BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050078-EI

In the Matter of

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

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

VOLUME 5

Page 557 through 745

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 4.)

DIRECT TESTIMONY OF HUGH LARKIN, JR.
ON BEHALF OF THE CITIZENS OF FLORIDA
BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 050078-EI

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Hugh Larkin, Jr. I am a Certified Public Accountant licensed in the States of Michigan and Florida and the senior partner in the firm Larkin & Associates, PLLC (L&A), Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.) Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes. I have testified before the Florida Public Service Commission on numerous occasions during the past 29 years. I have also testified before Public

Service/Utility Commissions in 35 state jurisdictions, United States District Courts, the Federal Energy Regulatory Commission and the Canadian Natural Energy Board.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I, identified also as Exhibit ___(HL-1), which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel (OPC) to review the rate request of Progress Energy Florida, Inc. (PEF or Company). Accordingly, I am appearing on behalf of the Citizens of the State of Florida (Citizens).

Q. ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL IN THIS CASE?

A. Yes. James Rothschild, Jacob Pous, and Helmuth W. Schultz, III and Donna M. DeRonne, of my firm, are also presenting testimony. (Mr. Pous' testimony is being sponsored jointly by OPC and the Florida Industrial Power Users Group).

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I will address, in order, the Company's Overall Financial Summary; Policy Issues; and Rate Base.

II OVERALL FINANCIAL SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF THE IMPACT OF ALL OPC WITNESSES ON THE PROJECTED 2006 TEST YEAR AND THE RECOMMENDATION REGARDING THE CHANGE IN RATES WHICH RESULTS FROM THOSE RECOMMENDATIONS?

A. Yes. As shown on the summary presented by OPC's witness Donna DeRonne, the rates currently in affect for PEF should be reduced by $360,496,000. This includes the impact of each of the witnesses for OPC's recommended adjustments and the amortization of the surplus reserve for depreciation and amortization.

III. POLICY ISSUES

Q. WHAT ISSUES WILL BE DISCUSSED UNDER THE HEADING "POLICY ISSUES"?

A. I will be addressing the following policy issues: Surplus Accumulated Reserve for Depreciation and Amortization and Deferred Income Taxes Debits included as a reduction of cost free capital provided by ratepayers.

Surplus Accumulated Reserve for Depreciation and Amortization

Q. BOTH THE DEPRECIATION STUDY FILED BY PEF WITH THE COMMISSION AND THE ANALYSIS OF THAT STUDY BY JACOB POUS OF DIVERSIFIED UTILITY CONSULTANTS, INC. SHOW THAT THE RESERVE FOR DEPRECIATION AND AMORTIZATION HAS AN ACCUMULATED BALANCE WHICH EXCEEDS BY FAR THE RESERVE THAT NEEDS TO HAVE BEEN ACCUMULATED. GIVEN THE

REMAINING LIVES, DEPRECIATION RATES AND CURRENT BALANCE IN THE ACCUMULATED RESERVE, WHAT SHOULD HAPPEN TO THIS SURPLUS RESERVE BALANCE?

A. As developed in detail in the testimony of OPC witness Jacob Pous, once needed adjustments are made, PEF's depreciation reserve excess is approximately $1.2 billion. Given the magnitude of the reserve excess, the Commission should take corrective action of the type it frequently has fashioned in situations involving reserve deficiencies of depreciation and amortization.

Q. WHAT POLICY HAS THE COMMISSION FOLLOWED IN THE PAST REGARDING DEFICIENCIES IN THE ACCUMULATED RESERVE FOR DEPRECIATION AND AMORTIZATION?

A. The Commission has ordered that deficiencies in the reserve for depreciation and amortization should be eliminated as quickly as possible. It would only be appropriate that the Commission apply to a significant reserve excess situation the remedy that it has found to be appropriate in similar situations regarding reserve deficiencies. That is, the surplus should be eliminated from the reserve as soon as possible. The Commission has on a number of occasions ordered that reserve deficiencies be amortized over a four or five-year period.

Q. CAN YOU PROVIDE SOME EXAMPLES OF SUCH SITUATIONS?

A. Yes. In each of the following dockets, the Commission determined that the recovery of a deficiency in a reserve was appropriate over a short period of time:

Company	Docket No.	Order No.	Date
General Telephone Co.	840049-TL	14929	09/11/85

The Commission stated in regards to a depreciation reserve deficit:

> "We believe that it is in the interest of both Gentel's customers and its stockholders that the Company's $32,138,000 deficit be written off in as short a time as practicable. In this case we find that a five-year period is appropriate."

Company	Docket No.	Order No.	Date
United Telephone Co.	871269-TL	18736	01/26/88

The Commission stated in regards to acceleration of an amortization:

> "Upon review, we will approve United's proposal to make a one-time charge to depreciation of $14,589,704 in 1987"
>
> \- - - - - -
>
> "This action, as modified, will comply with our policies of correcting reserve imbalances as rapidly as possible…"

Company	Docket No.	Order No.	Date
Gulf Power	880053-EI	19901	08/30/88

> "For the year 1988, the approved amortization expense shall be applied to the write-off of the deficit."

Company	Docket No.	Order No.	Date
City Gas Company	890203-GU	22115	10/31/89

The Commission approved the continuation of a reserve deficit amortization to be applied to "prospective" reserve deficits.

