engineering from the Georgia Institute of Technology in 1970. In 1974, I earned a Masters degree in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company – a division of the Carnation Company – as a plant superintendent in their Chamblee, Georgia operation. From 1975 to 1980, I worked for the John Harland Corporation, initially as an assistant plant manager, and then as a plant manager in their Jacksonville, Florida plant, and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions to the position of supervisor, during which time I began serving as an expert witness in costing. I have testified as Gulf Power Company's cost of service witness and have provided other support to Gulf in matters before the Florida Public Service Commission. In 1990, I became Manager of Product Design for Georgia Power Company, and I have testified before the Georgia Public Service Commission as an expert witness on rate design and pricing. I retired from Georgia Power Company on May 1, 2001, and became a consultant with Christensen Associates.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING

A. The Commercial Group.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to explain Real Time Pricing (RTP), its overall benefits, and how it can be used as an efficient pricing mechanism for large commercial customers. It is my belief that, when designed correctly, an RTP tariff can benefit the utility, participants, and even non-participants.

Q. WERE YOU THE ORIGINAL WITNESS FOR GEORGIA POWER COMPANY'S REQUEST FOR TARIFF APPROVAL OF REAL TIME PRICING?

A. Yes, along with Jon Kubler.

Q. DO YOU HAVE ANY EXHIBITS?

A. Yes, CG Exhibit No. ___ (MTO-1) reveals RTP price responses of various commercial customers.

Q. WHAT EXACTLY IS REAL TIME PRICING?

A. Real Time Pricing (RTP) is an electricity rate structure in which retail energy prices change very frequently, usually hourly, and with short notice, usually day-ahead. These hourly prices are designed to reflect the supplier's expected hourly marginal cost of providing incremental load. These hourly cost can also reflect market costs. RTP is the most efficient means to price electricity to retail customers.

Q. WHAT DO YOU MEAN BY EFFICIENT?

A. RTP does the best job of signaling to retail users what is the utility's actual marginal cost of providing incremental load. It enables the customer to make an efficient usage decision based upon the true cost of providing energy. RTP also recognizes and allows for the fact that energy value is specific to each user and dynamic. Additionally, large system benefits can be achieved by offering RTP to customers. A few customers on RTP can provide large benefits to the utility and the entire system as RTP price response becomes a system resource. RTP will inherently reorder customers into cooperative teammates producing win-win solutions. One participant voluntarily forgoes consumption while another eagerly consumes a kWh.

Q. CAN YOU ELABORATE ON THESE BENEFITS OF RTP?

A. Through RTP price response, the overall system reliability can be improved. Retail consumers can now back-off usage when wholesale prices are high ultimately providing a dampening effect upon a run-up in wholesale prices. The utility will become less dependent upon outside power purchases. RTP customers are often able to lower their cost of energy but in a manner that is beneficial to the utility. Customer satisfaction of RTP participants improves. Participants have an incentive to innovate with economic energy efficiency programs and devices. RTP should, in the long run, be the least expensive pricing product that a utility can offer.

Q. WHY SHOULD RTP BE LESS COSTLY THAN A STANDARD EMBEDDED TARIFF?

A. Electricity is the most volatile publicly traded commodity in the world. Hourly unit cost can change by a multiple of 100 within a 24-hour period. This volatility is driven in large part by electricity's unique characteristics:

1) It cannot be stored to any great degree. It must be produced when demanded.
2) It is not easily transported over great distances.
3) Most customers expect the product to be available whenever requested. A busy signal is unacceptable; in fact, the physics of the product would not permit it.
4) It is ubiquitous. It is woven into the fabric of nearly every aspect of our lives.

Most customers cannot accept the hourly cost risk of electricity. Therefore, utilities have historically absorbed this cost risk themselves and have offered relatively stable rates with inherent premiums. If, however, this cost risk can be passed along to customers who are willing to absorb it, the corresponding price offered to these customers can be less.

This is what Real Time Pricing (RTP) is all about: transferring the underlying cost risk onto a willing customer at what is normally an otherwise cheaper rate on an expected basis. I mentioned normally because there can be certain times whereby the RTP prices average more than traditional tariffs, in which the utility absorbs the risk. But, over the course of time, RTP should be cheaper.

RTP is not a traditional tariff. It does not signal to customers the cost of electricity based upon embedded revenue requirements. It bases the price signal upon marginal cost so that the customer can make a "real-time" decision as to whether his value of using a kWh is greater than the actual "real-time" cost of a kWh. More efficient consumption decisions are therefore made than had the price signal been based upon embedded, and therefore fixed cost.

However, the utility has also incurred costs in the past that are not reflected in RTP prices. Examples of these costs include overheads, certain distribution costs and regulatory assets. These costs, too, must be compensated with commensurate revenue. With traditional tariffs, these cost components are rolled into the bundled prices. But with a two-part RTP tariff, they are collected through a "standard bill" based upon a customer baseline load (CBL) and a traditional tariff.

The RTP tariff contains two parts. The first part uses a CBL to collect fixed costs and the second part, with changes in usage subject to incremental RTP prices, covers the cost of marginal load.

Q. CAN YOU EXPAND ON A CBL AND ITS PURPOSE.

A. A CBL is a customer specific hourly load responsibility that is used along with the utility's standard embedded tariff for the customer in order to develop the "standard bill" portion for the RTP customer. This standard bill is the first part of the customer's two-part RTP bill.

Q. PLEASE ELABORATE ON THE PURPOSE OF THE "STANDARD BILL."

A. Its meaning can be explained by the Georgia Public Service Commission's Letter Order in Docket No. 4147-U approving RTP-DA-1 as a permanent tariff. It states:

> In addition to the hourly energy charges, each RTP customer will pay a customer-specific standard bill based on that customer's previous rates and load pattern. The standard bill based on that customer's previous rates and load pattern. The standard is designed such that the customer's total bill under Rate Schedule RTP-DA-1 would approximate its bill under the Company's conventional tariffs if the customer did not change its pattern of electricity usage. The standard bill is based on the customer's previous rates and load pattern. It is designed so that the customer's bill under Rate Schedule RTP-DA-I would approximate his bill under the Company's conventional firm tariffs if he did not change his pattern of electricity usage. The standard bill component minimizes the potential for revenue erosion. The hourly energy prices reflect the Company's marginal cost of producing and delivering electric power during a given hour.

So, as you can see, the standard bill enables RTP customers to be revenue neutral for this CBL load whether they are on RTP or a standard tariff. It enables the utility to recover its fixed cost, which the standard tariff is designed to cover. The standard bill also provides the customer with price assurance for its CBL load since it is priced through a standard tariff.

Q. HOW IS THE CBL DEVELOPED?

A. A CBL for a given customer is based on their previous year's electric usage, divided into hourly increments.

Q. SHOULD A CBL EVER CHANGE?

A. With rare exceptions, the answer is no. In general, once a customer's CBL is established, it does not change over time. The only possible exception is in cases where there is a permanent and documented change in a customer's operation, such as addition of conservation features. Changes to a customer's CBL should be mutually agreed upon by the customer and the Company.

Q. LET'S RETURN TO THE ISSUE OF SETTING A CBL. IN THE ABSENCE OF LOAD HISTORY, FOR INSTANCE, IN THE CASE OF A NEW CUSTOMER, WHAT IS THE PHILOSOPHY FOR SETTING A CBL?

A. In order to deal with new customers with no load history, a technique for establishing the amount of fixed cost responsibility for these customers must be developed. There are many different ways in which this could be done, including: a) requiring the new customer to demonstrate his firm load requirement; b) trying to simulate a load level; c) negotiations between utility and customer; d) requiring that the new customer wait a year before going on RTP; and e) a certain agreed to percentage. The desired technique needs to be administratively simple and workable for both the utility and the customer. It should be reasonable and logical.