"Ordered that the $47,934 of expense which had been applied to the 'Historic' reserve deficit through the year 1988 be added in 1989 and subsequently to the $28,166 expense associated with the write-off of the 'prospective' reserve deficit, ..."

Company	Docket No.	Order No.	Date
Alltel Florida, Inc.	891026-TL	23833	12/04/90

The Commission stated in regards to reserve deficiency:

"A five year write-off period for this deficiency appears to be as fast as economically practicable for this Company."

Company	Docket No.	Order No.	Date
Gulf Telephone Company	900599-TL	24004	01/22/91

The Commission authorized a write-off of a reserve imbalance:

"This imbalance is based on our present expectation for the replacement of copper cable by fiber and should be written off as fast as practicable. We find a two year period to be appropriate for the write-off of this deficiency."

Company	Docket No.	Order No.	Date
Southern Bell	820449-TP	12290	07/22/83

In this docket, the Commission noted that Southern Bell's reserve deficit was $265.6 million on a composite basis. The Commission order stated:

"That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period. Therefore, we are ordering a 5 year amortization period for this portion of the deficit."

The Company recovered $123 million over the 5 year amortization.

Company	Docket No.	Order No.	Date
United Telephone Co.	830870-TP	12857	01/10/84

The Commission ordered elimination of a $36 million reserve deficit by ordering two amortization schedules. The second was as follows:

> "That portion of the deficit that is attributable to past incorrect estimates of life and salvage factors and historic technological change and growth should be recovered over a shorter period . . . the amount to be amortized over a 5-year period is $32,435,000."

Company	Docket No.	Order No.	Date
North Florida Telephone	820477-TP	12864	01/12/84

The Commission authorized the following:

> "The Commission orders a 13 year amortization of $608,002 and a 5 year amortization of $3,721,295."

Company	Docket No.	Order No.	Date
Gulf Telephone	870964-TP	18642	01/04/88

The Commission approved the following:

"Initially, the prospective reserve imbalance was to be amortized over a 14-year term; however, we now believe its entire balance should be written off over the period 1987-1989."

Q. I NOTE THAT MOST OF THE EXAMPLES YOU GIVE ARE EITHER TELEPHONE COMPANIES OR GAS COMPANIES. HAS THE COMMISSION FOLLOWED THE SAME POLICY REGARDING ELECTRIC UTILITIES?

A. Yes. In Docket No. 970410-EI involving a Proposed Agency Action related to the Florida Power & Light Company (FPL), the Commission approved the continuation of an amortization of the underrecovery of a number of costs. The Proposed Agency Action would continue through the years 1998 and 1999 and maintain amortizations which would recover $1,140,392,000 of costs to FPL. The majority of the costs relate to nuclear decommissioning reserve deficiencies and depreciation reserve deficiencies.

FPL supported the continuation of the amortization which would have allowed FPL to collect the total of $1.1 billion over a four-year period.

In Docket No. 970410-EI, the Commission agreed with the FPL witness that eliminating the deficiency in the shortest time possible was beneficial.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMMISSION'S RATIONALE FOR AMORTIZING RESERVE DEFICIENCIES OVER A FAIRLY SHORT PERIOD OF TIME?

A. Part of the Commission's consideration was the fact that part of the deficiency which was amortized over a short period of time resulted from past misestimations of depreciation expense and decommissioning costs. It appears that the Commission reasoned that since these services had already been provided and that ratepayers had already received the benefit of such services, that it would be appropriate to recover such costs over a short period of time. This had the effect of charging to current ratepayers those costs and avoid spreading them to ratepayers far into the future. This practice of avoiding intergenerational inequities seems to be an underlying factor in the Commission's thought process.

Q. WOULD THE SAME PRINCIPLES BE APPLICABLE TO RESERVE EXCESSES?

A. Obviously, yes. The reserve excess grew out of past inaccurate estimates of depreciation and decommissioning costs. These over estimates were recovered from past ratepayers and since those services have already been rendered it would be appropriate to return, as soon as possible, to ratepayers any excess. This would have the same practical effect of avoiding intergenerational inequities, which the Commission recognized when it recovered deficiencies from ratepayers for the benefit of the stockholders.

Q. HAS PEF RECOGNIZED THE COMMISSION'S LONG-STANDING PRACTICE OF AVOIDING INTERGENERATIONAL INEQUITIES BY ALLOWING RECOVERIES OVER A RELATIVELY SHORT PERIOD OF TIME?

A. Yes, it has. In OPC's Second Set of interrogatories, Question 81, the Company was asked the following question and responded, in pertinent part, as shown below:

> 81. MMR Program. Explain why the net book value of the retired meters should be allowed to be recovered over a five-year period and provide the precedent relied on for recovery of the cost.
>
> **Answer:**
>
> Consistent with the FPSC's long-standing practice of avoiding intergenerational inequities in rate making practices and allowing appropriate recovery of otherwise unrecovered costs, the Company has proposed a 5 year amortization of the net book value of the retired meters. Normal plant and depreciation accounting practices for these meters would result in a recovery period for these unrecovered costs of likely more than 20 years.