Q. IF AN EXISTING CUSTOMER IS CONSIDERED TO BE REVENUE NEUTRAL FOR THEIR HISTORICAL LOAD (I.E. – CBL) AND THE TRADITIONAL TARIFF BILL AMOUNT, IS A NEW CUSTOMER "REVENUE NEUTRAL"?

A. Since there is, by definition, no history for a new customer, there is nothing with which to be revenue neutral.

Q. IF AN EXISTING CUSTOMER MIGRATES TO RTP WITH A HIGH CBL, CAN HE DERIVE ANY BENEFIT FROM BEING ON RTP?

A. This type of customer could realize substantial benefits through price responding. Price responding below the CBL during hours of high RTP prices will result in credits which will lower his overall cents/kWh. Early in the RTP program, this feature became clear to many customers who then migrated to RTP. For example, imagine a year in which RTP prices averaged 3 cents/kWh for 8660 hours and 30 cents/kWh for 100 hours. Also, imagine a customer with a 100 percent CBL at a price of 4 cents/kWh. For a constant strip of CBL load, by price responding during the 30 cents/kWh hours, the customer's overall cents/kWh would be reduced from 4 cents/kWh to a little less than 3.7 cents/kWh, a drop of nearly 9 percent.

Q. IS RTP DESIGNED TO "FAVOR" CERTAIN CUSTOMERS WITH DISCOUNTED RATES?

A. No. The purpose of RTP is to expose customers willing to take on price risk to the utility's marginal cost and enable the customers to make efficient energy usage decisions. The premise behind RTP is that customer and Company resources will be used more efficiently if the price charged to customers reflects the marginal costs of serving them in each hour. This premise has been validated by the results of other utilities. Results have indicated that under real time pricing, customers will often reduce their usage in high cost, on-peak hours and increase usage in low cost, off-peak hours. Regardless of how their usage pattern changes, however, such customers will pay for incremental usage at a rate that closely reflects the utility's cost of producing or purchasing that electricity. Similarly, any reductions in usage by those customers below their normal load patterns will reduce their bills by amounts that reflect the saving in cost to the utility.

The standard bill based upon the CBL would collect the utility's fixed cost obligations from the RTP customer, thereby preventing the utility from having to recover these costs through other customers . So, by covering his fixed cost obligations and paying his marginal cost responsibility for his marginal load, the RTP customer covers all of his cost, thereby benefiting all. This overall benefit includes existing RTP and non-RTP customers by keeping revenue requirements down.

Q. CAN LARGE COMMERCIAL CUSTOMERS BENEFIT FROM RTP?

A. Yes, in a couple of ways. First, they can grow their business in low-price, off-peak times at lower energy prices than they could traditionally do under standard, embedded rates. Secondly they can lower usage during high price periods or shift it to off-peak periods. The two-part RTP tariff will lower the cost of energy as the commercial customer makes the changes in usage and will do so in a manner that helps, not harms, the utility. For example if the utility's marginal cost of providing the next kWh is 75 cents/kWh, the standard embedded rate might merely send a price signal of 10 cents/kWh but RTP will signal 75 cents/kWh. If the RTP commercial customer's value of electricity is 50 cents/kWh, they will curtail or shift usage into a lower price period when the RTP price is less than their value of energy.

Q. DO LARGE COMMERCIAL CUSTOMERS REALLY CURTAIL OR SHIFT USAGE?

A. Yes, many do so. The key is to provide them an incentive to do so. Two-part RTP is that incentive. Given an economic incentive, many customers who previously considered themselves to be inflexible with their energy usage will now devise various ways to price respond. These include lighting changes and retrofits, pre-cooling, use of back-up generation, enhanced air handling including use of fans, and many others. I've provided in my exhibit MTO-2 displays of how various commercial accounts have price responded. Some are big responders, some are not. But, regardless of whether they price respond or not, because they're paying the utility's marginal cost of providing energy, the utility is not only indifferent to the RTP commercial customer's usage decision but actually better-off.

Q. HOW IS THE RTP PROGRAM PROCEEDING AT GEORGIA POWER COMPANY?

A. It continues as the most successful program in the nation. There are over 1600 RTP customers of which over ½ are commercial accounts. RTP price response is included as a part of Georgia Power's Integrated Resource Plan enabling price response to supplant generating units and purchase power. Very few customers who have ever volunteered for RTP in Georgia have ever left the program.

A. WHY HASN'T RTP BEEN MORE WIDESPREAD IN USE?

Q. There are several reasons, I believe, and I've written an article mentioned in exhibit MTO-1 which goes into more detail. Bottom line though, I believe the major reasons are: 1) a problem with the original design of many RTP tariffs, 2) absence of additional products enabling the RTP customer to manage their price risk, 3) the timing of a utility's embedded cost versus their marginal cost, 4) a tendency to remain with traditional embedded tariffs rather than innovate with RTP, and 5) a reluctance to incur the administrative set-up costs of RTP. Obviously I feel that all of these obstacles are surmountable and inconsequential when one considers the enormous overall benefits of RTP.

Q. CAN YOU SUMMARIZE YOUR TESTIMONY?

A. Many large commercial customers possess on-site usage flexibility and can obtain flexibility which they are willing to employ if provided the right pricing signal from their utility. Large commercial customers can and will respond to RTP price signals. RTP is an efficient pricing methodology and should be offered in every utility's pricing portfolio for large business customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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ATTACHMENT A

Michael (Mike) T. O'Sheasy
Vice President, Retail Pricing and Solutions
Laurits R. Christensen Associates, Inc.

Mike O'Sheasy is a Vice President of Christensen Associates of Madison, Wisconsin. He retired from Georgia Power Company, an operating company in the Southern Company system, as the Manager of Product Design. His responsibilities include pricing strategy development and future rate planning; rate research, design, and evaluation; and the preparation and filing of retail rates.

Mike was the architect of the Real Time Pricing program at Georgia Power which is the largest program in the United States. Other leading edge innovation championed by Mike include: Flat Bill, Price Protection Products, Multiple Load Management, Interruptible Exchange Service, Multiple Account Management, and Daily Energy Credits. He has consulted with many utilities including Public Service of Oklahoma, Duke Power Company, Salt River Project, Kansas City Power & Light, PP&L, Ohio Edison, Illinois Power, Wisconsin Electric Power Company, South Carolina Electric and Gas and others on pricing issues.

Mike joined Southern Company Services in 1980 as an engineering cost analyst and progressed throughout various positions in the Marketing and Regulatory Support Department, specializing in allocated cost of service studies. While at SCS, he was selected for the Southern's Superlative Award. He has testified before various Commissions as an expert witness on both costing and pricing. Mike has received industry awards, including EPRI Innovator Awards and the Product Champion Award. He has published numerous articles on pricing in national magazines including the *TAPPI Journal, Public Utilities Fortnightly, Electric Perspectives, EPRI Journal, Energy Pulse, Energy Customer Management,* and the *Electricity Journal.* He has a national reputation for pricing innovation and has been interviewed in *USA Today,* the front page of the *Wall Street Journal, Newsweek,* National Public Radio and CNN FN. His reputation internationally has earned him consulting projects on four continents.

Professional Papers:

"Is Real-Time Pricing a Panacea? If So, Why Isn't It More Widespread?" *The Electricity Journal*, December 2002.

"Flat Prices for Peak Hedging," *Public Utilities Fortnightly*, November 1, 2002.

"RTP Customer Demand Response – Empirical Evidence on How Much Can You Expect," in *Electricity Pricing in the Transition* A. Faruqui and K. Eakin, eds., Kluwer Academic Publishers, 2002 (with Michael O'Sheasy).

"Flat Bills, Peak Satisfaction," Energy Customer Management, January/February, 2002.

"The New Pricing Organization," EPRI International Pricing Conference, co-authored with Robert Camfield, 2000.

"Roll the Dice, Set a Price," *Public Utilities Fortnightly*, May 15, 1999.

"5-cent Sundays…The Future of Electricity Prices?" *Electric Perspectives*, January/February 1999.

"Real-Time Pricing – Supplanted by Price-Risk Derivatives," *Public Utilities Fortnightly*, March 1, 1997.

"Customers Can Buy Low, Sell High," *The Electricity Journal*, February 1998.

"Real-Time Pricing for Purchased Electricity: An Innovative Pricing Option for Electricity as Used by the Pulp and Paper Industry", TAPPI Journal, April 1996.

"Reaping the Benefits of RTP: Georgia Power's RTP Evaluation Case Study," Volumes 1 and 2, Electric Power Research Institute (EPRI), December 1995.

Q. Please state your names and positions.

A. My name is Mike Culver. I am the Senior Project Manager – Energy for J.C. Penney Corporation, Inc. ("JC Penney"). My name is Charlie Martin. I am the Energy Manager for Lowe's Companies, Inc. ("Lowe's"). We are testifying on behalf of the Commercial Group that is composed of BJ's Wholesale Club, Inc., Lowe's, JC Penney, and Wal-Mart Stores East, L.P.

Q. Have you provided outlines of your background and professional experience?

A. Yes, these are attached as Appendix A hereto.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. We are sponsoring one exhibit, CG Exhibit No. __ (CM-1), which is a portion (electric providers in the Southeast) of the Edison Electric Institute's ("EEI's") Typical Bills and Average Rates Report for electric providers (Summer 2004-Winter 2005).

Q. Please describe generally your operations in the State of Florida.

A. Together our companies operate approximately 400 retail establishments in Florida, including a number of distribution centers. A substantial number of these facilities receive retail electric service from Progress Energy Florida, Inc. ("PEF"). We employ well over 100,000 employees at our Florida operations alone and purchase several billion dollars annually in goods and services from Florida suppliers. In a period in which industrial job creation may be slowing, large commercial facilities such as ours are one of the key drivers of the Florida economy. Indeed, our companies pay billions of dollars in annual salaries and benefits to our Florida employees and taxes into the state of Florida.

Q. Please describe your operations.

A. Our companies operate retail facilities across the country. These facilities receive electric service from hundreds of electric providers under varied rate schedules and are subject to varying degrees of regulation by state public service commissions.

Q. Please describe the purpose of your testimony and summarize your testimony.

A. Our panel is providing testimony on whether PEF deserves a 50 basis point ROE performance incentive adder for superior service, the impact PEF's proposed rate increase would have on our facilities and operations, and background for the testimony of our group's other witness, Mike O'Sheasy, concerning a Real-Time-Pricing ("RTP") rate proposal. In general, we find PEF's customer service to be adequate and comparable to that of other electric providers that serve our facilities. We find that PEF's rates, however, are substantially higher than those of our other electric providers, and that PEF's rate schedules could be better tailored to our facilities. Accordingly, we are proposing an addition to PEF's rate offerings. With respect to how the proposed rate increase would affect our facilities, the potential cost impact would indeed be great.

Q. Do you believe that PEF should receive an extra return on investment as a reward for superior service?

A. No. As mentioned above, our facilities are served by hundreds of electric service providers across the country. In our experience, PEF provides average to good electric service and we generally have a positive relationship with PEF. However, we do not find PEF's service to be superior to that of most other comparable electric service providers. One important way that we judge service is by comparing the rates the service provider charges. With respect to electric bills that we receive from PEF, the Company's commercial rates are substantially higher than those of many similar electric utilities. In fact, as shown by CG Exhibit No. __ (CM-1), PEF's commercial rates are higher than those of any other electric provider in the Southeast that is listed by EEI. Dr. Cicchetti cites Georgia Power Company in his testimony (p. 44) concerning the ROE adder. Georgia Power, is another significantly sized electric utility in the Southeast. We note by way of example that Georgia Power Company recently received a substantial ($500 million) fuel rate increase. Nevertheless, even after that increase, the fuel rates that PEF charges us are much higher than those of Georgia Power (2.42¢/kWh). Similarly, the exhibit CM-1 shows the commercial rates of Georgia Power overall to be significantly lower than those of PEF. With PEF requesting a further rate increase, PEF will be even less competitive as far as rates are concerned. Accordingly, with PEF's rates already being comparatively high, we do not believe those rates should be raised further to reward PEF for what PEF argues is superior service.

Q. Please describe your evaluation of PEF's customer service.

A. We have found that PEF's customer service is adequate to good and we appreciate that service. Nevertheless, we cannot say that the customer service of PEF is superior to that of most other electric providers of its size.

Q. You mentioned a concern with PEF's rate options. Please describe your concern.

A. A number of electric providers offer rate schedules that fit our facility load profiles and that enable large commercial customers like our companies to capture benefits from our substantial in-house energy management efforts, as well as the energy efficiencies that we build into our facilities. Since Dr. Cicchetti mentioned it, Georgia Power Company is one such example in that it provides a very successful Real Time Pricing ("RTP") tariff that is very popular with its commercial and industrial customers. Our consultant, Mr. O'Sheasy, presents a similar RTP proposal for PEF in his testimony.

Q. Has PEF proposed any new rate schedules in this proceeding that might better fit the load profiles of your facilities?

A. No, it has not. We hope therefore that PEF will consider carefully Mr. O'Sheasy's rate design proposal.

Q. Are there any other rate design alternatives that you would like PEF to consider?

A. Yes. In order to make the time of use rates more useful to commercial customers, PEF should reduce the length of the on-peak hours, which length currently lasts up to nine hours, and provide more opportunity for higher load factor customers to capture a portion of the benefits that the PEF system receives from the higher load factor usage pattern. We have a number of other suggestions that we would be glad to discuss with PEF.

Q. Please briefly describe some of the ways your companies design energy efficiencies into your facilities.

A. Our companies have centralized energy management systems in place to control energy usage at our individual facilities. We design our facilities to be energy efficient by incorporating technological advances into our facilities. Such advances include (among other things) high efficiency lighting and HVAC units, daylighting controls that allow us to use daylight instead of artificial light, and parking lot lighting photo cell controls.

Q. You mentioned that you are concerned with the rate increase that PEF has proposed. How would the proposed increase affect your operations?

A. As we mentioned above, PEF's commercial rates are already significantly higher than those of many other electric providers and, according to the EEI data, may be the highest of any similar electric utility in the Southeast. In this case, PEF is proposing to increase commercial rates even further with GS-2, GSD, CS, IS and the SS rates to rise by a whopping 20 percent! Energy costs are the second highest operating costs at our facilities and such a large increase in rates will greatly impact our operations. For operations such as distribution centers that can locate in other states or service territories, utility costs are a significant factor toward our choosing a non-PEF location. We urge the Commission to take a hard look at the proposed rate increase and act to minimize rate shock to any customer group.

Q. Do you have any observation on Mr. Slusser's class cost of service analysis?

A. Yes. We have not performed any detailed alternative cost of service study. However, even a cursory review shows that something appears to be wrong with Mr. Slusser's analysis.

Q. Please explain.

A. Our experience has been that cost studies performed by other electric utilities typically show commercial customers are paying more than their share of system costs (above parity) even though commercial rates typically are lower than residential rates. However, as shown by EEI in the attached exhibit CG-1, PEF's commercial rates are comparable to its residential rates – yet Mr. Slusser alleges that PEF's commercial classes are substantially below parity. Therefore even at a general level, something appears to be wrong with Mr. Slusser's analysis.

Q. Does this complete your testimony?

A. Yes, it does.

Professional Profile – Mike Culver

BUSINESS ADDRESS
JC Penney Company, Inc., 6501 Legacy Drive, MS: 2112, Plano, Texas 75024.

POSITION
Senior Project Manager – Energy. My responsibilities include the development and management of energy strategies for the company. I am also responsible for the procurement of electricity and natural gas, energy reporting, bill payment, investigating and testing new technologies, and capital investment in the energy infrastructure.