As can be seen, the Company agrees that it is appropriate to recover costs over a short period of time when necessary to avoid intergenerational inequities. It would be unfair to ratepayers to not follow the same policy and principle in returning very large depreciation reserve excesses to ratepayers over a short period of time.

Q. HAVE THERE BEEN INSTANCES WHERE THE COMMISSION HAS ACTUALLY CHANGED RATES, THAT IS, INCREASED RATES TO RECOVER DECOMMISSIONING COSTS WHICH WERE CONCLUDED TO BE TOO LOW?

A. Yes. In Docket No. 810100-EU, Order No. 12356, issued August 12, 1983, regarding an investigation on the Commission's own motion into the appropriate accounting and ratemaking treatment of decommissioning and depreciation costs of nuclear powered generators, the Commission found it was appropriate to raise rates to recover additional decommissioning costs. The Commission determined that decommissioning costs should be separated from depreciation rates and raised significantly. The Commission found that it was not appropriate to wait until the next rate case in order to start recovering these costs. The Commission concluded the following:

(4) "The appropriate additional annual revenue requirement sufficient to permit each company to recover its additional expense associated with the above revision to its accrual and funding of its reserve is $12,474,046 for Florida Power & Light Company and $2,122,000 for Florida Power Corporation.

(5) Revision of the rates of each company to recover this additional revenue requirement is necessary to correct rates which are unjust, unreasonable, insufficient and unjustly discriminatory. Such revision should occur as soon as reasonably necessary. Each company is authorized to apply an adjustment factor to its customers' bills, as of October 1, 1983, until such time as its base rates are revised to recover this additional revenue requirement. The adjustment factor shall be determined in accordance with this order.

(6) Each company has incurred a revenue deficiency, as of January 1, 1983, due to the requirement to begin funding its

> decommissioning reserve as of that date and the requirement to revise its decommissioning accrual upwards. We deferred recovery of this deficiency until a later date. Each company should recover its deficiency via a one time adjustment factor calculated in accordance with this order, to be effective October 1, 1983, through March 31, 1984. The revenue deficiency for Florida Power Corporation is $186,733. The revenue deficiency for Florida Power & Light Company shall be determined in conjunction with the August fuel adjustment hearings."

As can be seen from the above quoted dockets, the Commission followed a policy of returning to stockholders in the shortest time possible any reserve deficiency. In the instance of nuclear decommissioning expense for electric utilities, the Commission raised rates for that cost when it was determined that rates were to low to recover the total found appropriate.

In the current docket, PEF is asking for a change in rates. The amount of depreciation expense requested by the Company directly affects the size of its proposed revenue requirements. In this proceeding the Commission has the opportunity to correct the reserve excess and reflect that corrective measure in the rates customers pay. Because of the magnitude of the reserve excess it might be appropriate to approach the matter in a manner designed and intended to address any potential concerns regarding the impact on PEF's financial integrity. OPC witness Jacob Pous has done so in his recommendation on how the reserve excess should be treated and returned to ratepayers for ratemaking purposes.

Accrued Deferred Income Taxes

Q. ARE THE DEFERRED INCOME TAXES SHOWN IN THE CAPITAL STRUCTURE PROPERLY STATED FOR RATEMAKING PURPOSES?

A. No, they are not.

Q. WHAT IS IMPROPER ABOUT THE LEVEL OF COST FREE CAPITAL SHOWN IN THE CAPITAL STRUCTURE ON SCHEDULE D-1a?

A. The deferred income tax credits represent income taxes paid by ratepayers that have not yet been paid to the United States Treasury. In essence, they are being held by the Company for payment to the Treasury in the future. Such credits are classified as an income tax liability. Because the Company enjoys the use of these monies supplied by customers until the time arrives to pay the taxes, they are treated as a source of cost free capital – i.e., the Company is not permitted to earn a return on them. For reasons I will explain below, these credits have been improperly reduced by PEF by the amount of deferred income tax debits. Deferred income tax debits, the "flip side" of deferred income tax credits, represent the increment of income taxes paid to the United States Treasury that are associated with the fact that certain of the expenses that PEF accrues in a given year are not deductible for tax purposes until a point in the future, when PEF will actually spend the money represented by the prior accrual.

Q. WOULD YOU PLEASE EXPLAIN IN MORE DETAIL HOW DEFERRED INCOME TAX LIABILITIES AND DEFERRED INCOME TAX ASSETS ARISE ON THE BOOKS OF PEF AND HOW THEY SHOULD BE TREATED FOR RATEMAKING PURPOSES?

A. Yes. Let's start first with an explanation of deferred income tax liabilities. These are credit balances on the Company's balance sheet, and they represent funds collected from ratepayers for income tax expenses prior to those taxes being due to the Treasury Department. In other words, ratepayers are paying income tax expenses in rates prior to the Company actually being required to make those payments to the U.S. Treasury Department.

Q. CAN YOU GIVE AN EXAMPLE OF HOW DEFERRED INCOME TAX LIABILITIES ARISE ON THE COMPANY'S BALANCE SHEET?

A. Although there are many sources of deferred income tax liabilities, the primary source is depreciation expense. Depreciation expense for tax purposes is calculated on a much different basis than depreciation expense for book purposes or for purposes of inclusion in rates paid by ratepayers. As an example, the nuclear plant on the Company's books, Crystal River 3 (CR3) is approximately 68% depreciated for book purposes at December 31, 2004. That is, plant cost has been charged as depreciation expense and recovered from ratepayers to the extent of approximately 68% of the cost. However, for income tax purposes, most of CR3 has been fully depreciated for a number of years. This is so because the depreciable life allowed for income tax purposes for nuclear plants is 15 years. That depreciation, computed for income tax purposes, was based on accelerated methods which allowed the Company to depreciate a greater portion of those facilities in the beginning years for tax purposes than in the latter years of the 15 year period. However, for book purposes, depreciation expense has been calculated on a straight line basis over the license period of the nuclear unit, which was 30 years. As you can see, there is a difference in depreciation for book and tax purposes. Ratepayers paid income tax expense in rates based on the longer lives of the nuclear plants, while the Company was paying income tax to the U.S. Treasury based on the shorter life of 15 years and accelerated depreciation. Thus, ratepayers were prepaying income tax expense prior to it being due to the U.S. Treasury Department. Since PEF had the use of these funds in its operations, they had a zero cost to the Company and are, therefore, included in the Company's capital structure as zero cost capital. Many commissions deduct zero cost capital directly from the rate base, which has the same effect of including them in the capital structure at zero cost.

Q. WON'T THE INCOME TAX EXPENSE PREPAID BY RATEPAYERS EVENTUALLY BE PAID TO THE U.S. TREASURY DEPARTMENT?

A. No, there will always be some balance in the deferred income tax liability account. This occurs because plant investment is not stagnate, but is dynamic, with new plant being added as old plant reaches the end of its depreciable life both for tax and book purposes. This tends to ensure that there is a prepayment by ratepayers, and thus, cost free capital is available to the Company on an ongoing basis.

Q. THAT EXPLAINS DEFERRED INCOME TAX LIABILITIES. WHAT IS A DEFERRED INCOME TAX ASSET AND HOW DOES IT ARISE?

A. Deferred income tax assets are payments to the U.S. Treasury Department of taxes on deductions which are not recognized by the Internal Revenue Code as deductions for income tax purposes in the same year in which they are recognized as expenses on the books of PEF.

Q. CAN YOU GIVE AN EXAMPLE OF AN EXPENSE WHICH IS RECOGNIZED FOR RATEMAKING AND BOOK PURPOSES, BUT IS NOT RECOGNIZED FOR INCOME TAX PURPOSES?

A. Yes. A major expense which is recognized for book purposes and included in rates, but not recognized for income tax purposes as a deduction in the year booked, is nuclear decommissioning accruals. While this future expense is recognized in the ratemaking process and included as an expense deduction in the ratemaking process, it will not qualify as a deduction for income tax purposes until the utility actually expends the money to decommission the unit in the future.

Q. WHY IS THAT SO?

A. Since no nuclear decommissioning cost has been incurred when the accrual is made, the IRS, does not recognize this as a cost for tax purposes. No decommissioning expense has been incurred as a result of accruing the future expenses therefore, the IRS does not recognize this as a current income tax deduction.

Q. PLEASE EXPLAIN HOW PEF IS REFLECTING THE DEFERRED INCOME TAX LIABILITIES AND THE DEFERRED INCOME TAX ASSETS IN THE CURRENT FILING.

A. PEF is offsetting the deferred income tax assets against the deferred income tax liabilities. This has the effect of reducing the cost free capital reflected in the capital structure, thus raising the overall cost of capital and, in effect, allowing the Company to earn a rate of return on the deferred income tax asset.

Q. WHAT IS WRONG WITH OFFSETTING THE DEFERRED INCOME TAX ASSETS AGAINST THE DEFERRED INCOME TAX LIABILITIES?

A. What is inappropriate about offsetting deferred income tax assets against the deferred income tax liabilities is that ratepayers are paying the tax which is represented by the deferred income tax asset in most instances. For instance, in the Commission's orders related to decommissioning cost, the Commission required a trust fund be set aside so that funds are available when the decommissioning actually occurs. However, the amount of dollars actually deposited in the trust fund is net of tax. In other words, ratepayers are paying a specific dollar amount, part of which is set aside in a trust fund for future decommissioning cost and part of which is used to pay the income tax on the decommissioning accrual because the accrual is not deductible for income tax purposes.

In Docket No. 810100-EU, Order No. 12356, dated 8-12-83 the Commission stated, on page 4:

"All parties propose funding of the decommissioning reserve net of tax. We agree. The deduction of decommissioning expense from taxable income at the time of decommissioning, in addition to the funded reserve, should provide sufficient funds to complete decommissioning."

In the docket quoted above, the Commission authorized FPC, now PEF, to collect in rates $4,349,072. The order required the Company to set up a funded reserve for decommissioning of CR3 when decommissioning is required. However, because the order allowed for the reserve to be funded "net of tax," the full $4,349,072 was not deposited in the funded reserve. Only the net of tax amount of $2,671,418 would have been deposited in the funded reserve. The difference, $1,677,654 ($4,349,072 x tax rate of 38.575% = $1,677,654), would have been paid to the Internal Revenue Service and the State of Florida as income taxes because the accrual of decommissioning cost is not a current deduction. The taxes paid to the Treasury Department, as shown above, would have been recorded on the Company's books as part of a deferred tax asset balance. It is this balance by which the Company is reducing the cost free capital on Schedule D-1a. It should be clear that ratepayers are paying $4.3 million, part of which is used to pay the income tax on a deduction not recognized by the Internal Revenue Service. To reduce the cost free capital by this amount would, in effect, charge the ratepayer a rate of return on a tax which he has already paid.