EDUCATION AND EXPERIENCE
I received a B.S. in Electrical Engineering from Texas A&M University in 1990 and am a Registered Professional Engineer in Texas. For twelve years, I was employed by Xcel Energy in a variety of positions, including (in chronological order) Division Engineer, District Engineer, Sales Account Representative, and Account Executive – Commodity Sales. I have been employed by JC Penney for the past two years as Senior Project Manager – Energy.

PREVIOUS TESTIMONY
I have previously testified before the California Public Utilities Commission in:

Application of Pacific Gas and Electric Company for Authority to Implement Default CPP RateOptions for Large Customers, Application 05-01-016, (Filed January 20, 2005)
____)

Application of San Diego Gas & Electric Company (U902-E) for Adoption of a 2005 Default Critical Peak Pricing Structure for Commercial and Industrial Customers with Peak Demands Exceeding 300 kW., Application 05-01-017, (Filed January 20, 2005)
____)

Southern California Edison Company's (U338-E) Application for Approval of Rate Design Proposals for Large Customers., Application -05-01-018, (Filed January 20, 2005)
____)

ATTACHMENT A

Professional Profile - Charles A. Martin, P.E., C.E.M.

Over 27years of experience in the field of energy management and energy engineering.

EMPLOYMENT

Energy Manager, Lowe's Companies, Inc. **2002-Present**

- Manage utilities payment for Fortune 60 company, including electricity, natural gas, water and sewer for retail, distribution, and corporate facilities
- Responsible for utility budgeting for retail properties
- Directs Lowe's energy procurement regarding electricity and natural gas for all facilities
- Facilitates technical assessment of energy efficiency and sustainability
- Conducts studies and facilitate implementation of energy conservation measures, demand control, and operating cost reduction strategies

Chief Consultant – Energy Services, The Foresight Group, Raleigh, NC **2000 – 2002**

- Conducted engineering, project development and supply side studies for industrial facilities, Class-A office buildings, education and health care facilities resulting in cooling, ventilation, lighting system improvements, process optimization and distributed generation projects
- Developed and implemented an energy utilization model for Lowe's Home Improvement
- Developed and delivered energy auditor training for Duke Energy
- Developed industrial and commercial energy utilization tools and training for Progress Energy

Carolina Power and Light Company (CP&L), Raleigh, NC **1995 - 2000**

- Supervised the day-to-day activities of the Facilities Energy Services Team (10 engineers and analyst positions)
- Served as primary interface with marketing, preparing cost estimates for engineering studies, scheduling and assigning work
- Reviewed engineering documents including preliminary survey reports, detailed survey reports, as-built drawings, and commissioning reports
- Provided direct engineering support in delivering Asset Management and Energy Partnership products

EDUCATION **Virginia Polytechnic Institute and State University (VPI),** Blacksburg, VA
Bachelor of Science, Mechanical Engineering

RECOGNITIONS

- Registered Professional Engineer (North Carolina & South Carolina)
- Certified Energy Manager
- ASHRAE Regional Award of Merit – 1998
- ASHRAE Regional Officer of the Year - 1997
- Key Performer Award – BEST (Building Energy Simulation Tools)
- Volume X - Energy Code for North Carolina, Adhoc Energy Committee, NC Department of Insurance – 1991 to 1996

ORGANIZATIONS

- Association of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE)

DIRECT TESTIMONY OF THOMAS E. STAMBAUGH

Q. Please state your name and business address.

A. My name is Thomas E. Stambaugh and my business address is 4950 West Kennedy Boulevard, Suite 310, Tampa, Florida, 33609.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst IV in the Division of Auditing and Safety.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since November 1984.

Q. Please briefly review your educational and professional background.

A. In 1965, I received a degree in Business Administration with a major in Industrial Management from Southern Methodist University. In 1976, I received a Degree in Accounting from the University of South Florida. I performed industrial accounting work until 1981, when I was hired by the Florida Department of Health and Rehabilitative Services (HRS) as an accountant. After three years with HRS, I began working for the Florida Public Service Commission (Commission). I attained the Certified Internal Auditor designation in 1989.

Q. Please describe your current responsibilities.

A. Currently, I am a Regulatory Analyst IV with the responsibilities of planning and directing the more complicated financial, program, special and investigative audits, including audits of affiliate transactions. I also am responsible for creating audit work programs to meet a specific audit purpose and integrating electronic data processing (EDP) applications into these programs.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I testified in the Jasmine Lakes Utilities rate case, Docket No. 920148-S, and the Aloha Utilities, Inc. rate case, Docket No. 991643-SU.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Progress Energy Florida (PEF or utility), Docket No. 050078-EI. The audit report is filed with my testimony and is identified as TES-1.

Q. Was this audit report prepared by you?

A. Yes, I was the audit manager in charge of this audit.

Q. Please review the work you and the audit staff performed in this audit.

A. For rate base, we compiled plant in service, accumulated depreciation and working capital accounts for 2004, and reconciled these to the Minimum Filing Requirements (MFRs). We also verified plant additions and retirements. For net operating income (NOI), we compiled NOI accounts and reconciled these to the MFRs. We also calculated the rate of return, and verified the amounts of revenue and expense which were removed from NOI for Fuel Adjustment, Capacity Cost Recovery, Energy Conservation Cost Recovery, and Environmental Cost Recovery Clauses. We compiled revenue and reconciled it to the MFRs and recomputed revenues using Commission approved rates and company provided KWH sales. We also reconciled the utility "revenue recap" report to the general ledger on a test basis and tested customer bills on a spot-check basis. We analyzed a shared-revenue refund prescribed by Commission Order PSC-02-0655-AS-EI, and the Allowance for Doubtful Accounts. We compiled Operating And Maintenance (O&M) Expenses and reconciled them to the MFRs. We also tested O&M expenses by tracing to vendor invoices. We traced the MFR income tax amounts to the general ledger and recomputed taxable income and income tax. We verified that sales tax discounts (collection and remitting expense) were stated "above the line" and reviewed property taxes and regulatory assessment fees.

Q. Please review the audit disclosures in the audit report.

A. Audit Disclosure No. 1 discusses Accretion Expense. In its MFR Schedule C-6, page 6 of 7, PEF states 2004 actual Accretion Expense to be $17,369,000. Accretion Expense is designed to be offset by the amounts in general ledger accounts 4031001, Nuclear Decommissioning Expense, and 4073002, Nuclear Decommissioning Regulatory Liability Amortization. At the end of 2004, the three accounts carried a balance of $184,933. Because this balance should be zero, I recommend that O&M expense for 2004 should be reduced by $184,933. The general ledger account 4110101 should be adjusted by ($184,933) to correct the expense amount.

Audit Disclosure No. 2 discusses Taxes Other than Income. PEF incurred $2,285,510 in Regulatory Assessment Fees (RAFs) during 2004. The general ledger reflected $2,278,632 for RAFs in general ledger account 408113J, for a difference of $6,878. For the Historical Base Year 2004, the MFRs recorded $2,279 (rounded in thousands). In addition, PEF incurred $77,016,181 for Gross Receipts Tax during 2004.

The general ledger reflected $76,898,361 in general ledger account 408125J, for a difference of $117,820. For the Historical Base Year 2004, the MFRs recorded $76,898 (rounded in thousands). I recommend that Taxes Other Than Income are understated by $124,698 ($6,898 + $117,820) in Historical Base Year 2004.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF CARL S. VINSON, JR. AND WILLIAM "TRIPP" COSTON

Q. Please state your name and business address.

A. (MR. VINSON): My name is Carl Vinson, Jr. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida.

(MR. COSTON): My name is William "Tripp" Coston. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida.

Q. By whom are you employed and in what capacity?

A. (MR. VINSON): I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utilities Supervisor within the Bureau of Regulatory Review, Division of Competitive Markets and Enforcement.

(MR. COSTON): I am employed by the Florida Public Service Commission (FPSC or Commission) as a Government Analyst I within the Bureau of Regulatory Review, Division of Competitive Markets and Enforcement.