Q. SCHEDULE D-1a SHOWS COST FREE CAPITAL PRIOR TO ADJUSTMENTS OF $407,236,000. BY WHAT AMOUNT HAS THAT BEEN REDUCED BY PEF FOR DEFERRED TAX DEBITS?

A. PEF has reduced the cost free capital by $166,654,000 for accumulated deferred income tax debits in Account 190.

Q. DOES ALL OF THAT BALANCE PERTAIN TO DEFERRED INCOME TAX DEBITS RELATED TO THE DECOMMISSIONING TRUST FUND?

A. No. The Company's filing does not show the details of the balances in Account 190 – Accumulated Deferred Income Tax Debit. The FERC Form 1 for December 31, 2004 does have the detail of what is in the December balance. Of the $167,278,404, the balance at December 31, 2004, page 234 of the FERC Form 1, shows that $37,910,000 is related to nuclear decommissioning funds. This balance increased $7,447,000 between December 31, 2003 and December 31, 2004. The balance would increase by similar amounts for the years 2005 and 2006. I have added $7,447,000 for the year 2005, since that full amount would be reflected in the 13-month average for 2006. I have added one-half of $7,447,000 for the 13-month average ending December 31, 2006. The estimated balance for deferred income tax debits related to nuclear decommissioning is estimated to be $52,804,000.

The stipulation between the OPC and PEF in Docket No. 000824-EI, dated March 27, 2002, suspended the contribution to the decommissioning fund. The increase in the deferred income tax debit balance in Account 190 appears to be related to earnings on the trust fund balance. These earnings, when not tax exempt, are normally added to the trust fund net of tax. Therefore, the ratepayer is, in affect, paying the tax on the earnings and should not have the balance of cost free capital reduced by these increases in the deferred income tax debt in Account 190.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO CORRECT THE COST FREE CAPITAL SHOWN IN THE CAPITAL STRUCTURE?

A. Any deferred income tax debit balance or asset that has been treated as a reduction to the cost free capital should be removed, so as to reverse that effect, when such deferred income tax debits have been funded by ratepayers or is not related to regulated service. I am recommending that an increase of at least $52,804,800 be added to the capital structure for cost free capital.

Q. ARE THERE OTHER BALANCES IN THE ACCUMULATED DEFERRED INCOME TAX DEBIT BALANCE ACCOUNT WHICH APPEAR TO BE SUSPECT AS A REDUCTION OF COST FREE CAPITAL?

A. Yes. The Company is recording a deferred income tax debit for unbilled revenue. At December 31, 2004 this balance was $34,726,000. It is my understanding that the Company records unbilled revenue for ratemaking, book and tax purposes. I do not understand how there would be a difference between the amount of unbilled revenue recorded for ratemaking and book purposes and not recorded for income tax purposes which would give rise to additional income for tax purposes resulting in the deferred income tax debit. However, I have not made an adjustment for this amount in my recommendations. I do believe, however, that the Company should be required to demonstrate that any reduction to cost free capital by the balance in the accumulated deferred income tax debit, Account 190, results from income tax expense paid by the Company on a revenue or expense item recorded for ratemaking purposes, but treated differently for tax purposes. Only those taxes which have not been collected from the ratepayer should be a legitimate reduction of cost free capital.

IV. RATE BASE

Q. ARE YOU PROPOSING ADJUSTMENTS TO THE COMPANY'S PROJECTED TEST YEAR RATE BASE FOR THE TEST YEAR ENDING DECEMBER 31, 2006?

A. Yes, I am.

Q. ON WHAT SCHEDULES ARE YOUR PROPOSED RATE BASE ADJUSTMENTS SHOWN?

A. I have made adjustments to the Company's rate base on separate schedules labeled Exhibit No. ___ (HL-2), Schedules B-1 and B-2. I am also recommending other reductions to rate base as discussed in this testimony.

Q. WOULD YOU PLEASE DISCUSS EACH OF THE ADJUSTMENTS YOU ARE PROPOSING AND WHY EACH IS APPROPRIATE?

A. Yes.

Plant in Service

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE COMPANY'S PLANT IN SERVICE?

A. The rate base requested by the Company utilizes a projected test year ending December 31, 2006. That means the Company must project each balance by month of each component of the rate base, i.e., plant in service, accumulated depreciation, plant held for future use and working capital. It is unlikely that anyone could project balances almost two years into the future without inaccuracies affecting the balances. The best method of testing the Company's projection methodologies is to compare actual results to projections and draw a conclusion regarding whether the balance will be overstated or understated based on comparisons of actual to projected amounts.

Q. HAVE YOU PERFORMED SUCH AN ANALYSIS?

A. Yes. I have been able to compare the Company's projections of plant in service balances for the first five months of the 13-month average for the year ending December 31, 2005, which is the year prior to the projected test year.

Q. HAVE YOU PREPARED A SCHEDULE THAT SHOWS THE RESULTS OF YOUR COMPARISON?

A. Yes, I have. On Schedule B-1, I have compared the PEF projected plant in service balance to the actual plant in service balance as shown on PEF's Surveillance Reports filed with the Florida Public Service Commission (FPSC).

Q. WOULD YOU DISCUSS THOSE COMPARISONS AND YOUR PROPOSED ADJUSTMENT TO PLANT IN SERVICE?

A. On Schedule B-1 I have compared the actual balances of electric plant in service to the Company's projections on Schedule B-3, page 5 of 12, for the prior year ended December 31, 2005. This comparison of actual balances, as reported to the Commission in surveillance reports, to the Company's projected balances will indicate whether there is a trend in the Company's projection methodology. In other words, if all of the projections exceed the actuals in months in which the Company only had to project expenditures and retirements for five months into the future, then it is likely that same trend of over projecting plant balances would continue into the future and would affect the test year 13-month average ending December 31, 2006.

Looking at the results shown on Schedule B-1, each month, December 2004 through April 2005, show that the Company's projected plant in service balance exceeded the actual in every month. Actual data is available at this time only through April 2005.

Q. DIDN'T THE COMPANY HAVE THE ACTUAL DECEMBER 2004 BALANCE WHEN IT MADE THE PROJECTION FOR THE PRIOR YEAR ENDED DECEMBER 31, 2005?

A. Yes, it did. In fact, PEF used the actual balance for the month of December 2004 for the historical test year ended December 31, 2004. However, when making the projection for the year 2005, PEF did not use the actual balance for December 2004; rather, PEF used a budgeted balance which exceeded the actual by $40,765,000.

Q. WHAT RELEVANCE DOES THE YEAR 2005 HAVE TO THE PROJECTED TEST YEAR 2006?

A. The Company utilized the same projection methodology for both the prior year ended December 31, 2005 and the test year ended December 31, 2006. The 13-month average for the plant in service balance for the test year ended December 31, 2006 starts out with the same balance for December resulting from the projections for the prior year ended December 31, 2005. Any inaccuracies in 2005 are carried forward into the 2006 test year because the December 31, 2005 balance becomes the first month in the 13-month future test year average, and the same projection methodology is used.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING?

A. I have calculated the difference between the actual plant in service balance and the projected plant in service balance for each of the actual months available. I have also calculated the percentage difference by which the projected balance exceeded the actual balance. I then took the average percentage overstatement of the balance of plant in service to projected and applied it to the 13-month average plant in service balance projected by the Company on Schedule B-1 for the 13-months average ending December 31, 2006. This results in an adjustment to plant in service for the projected test year 2006 of $139,698,000 on a total Company basis. The jurisdictional adjustment is $129,459,000. This amount is reflected as a reduction of rate base by OPC witness DeRonne.

Q. DID YOU DO A SIMILAR STUDY RELATED TO THE ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION?

A. Yes, I did.

Q. WHAT WERE THE RESULTS OF THAT STUDY?

A. I found the average balance for the first five months of 2005 to be reasonably stated.

Construction Work In Progress

Q. SHOULD THE COMMISSION ALLOW ANY CONSTRUCTION WORK IN PROGRESS (CWIP) IN RATE BASE?

A. No, it should not. Construction Work In Progress, as the title designates, is plant that is not completed and providing service to ratepayers. It is neither used nor useful in generating, transmitting, or delivering current service to ratepayers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are, in fact, reasonably priced and are both used and useful in providing services on a current basis to ratepayers. Facilities in the process of being constructed cannot be used or useful. Their total cost and the basis on which they were constructed cannot be examined in the context of providing service to ratepayers. The ratemaking process therefore excludes, in most instances, all CWIP from earning a current rate of return or being included in rate base until such time as projects are completed and providing services to ratepayers.

For a public service commission to allow CWIP in rate base is to predetermine that costs are reasonable and that the project will be used and useful in providing service to ratepayers. As a general ratemaking principle, CWIP should be excluded from rate base and excluded from the ratemaking process until such time that it is actually providing service to ratepayers.

Q. HAS THE FLORIDA PUBLIC SERVICE COMMISSION INCLUDED CWIP IN RATE BASE IN SOME INSTANCES?

A. Yes, it has. However, in those instances of which I am aware, the particular utility was in the midst of a large construction program, and there was a likelihood that the interest coverage ratio would decline below the coverage ratios required by bond indenture covenants.

Q. WAS FLORIDA PROGRESS (FLORIDA POWER CORP.) ALLOWED CWIP IN RATE BASE IN THEIR LAST FULL RATECASE DOCKET NO. 91089-EI, ORDER NO. PSC-92-1197-FOS-EI, DATED OCTOBER 22, 1992?

A. Yes.

Q. IN THAT DOCKET DID THE COMMISSION AUTHORIZE CWIP IN RATE BASE BASED ON THE NECESSITY OF MAINTAINING THE COMPANY'S FINANCIAL INTEGRITY?

A. There is no discussion in the order related to the reasoning behind allowing CWIP in rate base. It does not appear that any of the parties challenged the inclusion of CWIP in rate base based on the Commission's normal standard of only including CWIP in rate base when it is necessary to maintain the company's financial integrity.