Q. What are your duties and responsibilities?

A. (MR. VINSON): As a Public Utilities Supervisor, I oversee four analysts. They conduct operations reviews and complaint investigations of regulated Florida utilities, and also participate in docketed proceedings. One of these analysts is Mr. Coston, who is testifying jointly with me.

(MR. COSTON): As a Government Analyst I, I conduct operations reviews and complaint investigations of regulated public utilities.

Q. Please describe your educational background and professional experience.

A. (MR. VINSON): I received a Bachelor of Business Administration degree in Finance from Stetson University in 1980. I have worked for the Commission for 15 years conducting and supervising operations audits and investigations of regulated electric, telephone, gas, and water companies. Prior to my employment with the Commission, I worked for five years as a Research Associate with the consulting firm of Ben Johnson and Associates, Inc., in Tallahassee, Florida. Dr. Johnson's firm participates in utility proceedings throughout the country.

(MR. COSTON): I received Bachelor of Arts and Master of Public Administration degrees from Valdosta State University in 1993 and 1995, respectively. I have worked for the Commission for two years conducting operations audits and investigations of regulated electric and telephone companies. Prior to my employment with the Commission, I worked for six years as a Treasury Services Officer with Bank of America in Atlanta, Georgia.

Q. Have you previously testified before this or any other utility commission?

A. (MR. VINSON): I have prefiled direct testimony before this Commission in two dockets regarding audits of a telecommunications company. In both cases, the dockets were settled prior to hearing.

(MR. COSTON): No, I have not.

Q. What is the purpose of your direct testimony?

A. The purpose of this direct testimony is to present the results of the review we conducted regarding Progress Energy's efforts in the areas of vegetation management, lightning protection, and pole inspection for the period 1999 through 2004. This review was requested by the Division of Economic Regulation to examine Progress Energy's efforts and activities for protecting its system and customers from outages caused by vegetation, lightning and pole failure.

Q. Do you have any exhibits to your testimony?

A. Yes, Exhibit No. CV/TC-1 is the report on our operations audit of Progress Energy Florida, entitled *Preliminary Review of Vegetation Management, Lightning Protection, and Pole Inspection at Progress Energy Florida, Incorporated.*

Q. Please summarize your testimony.

A. Based on the focused review of Progress Energy's functional areas of vegetation management, lightning protection and pole inspections, we have made the following observations: Progress Energy has experienced an increase in vegetation-caused interruptions during the 1999 through 2004 review period. Along with the increase in outages, the number of customer interruptions due to vegetation-related outages has increased. The number of feeder miles trimmed by the company generally trended downward during the 1999 through 2004 review period.

Progress Energy's number of distribution lightning interruptions and average outage minutes generally declined during the review period. No deficiencies regarding lightning protection efforts and activities were noted in our review.

Progress Energy experienced few outages due to distribution pole failure relative to other causes, with seven or fewer such outages during each year of the review period. While the company has conducted pole inspections during the review period, staff notes the company has not maintained its inspection schedule as outlined by management.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF SIDNEY W. MATLOCK

Q. Please state your name and business address.

A. My name is Sidney W. Matlock. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399-0850.

Q. By whom are you employed and in what capacity?

A. I am employed by the Florida Public Service Commission (Commission) as a Regulatory Analyst in the Division of Economic Regulation.

Q. What are your present responsibilities with the Commission?

A. My responsibilities include analysis of utility regulatory filings in the Fuel Cost Recovery docket and other dockets and activities relating to electric distribution reliability and electric meter accuracy.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from the Florida State University in August of 1975 with a B.S. degree in economics. I was employed by the Florida Department of Commerce (later the Department of Labor and Employment Security) from February of 1976 to February of 1985. I have been employed by the Florida Public Service Commission since February of 1985. In August of 1992, I obtained a B.S. degree in statistics from the Florida State University.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Docket Number 030623-EI, <u>Complaints by Ocean Properties, Ltd., J.C. Penney Corp., Target Stores, Inc., and Dillard's Department Stores, Inc. against Florida Power & Light Company concerning thermal demand meter error</u>. I have also filed testimony in Docket Number 050045-EI, <u>Petition for rate increase by Florida Power & Light Company</u>, the hearing for which is scheduled to begin August 22, 2005.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring Exhibit SWM-1, consisting of one table containing three columns of reliability index data and three line graphs, one for each column.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the values of three distribution reliability indexes - System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and System Average Interruption Frequency Index (SAIFI) - for the years 1992 through 2004 for Progress Energy Florida, Inc. (PEF).

Q. Please define each index.

A. SAIDI is the average number of customer minutes of interruption per customer, for the utility system. It is the total customer minutes of interruption divided by the total number of customers served.

CAIDI is the average number of customer minutes of interruption per customer interruption. It is the total customer minutes of interruption divided by the total number of customer interruptions.

SAIFI is the average number of customer interruptions per customer, for the utility system. It is the total customer interruptions divided by the total number of customers served.

Q. What is the importance of these data?

A. These indexes are used as indicators of utility performance in the area of distribution reliability. Changes in the indexes over time are interpreted as indicators that the utility is performing better or worse, depending on the direction of change, than in an earlier period.

These data for 2001 and 2004 and their changes over the three-year period appear in direct testimony of Dale Oliver in Docket Number 050078-EI to support the effectiveness of PEF's Commitment to Excellence (CTE) program. Direct testimony of Jeff Lyash discusses the values of SAIDI in 2000 and 2004 in connection with the settlement order from the 2002 rate case. Direct testimony of Dr. Charles J. Cicchetti also lists the values of SAIDI in 2000 and 2004 as part of PEF's request that 50 basis points be added to PEF's return on equity for superior performance.

The company witnesses show some of these data for the last four years. My testimony shows the data for the last thirteen years. Therefore, with the additional nine years of data provided in my testimony, one may approximate changes in performance since 1992, and see the recent changes in a clearer context. The three indexes are presented in Exhibit SWM-1.

Q. What are the sources of the reliability indicators you are using in your analysis?

A. The 1992 through 1999 data are taken from the Commission report titled "Review of Electric Service Quality and Reliability at Florida Power Corporation and Florida Power & Light Company", published in November 2000. The data were obtained by making document requests of the company in 2000. The 1998 through 2004 data are taken from the Annual Distribution Service Reliability Reports filed by PEF. There is an overlap for 1998 and 1999.

Q. How do the 2001 through 2004 changes presented by PEF witnesses compare to the changes from 1992 through 2004?

A. Judging strictly by the index changes between the first (1992 or 2001) and last (2004) years, PEF improved its performance over both periods, but the changes over the earlier nine years (1992 through 2001) were not smooth and gradual. Each of the three indexes dropped sharply in 1993. However, the improvements shown in 1993 were nearly offset in each of the following two or three years, as performance declined significantly during those years. CAIDI peaked in 1995, and the two system indexes, SAIDI and SAIFI, peaked in 1996. From those peak levels, improvements were made somewhat more steadily through 2004.

The levels of the indexes in 2001 were roughly the same as in 1992. Further, most of the improvement in the 2001 through 2004 period occurred in 2004. The improvements in distribution reliability indicated by the 2001 through 2004 indexes, even considering comparable improvements over the earlier period, should not be the basis for assessing the current level of PEF's performance.

Q. Based on your analysis of PEF's 1992 through 2004 reliability data, should the Commission reward PEF's improved performance since 2000 or 2001 by adding 50 basis points to its return on equity?

A. No. Even though improvements were made in the years 2002 through 2004, examination of the data in Exhibit SWM-1 reveals three things regarding the 2004 levels of SAIDI, CAIDI and SAIFI:

(1) Greater improvements were achieved over earlier periods than over the years 2001 through 2004;

(2) The 2002 through 2004 improvements were a continuation of improvements that began in 1995 or 1996 following sharp declines in performance after 1993; and

(3) A comparison of the indexes of the two years 1992 and 1993 with those of the two years 2003 and 2004 shows that without the changes from 2003 to 2004, little overall improvement has taken place over the entire period.