Q. SHOULD THE COMMISSION APPLY IN THIS CASE ITS PAST STANDARD OF INCLUDING CWIP IN RATE BASE ONLY WHEN THE UTILITY DEMONSTRATES THE MEASURE IS REQUIRED TO MAINTAIN FINANCIAL INTEGRITY?

A. Yes, it should. As I have previously pointed out, CWIP is not used and useful and is not currently providing service to ratepayers.

Q. HAS PEF DEMONSTRATED THE BASIS FOR INCLUDING CWIP IN RATE BASE IN THIS CASE?

A. No, it has not.

Q. WHY, IN THE ABSENCE OF SUCH A SHOWING, SHOULD THE COMMISSION DENY PEF'S PROPOSAL TO INCLUDE CWIP IN RATE BASE?

A. When a utility undertakes a new construction project, the process of approving that project should include an analysis of the costs and benefits to be derived from the completion of the construction project. Projects are normally only approved by utility management when the present value of future revenues or savings exceeds the present value of the cost of completing the construction project. When a utility commission includes CWIP in rate base, it is allowing a return on that project prior to its placement in service and its generation of the benefit which was contemplated when the project was initially approved. The inclusion of a current return on that project, therefore, bestows on the company's stockholders a double benefit. That double benefit consists of the future benefit anticipated as a result of the approval of the project and the current benefit which allows a current return on that project.

Q. WHAT IS YOUR UNDERSTANDING OF WHY THE FLORIDA PUBLIC SERVICE COMMISSION HAS ALLOWED CWIP IN RATE BASE IN PRIOR CASES?

A. The justification used by the Public Service Commission was that because a particular utility was in the midst of a large construction program, that its financial integrity, i.e., its interest coverage ratio, would be compromised because of a large portion of earnings being generated by the Allowance for Funds Used During Construction (AFUDC), or no earnings being allowed on smaller projects where no AFUDC was being accrued.

The Florida Public Service Commission set out its policy regarding inclusion of CWIP in rate base and FPL's last litigated rate case, Docket No. 83046-EI. The Florida Public Service Commission stated the following:

> "As announced repeatedly in our more recent electric rate cases, our decision to include CWIP in rate base has been founded on our overriding concern of providing the particular utility with an opportunity to achieve and maintain adequate financial integrity. In this case, we have determined that even without the inclusion of any CWIP in rate base, FPL should be able to maintain its financial integrity in 1984 and 1985. Accordingly, we find that it is not necessary to include any CWIP or Nuclear Fuel in Process (NFIP)

in rate base in either 1984 or 1985 in order to maintain FPL's financial integrity."[1]

The April 30, 2005 surveillance report indicates that the times interest earned ratio for PEF is 6.49 (including AFUDC) and 6.37 (excluding AFUDC) for that 12-month period.

PEF had additions to plant in service in 2003 of $760 million and maintained an interest coverage ratio of 4.74 times without AFUDC and generated 41.24% of the fund internally. It should also be pointed out that the plant additions completed in 2004 were approximately $381 million and PEF, according to the earnings surveillance report, was able to generate 75.02% of the construction funds internally. The times interest earned ratio was 6.89 with AFUDC and 6.80 without AFUDC. Plant additions for 2005 are projected to be approximately $654 million while the 2006 projected plant additions projected at $324 million. It does not appear that PEF's coverage ratios, which have ranged from 5.35 to 5.45 range in 2002 and 2003 and 6.89 for the 12-month ended April 30, 2005 would be detrimentally affected to the point where CWIP would need to be included in rates in order to maintain a coverage ratio above the requirements of bond covenants.

Q. DOES THE COMMISSION RULE 25-6.0141 ON THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION DETERMINE WHETHER PROJECTS ARE INCLUDED IN RATE BASE OR NOT?

[1] Docket No. 830465-EI, p. 14. Decision Nos. 13537 and 13948.

A. No, it does not. The rule determines that long-term projects of a certain magnitude will accrue AFUDC and that shorter term projects will not. In my opinion, the rule recognizes the fact that projects which are completed over a shorter period of time, i.e., less than one year, will provide the Company a return by either increasing sales or decreasing operating costs and, therefore, do not require an AFUDC return. Other more long-term projects may require the accrual of AFUDC because of the length it takes to complete these projects. However, that does not dictate that these projects should be considered for inclusion in rate base. Obviously, if a company constructs a new facility as PEF is or has done, there is an economic need for this capacity. If that is the case, then the return should be provided through the project as it is added, which will either increase sales or reduce costs. For these reasons, I have excluded CWIP from rate base.

Plant Held for Future Use

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO PLANT HELD FOR FUTURE USE (PHFFU)?

A. Yes, I am.

Q. WHAT ARE THOSE ADJUSTMENTS AND WHAT IS THE BASIS FOR THOSE ADJUSTMENTS?

A. The Company has projected the same balance as the prior year for PHFFU for each of the months of the 13-month average prior year ending December 31, 2005. It has projected the same balance in plant held for future use for each of the months of the 13-month test year ended December 31, 2006. That balance is $7,921,000 on a total Company basis. This is the same balance which appeared in the Company's Form 1, page 214, for the years 2003 and 2004. The Company's Form 1 indicates that the majority of these costs representing land and land rights were to be placed in service in May 2005. The balance to be placed in service at May 2005 is $6,459,553. If the Company's FERC Form 1 is correct, there will only be a balance in plant held for future use after May 2005 of $1,461,721. The Company has projected the in service date of this property to be May 2005 in each of the years 2003 and 2004. It is only appropriate that this balance be adjusted to comport with the Company's projections which would be made with the same accuracy as the Company's projections of other test year budgets and projections. The adjustment I am recommending is a removal of $6,459,000 from PHFFU on a total Company basis and $4,437,000 on a jurisdictional basis.