Furthermore, PEF's 2004 SAIDI of 77.0 minutes does not constitute superior performance. The 2002 rate case settlement order stated that PEF would provide a $3 million refund to customers should it not achieve a 20% reduction in SAIDI, measuring from the 2000 index level, in 2004 and in 2005. The condition of the order has not been met. If the condition of maintaining SAIDI at or below 80.48 minutes in 2004 and 2005 is met, and the $3 million refund is avoided, that may serve as an indication that the improved performance is sustainable, but it would not constitute superior performance. Meeting this condition, viewed in the light of the three series of reliability indexes over the past thirteen years, would merely indicate that PEF's performance in the area of distribution reliability is adequate.

Q. Does this conclude your testimony?

A. Yes, it does.

REBUTTAL TESTIMONY OF

JEFF LYASH

I. Introduction and Purpose

Q. Please state your name.

A. My name is Jeff Lyash.

Q. Did you submit Direct Testimony in this case on April 29, 2005?

A. Yes.

Q. Have you reviewed the intervener testimony filed on behalf of the Florida Retail Federation ("FRF")?

A. Yes. My review focused on the testimony of FRF witness Sheree L. Brown, and particularly on her comments related to distribution and transmission spending.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to certain mischaracterizations made by Ms. Brown in her direct testimony regarding Progress Energy Florida, Inc.'s ("PEF's" or the "Company's") distribution and transmission spending.

Q. Do you have any exhibits to your testimony?

A. Yes. I have prepared or supervised the preparation of Exhibit No.____ (JL-1), an O&M benchmark analysis.

This exhibit is true and accurate.

II. Distribution and Transmission Spending

Q. Ms. Brown implies that PEF has engaged in a regulatory "sleight of hand" by overstating expenses in Docket No. 000824-EI (PEF's last rate case) and, in the intervening years, systematically controlling expenses below such levels to improve profits. Do you agree?

A. Absolutely not. As I will discuss in detail, Ms. Brown's contentions are not supported, and are, in fact, belied by PEF's performance, and by the factual record in this matter. Contrary to Ms. Brown's assertions, PEF takes its responsibility to all stakeholders seriously and constantly endeavors to balance its efforts for the mutual benefit of all key stakeholder groups, including customers, employees, and investors. I am very proud of our track record in this regard. My direct testimony, along with that of Bill Habermeyer, Dale Oliver and other company witnesses, describes in detail the significant improvements that we've made for customers and employees. At a high level, we've significantly improved our customers' reliability and service across a broad range of measures. For employees, we've focused on improvements in safety, our fleet and facilities, and culture. The data we've seen shows that both groups have noticed and appreciate the improvements. We've also taken our responsibility to investors seriously and have prudently managed the Company in an effort to produce reasonable returns and continued financial strength. Progress Energy's philosophy is that all stakeholders must be well served to create a strong utility and that a strong utility, in turn, benefits all stakeholders.

Q. Do you have any other comments on this matter?

A. Yes. I'd like to point out that Ms.Brown refers repeatedly to spending levels proposed in Docket No. 000824-EI, and specifically, to the Company's as-filed testimony and Minimum Filing Requirements ("MFR") schedules. She conveniently ignores, however, the fact that this as-filed rate case was superseded by a Stipulation and Settlement Agreement (the "2002 Settlement") entered into by the Company and interveners and approved by the Commission. That 2002 Settlement called for an annual revenue reduction of $125 million, almost $500 million over the term of the agreement. This is significantly different than PEF's as-filed rate case, which contained a $5 million annual revenue reduction and corresponding spending levels. In addition, the 2002 Settlement provided a revenue sharing mechanism that replaced the traditional ROE range and provided the potential for earnings upside. Because of this, a comparison of the Company's actual spending versus the *as-filed rate case proposal* is not valid. Further, Ms. Brown's underlying assumption that revenue could be reduced by nearly $500 million over the term of the 2002 Settlement without any change to the *as-filed* spending levels is not reasonable. Said in simple terms, Ms. Brown's contentions are based on an "apples to oranges" comparison and are not valid.

Q. Ms. Brown suggests that PEF has attempted to overstate its 2006 test year expenses in its filing so that the Company might inflate revenues and generate excess profits in years subsequent to this rate proceeding. Is this true?

A. Absolutely not. Our test year expense forecasts represent our best estimate of future expense levels. Our recent reorganization and mobile meter reading ("MMR") programs, initiated prior to this rate case, make it clear that PEF does not overstate expenses in rate case proceedings with the hopes of reducing those expenses in future years as Ms. Brown suggests. Were that the case, PEF, under Ms. Brown's theory, would have been motivated to withhold the implementation of initiatives such as reorganization and mobile meter reading until after PEF's rate case was completed.

Through PEF's reorganization, we have incorporated almost $20 million of O&M savings into our test year financial forecast. The Company will incur one-time costs in 2005 to implement the reorganization and these costs will be funded by shareholders. In addition, we've built almost $14 million in O&M savings into the test year forecast via MMR. Again, if the Company were truly following Ms. Brown's described strategy of inflating test year expenses and then cutting expenses subsequent to the rate case, we would have undertaken both of these initiatives after the conclusion of this proceeding. In fact, these examples make it self-evident that we do not conduct ourselves in the manner suggested by Ms. Brown and demonstrate our commitment to build a strong utility that benefits all stakeholders.

Q. Do you have any other comments regarding Ms. Brown's testimony on PEF's expense levels?

A. Yes. I would like to add that the Commission's benchmark comparison is designed specifically to test the reasonableness of test year expenses and here, it demonstrates that our proposal is reasonable. The FERC functional categories that roughly comprise PEF's Energy Delivery organization include Transmission, Distribution, Customer Accounts, Customer Service and Information, and Sales Expenses. As shown in my Exhibit No. ____ (JL-1), projected test year expenses for these areas, in total, are $25.1 million below the benchmark when adjusted for the effect of our change in accounting for outage and emergency costs. This is the case even with the inclusion of our proposed incremental transmission and distribution reliability initiatives. This means that our actual expenses from 2002, when adjusted for customer growth and inflation, would suggest a reasonable expense level $25.1 million, or 14%, higher than we have actually submitted. Ms. Brown's analysis is flawed, among other reasons, because she is making an invalid comparison to a rate case proposal that was superseded and never adopted by interveners, the Commission, or the Company.

Q. Does this conclude your testimony?

A. Yes.

REBUTTAL TESTIMONY OF
DALE OLIVER

I. Introduction and Purpose

Q. Please state your name.

A. My name is Dale Oliver.

Q. Did you submit Direct Testimony in this case on April 29, 2005?

A. Yes.

Q. Have you reviewed the intervenor testimony filed on behalf of the Florida Retail Federation ("FRF")?

A. Yes. My review focused on the testimony of FRF witness Sheree L. Brown, and particularly on her comments related to distribution, transmission, and the Commitment to Excellence ("CTE").

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to certain mischaracterizations by Ms. Brown testimony regarding Progress Energy Florida's ("PEF's" or the "Company's") distribution and transmission reliability spending and CTE through 2004 following the settlement of PEF's prior rate case.

II. Reliability Spending and CTE

Q. Ms. Brown argues that PEF overstated distribution and transmission reliability costs in Docket No. 000824-EI and has not, in fact, spent what it

represented to the Commission that it would spend over the past three years. Do you agree?

A. No. Ms. Brown is referring to testimony submitted by Robert Sipes and Sarah Rogers on November 15, 2001 in association with the Company's prior rate case. These spending recommendations, which represented a balanced outage mitigation and fault prevention program, were part of the Company's overall filing that called for a $5 million annual rate reduction for our customers. This filing proposal was superseded by a Stipulation and Settlement Agreement (the "2002 Settlement") entered into by the Company and intervenors, including Ms. Brown's client at that time, that was approved by the Commission.

Q. What is your understanding of the major terms of the 2002 Settlement?

A. The 2002 Settlement included benefits for both sides. For customers, the Company agreed to, among other things, reduce base rates by an annual amount of $125 million in revenues and to reduce System Average Interruption Duration Index ("SAIDI") by 20% or to 80 minutes by 2004 or refund customers up to $3 million. The 2002 Settlement also required the Company to share revenues with customers above a threshold amount. For the Company, the revenue sharing mechanism replaced the traditional ROE range and provided the Company the opportunity for higher earnings.

Q. Did the spending recommendations submitted by Mr. Sipes and Ms. Rogers in the last rate case carry over into the Company's subsequent commitments under the terms of the 2002 Settlement?

A. Clearly not. The programs identified in Mr. Sipes' and Ms. Rogers' testimony in Docket No. 000824-EI were based on an annual $5 million rate reduction and not on the annual $125 million rate reduction that PEF and the intervenors ultimately agreed to under the 2002 Settlement. The 2002 Settlement did not mandate the programs identified in Mr. Sipes' and Ms. Rogers' testimony and, beyond this, it is not reasonable to think the Company could reduce revenue by almost $500 million over the term of the 2002 Settlement with no change in underlying spending. Based on the 2002 Settlement, PEF necessarily re-prioritized programs to focus on outage mitigation measures. Within that context, which Ms. Brown fails to mention in her testimony, PEF nonetheless spent $123 million from 2002 to 2004 on key reliability initiatives over and above the normal, budgeted amounts. These initiatives are shown in Exhibit DO-1 to my direct testimony, and represent a very significant commitment to reliability and operational excellence. Ms. Brown's misstatement that the Company "overestimated" its distribution expenses in Docket No. 000824-EI is disingenuous and ignores the 2002 Settlement her client signed following the submittal of Mr. Sipes' and Ms. Rogers' initial testimony in that case.

Q. How did the Company develop the CTE program and set spending levels?

A. We developed our CTE program to, at a minimum, meet the commitments of our agreement and reduce SAIDI to 80 minutes by 2004. Beyond that, we designed the program to broadly improve the Company's operations and improve service to our customers. We prioritized initiatives with the potential to produce the greatest improvements. As a general rule, this guided us to prioritize outage mitigation programs, which proved to be highly effective in reducing the average duration of outages and in reducing the number of customers affected by those outages that did occur.

Q. Did you successfully complete CTE?

A. Yes. The Company achieved the goals outlined in its CTE program. As I explained in my direct testimony, PEF's 2000 distribution SAIDI of 100.6 minutes was reduced by 23% to 77 minutes by 2004, exceeding our commitment of a 20% reduction and 80 minutes. In the area of transmission, we reduced transmission SAIDI by 37% from 2002 to 2004. Beyond this, we also made improvements in several other reliability measures and in numerous other areas of our overall operations. The breadth and magnitude of our reliability improvement is highlighted in the Commission's most recent "Review of Florida's Investor-Owned Electric Utilities' Distribution Reliability" report. This most recent review of reliability covers the four-year period from 2000 through 2003 and shows that PEF demonstrated improvement on seven of eight reliability metrics examined. I am very proud of this success and believe that we have exceeded the obligations of our agreement. As I mentioned above, however, this is not to say that we completed all of the initiatives as outlined in the direct testimony of Mr. Sipes and Ms. Rogers in Docket No. 000824-EI. Many of those items, primarily those initiatives associated with fault prevention, have been carried forward and included in our current reliability proposal as described in the direct testimony of David McDonald and Ray DeSouza.

Q. Ms. Brown argues that incremental test year distribution reliability spending of $18.7 million proposed by Mr. McDonald in this docket should be reduced

by $10.038 million and incremental transmission reliability spending of $10 million proposed by Mr. DeSouza in this docket should be reduced by $2.189 million. Do you agree?

A. No. Ms. Brown recommends these reductions on the basis of a flawed principle. In essence, she calculates CTE spending as a percentage of the original, as-filed, reliability spending proposals in Docket No. 000824-EI and recommends that the Commission only approve the same proportion of this request. As I've described above, the 2002 Settlement renders the relationship between these two items absolutely meaningless. Since Ms. Brown's premise is flawed, it should not have any bearing on this proceeding.

Q. Does this conclude your testimony?

A. Yes.

REBUTTAL TESTIMONY OF

JOHN B. CRISP

I. Introduction and Purpose.

Q. Please state your name.

A. My name is John Benjamin Crisp.

Q. Did you submit Direct Testimony in this case on April 29, 2005?

A. Yes.

Q. Have you reviewed the intervenor testimony filed on behalf of the Office of Public Counsel ("OPC") and PCS Phosphate-White Springs ("White Springs")?

A. Yes. My review focused on the testimony of White Springs witness Maurice Brubaker, and OPC witness Donna Deronne. Particularly, I focused on Mr. Brubaker's comments regarding Progress Energy Florida's ("PEF") generation fleet, and Ms. Deronne's comments regarding the impact of the City of Winter Park purchasing PEF's distribution system in Winter Park as that transaction relates to PEF's loss of its Winter Park customers.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to certain positions and arguments presented in the testimony of Mr. Brubaker and Ms. Deronne regarding the subjects that I previously noted. I also describe the development and results of PEF's revised load forecast, which responds to intervenor requests to remove the City of Winter Park-related load and energy from the retail jurisdiction and add it to the wholesale jurisdiction.

Q. Have you prepared any exhibits to your rebuttal testimony?

A. Yes, I have prepared or supervised the preparation of four rebuttal exhibits, as follows:

- Exhibit No. ___ (JBC-9), Revised Minimum Filing Requirement Schedules F-7 Forecasting Models – Historical Data and F-8 Assumptions.
- Exhibit No. ___ (JBC-10), Revised Energy Sales - Customers - Coincident Demand Forecast.
- Exhibit No. ___ (JBC-11), PEF Forecast Variance Review.
- Exhibit No. ___ (JBC-12), Forecast Comparison – Original vs. Revised.
- Exhibit No. ___ (JBC-13), 2003 Presentation to the Florida Public Service Commission Regarding Impact of Gas Prices on New Coal Capacity.

These exhibits are true and accurate.

II. Mr. Brubaker's Comments Regarding PEF's Generation Fleet.

Q. Are you familiar with Mr. Brubaker's comments regarding PEF's generation fleet?

A. Yes. Mr. Brubaker contends that PEF relies too heavily on generation units that are fueled by natural gas. He also contends that PEF has not "seriously analyzed" adding a new base load, coal-fired plant into its generation fleet and suggests that PEF should have pursued coal-fired generating units "more aggressively." While Mr. Brubaker appears to imply or suggest that PEF's fuel costs could have potentially been reduced had PEF made different generation choices, he comes to no real conclusion in his testimony and instead only urges the Commission to keep PEF's generation fleet choices "in mind while it evaluates PEF's requests" in this rate case proceeding.

Q. Do you agree with any of Mr. Brubaker's analysis?

A. No, I do not. In fact, Mr. Brubaker performs no meaningful analysis at all. Mr. Brubaker offers no economic analysis to support any of his statements, nor has he relied on or presented any pertinent factual information to substantiate his claims. Mr. Brubaker's lack of analysis is evidenced by the fact that he is unable to offer any substantive conclusions in his testimony and instead simply urges the Commission to keep certain "sound bites" from his testimony "in mind" as it rules on issues in this case.

Q. Has PEF over relied on gas-fired generation units as Mr. Brubaker suggests?

A. Not at all. First, it is important to note that this Commission reviewed, held workshops on, and deemed suitable, PEF's Ten Year Site Plans (documents that specifically detail PEF's forecasts for future generation plant types) for each of the years that Mr. Brubaker questions. Additionally, this Commission has also approved the reasonableness and prudency of each and every one of the gas-fired generation units that Mr. Brubaker criticizes. In essence, therefore, Mr. Brubaker – using hindsight analysis -- is questioning the Commission's judgment as well as PEF's on this topic.

As to the "substance" of Mr. Brubaker's comments, gas-fired generation units are needed in PEF's fleet for intermediate and peaking load service, which is PEF's current load growth area. PEF's existing base-load fleet has significant resources to adequately handle projected base-load requirements through 2014, and, at this time, PEF has no need for base-load generation until 2015-2016. As required by Florida law, life cycle economics are a major driver of PEF's decisions on additions to its generation fleet, and PEF's reliance on a particular type of generation unit at any given time is determined by PEF's needs and by best cost practices that balance the type of generation needed with the most cost effective impact to its customers. PEF has employed such a process with respect to each of its additions to its generation fleet, and this has allowed PEF to maintain a prudent and diverse generation fuel mix while making the most cost effective choices for its customers.

Third, even if there were any merit to Mr. Brubaker's assertions, which there is not, Mr. Brubaker is attempting to use "20/20 hindsight" to second guess decisions that were made and approved based on facts, needs, and conditions as they existed at the time generation choices were made. If PEF were to employ Mr. Brubaker's "hindsight" approach to building generation units, PEF would never be able to build anything at all because it would have to necessarily wait until all future facts and variable were known before making a decision.

Q. Is Mr. Brubaker correct in his assertions that PEF has not been serious enough in evaluating and pursuing coal-fired generating units?

A. Not at all. Either Mr. Brubaker does not know, or he fails to mention, the fact that two years ago, I provided a presentation to the Commission regarding coal plant development issues as part of PEF's Ten Year Site Plan hearing. Slides from that presentation are included with this testimony as Exhibit No. ___ (JBC-12). In that presentation, PEF specifically addressed and evaluated the value of coal development versus natural gas. Additionally, PEF briefed the Commission on its significant concern over the delivered fuel cost spread between natural gas and coal, and the potential for any fuel savings from coal being offset or even overtaken by the significantly higher capital risk exposure that solid fuel development requires. PEF also addressed the fact that coal plant costs may be drastically affected by environmental and other legislation, potentially making gas-fired units cheaper on a total dollar basis. Additionally, PEF explained that it is in the best interest of PEF and its ratepayers for PEF to carefully monitor unfolding relevant federal legislation and the potential for alternative generation incentives before making a decision on base-load fuel types. As I mentioned before, the Commission, fully aware of all these issues, deemed PEF's Ten Year Site Plan suitable two years ago when coal-fired generation was addressed in detail. The Commission has also deemed suitable all of PEF's subsequent Ten Year Site Plans. Thus, Mr. Brubaker's naked assertions that PEF has not seriously considered coal-fired units is belied by the significant consideration that both PEF and this Commission have given to coal-based generation issues.

III. Ms. Deronne's Comments Regarding the Winter Park Sale.

Q. Are you familiar with Ms. Deronne's comments regarding the impact of the City of Winter Park purchasing PEF's distribution system in Winter Park as that transaction relates to PEF's loss of its Winter Park customers?

A. Yes. Ms. Deronne criticizes PEF for not quantifying the impact of PEF's loss of its customers in the City of Winter Park.

Q. Why did PEF not include a quantification of that impact in its initial filings in this matter?

A. The closing of the sale of PEF's electric distribution system in Winter Park to the City of Winter Park did not take place until June 1, 2005, and PEF naturally could not account for the loss of its customers in Winter Park as a matter of fact until the sales transaction was actually completed. Indeed, PEF and the City were still making adjustments to the number of actual customers that would be served by the City versus those that would remain with PEF up until a few days before the closing took place.

Once the Winter Park closing was finalized, PEF began the process to update certain portions of its rate case filing to account for the loss of customers and equipment items that were sold to the City. In doing so, PEF took into consideration recent sales forecasts that were prepared in anticipation for PEF's upcoming fuel adjustment docket as well as the annual budget development process. Given the Commission's directive in Docket No. 840001-EI, Order No. 13694 that a utility should notify the Commission of "material and significant changes in the basic assumptions supporting a company's request," PEF updated its entire forecast to incorporate material changes in the projections therein as well as to account for the most recent customer, energy, and coincident peak demand information available, including more recent economic and demographic projections. PEF used this new information to quantify the impact of the Winter Park sale. Using this procedure, PEF has recently completed amended schedules that include the impact of transferring its retail customers in Winter Park to the City of Winter Park in conjunction with PEF's updated forecasts. Those schedules are included with this testimony as Exhibit Nos. ______ (JBC-9, 10, 11, and 12).

Q. Why did PEF perform the updates to its forecast that you just discussed?

A. The forecast is being updated for two reasons. The first reason is in response to intervenor requests that PEF update its case to incorporate the loss of the City of Winter Park as a retail jurisdictional customer and to show Winter Park as a wholesale customer. The second reason is to incorporate the most current information known to the Company as of this filing where such information constitutes a material change to the case. As mentioned before, PEF, while following its normal schedule of updating the annual corporate budget and fuel filing processes, has just completed the load and energy forecast phase and determined that the level of projected energy sales -- over and above the removal of Winter Park -- has changed materially enough to amend its filing. My Exhibit No. __ (JBC 10) details the revised test year forecast of customers and energy sales.

Q. Please explain the reasons for load forecast change.

A. The basic reason for updating the load forecast – besides removing Winter Park -- has been the divergence between weather normalized actual energy sales and the forecasted sales originally filed in this case. Material unfavorable energy sales forecast variances have occurred during the first six months of 2005. A table showing the year-to-date June 2005 forecast variances for billed accounts and MWH energy sales is presented in Exhibit No. ___ (JBC-11) "PEF Forecast Variance Review." What one notices from that exhibit is that PEF's customer growth has been stronger than expected while retail weather normalized energy sales have been significantly weaker than expected. The revised forecast incorporates a higher customer projection but a lower energy sales projection compared to the originally filed case. Also, the timing of the PEF budget development process involved a scheduled review and update of the company load and energy forecast during the June/July time frame. Updates of all economic and demographic variables from data sources (Economy.Com and University of Florida) were available and incorporated into the update. These latest assumptions were run through the PEF load forecasting models resulting in the revised load forecast.

Q. What are the reasons for the lower energy sales projection?

A. As shown in Exhibit No. ___ (JBC-11) every customer class was experiencing unfavorable energy sales forecast variances. The retail jurisdiction had an unfavorable variance of over 600,000 MWH through June. Each class has its own reasons, but I can broadly say that weak customer growth is not one of them. Housing construction has continued at an accelerated pace, resulting in higher than expected customer growth. On the energy consumption side, the residential, commercial, and public authority customer classes reflect a significant deviation from the original forecast in average energy usage per customer. The "average" customer in these classes is not consuming as much power as originally projected. PEF's load forecasting models, which for these three customer classes project average kWh use per customer, produced lower projections in each case using more current projections of each required economic driver. In the industrial class, the phosphate mining sub-sector has not even consumed the same amount of energy as last year-to-date, never mind kept pace with a projected level that reflected an increase. A projected mine expansion by one customer, which has not materialized, and higher "self service" cogeneration on the part of another mining customer, have resulted in a minus 12.1% unfavorable energy forecast variance to this class sub-sector. Another industrial customer, a citrus processor, decided to not even start up its typical seasonal processing cycle due to the loss of its fruit supply due to hurricane damage. Finally, a large telecom manufacturing customer has given notice that it will be terminating operations at year end 2005. These last two examples are reasons why the industrial, non-phosphate sub-sector now has a lower MWh energy projection.

Q. In summary terms, what is the impact in this proceeding of PEF's loss of the customers that PEF sold to Winter Park, taking into consideration PEF's revised sales forecasts?

A. On a billed basis, test year customers estimated to have been lost due to the transfer of 14,955 retail customers in Winter Park to the City is an energy impact of 473,563 MWh.

Q. Does this conclude your testimony?

A. Yes.

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.

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