V. WORKING CAPITAL

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S WORKING CAPITAL CALCULATION?

A. Yes, I am proposing several adjustments to the Company's working capital allowance. These adjustments are shown on Schedule B-2.

Over Recoveries

Q. COMPANY WITNESS JAVIER PORTUONDO HAS MADE SEVERAL ADJUSTMENTS TO THE WORKING CAPITAL CALCULATIONS CONTAINED IN THIS TESTIMONY. WOULD YOU PLEASE DISCUSS THOSE ADJUSTMENTS WHICH YOU THINK ARE INAPPROPRIATE?

A. Yes. In the Company's rate base calculation of working capital, Mr. Portuondo has removed an over recovery of Energy Conservation Cost Recovery from the working capital calculation. This is in violation of prior Commission orders and policy. In PEF's (FPC) last rate order, Docket No. 910890-EI, Order No. PSC-92-1197-FOF-EI, dated October 22, 1992, the Commission specifically rejected the position that Mr. Portuondo is advocating.

Q. DID MR. PORTUONDO POINT OUT THAT THIS ADJUSTMENT WAS NOT IN COMPLIANCE WITH PAST COMMISSION ORDERS?

A. No, he did not.

Q. PLEASE DISCUSS WHAT THE COMMISSION ORDERED REGARDING OVER AND UNDER RECOVERIES OF VARIOUS COST RECOVERY CLAUSES.

A. The Commission has always recognized that an under recovery of costs, which appears on the company's books as a receivable, should be removed from working capital because to include it in working capital would allow the company a double rate of return. The first rate of return would be recovered through the base rates since the increase in working capital for the under recovery would receive a rate of return. The second rate of return would be recovered by the Company because a rate of return is added to the under recovery and recovered through the adjustment clause. Thus, in order to insure that a double recovery is not provided on under recoveries of adjustment clauses, the Commission excludes those from working capital calculations. On the other hand, the Commission includes in working capital any over recoveries related to any of the recovery clauses. This is so, because to exclude them would require ratepayers to pay a rate of return on the over recovery. If the over recovery is excluded from working capital, working capital is then increased and the company's return increases by the amount of the dollar over recovery excluded from working capital. In effect, ratepayers would be paying a rate of return to themselves rather than having the company pay a rate of return when it returns the over recovery to ratepayers through the recovery clause.

In Docket No. 910890-EI, related to PEF (FPC), the Commission stated the following:

> "It has long been our policy to include net fuel and conservation over recoveries in working capital. This reduces working capital and consequently rate base. However, FPC excluded from working capital the net over recoveries of fuel and conservation expense in its 1992 test year and the net under recoveries in the 1993 test year.
>
> FPC receives interest on under recoveries and pays interest on over recoveries through the Fuel and Conservation Clause Adjustments. This acts as an incentive for the Company to make its projections as accurately as possible. If over recoveries were excluded from working capital, rate base would be increased and ratepayers would have to provide the interest to pay themselves."

As can be seen, this has been the policy of the Florida Public Service Commission for years. Mr. Portuondo's adjustment is in conflict with that policy of the Commission. I recommend that working capital be decreased by $8,144,000 on a total Company basis and the same amount on a jurisdictional basis since the Energy Conservation Clause recovery revenue is all retail and there is no wholesale jurisdiction involved.

Remove Job Orders

Q. THE COMPANY HAS PROPOSED AN ADJUSTMENT TO WORKING CAPITAL TO REMOVE JOB ORDERS. DO YOU AGREE THAT JOB ORDERS SHOULD BE REMOVED FROM WORKING CAPITAL?

A. Yes. However, the Company's adjustment does not appear to go in the right direction. The explanation for this adjustment on MFR Schedule B-2, page 2 of 6, Adjustment (8), is "To remove recoverable job orders." This would mean that if they are recoverable from someone else, then they are an asset and are a debit balance in working capital. To remove them, therefore, would require a reduction in working capital since it should be an asset.

Q. DOES THE COMPANY'S WORKING CAPITAL CALCULATION ON MFR SCHEDULE B-17, PAGE 2 OF 3, SHOW FROM WHICH ACCOUNT THE COMPANY IS REMOVING THIS AMOUNT?

A. No. However, it is included as part of the adjustment being made to "current and accrued assets and deferred debits." It appears to me that this should be a reduction of working capital instead of an increase in working capital. That is, the

Company's adjustment increases working capital by $26,567,000 on a total Company basis, rather than decreasing it by that amount.

Q. HAVE YOU EXAMINED THE COMPANY'S BALANCE SHEET TO SEE WHETHER THERE ARE ANY CREDIT AMOUNTS RELATED TO JOB ORDERS?

A. Yes, I have. I examined the April 2005 balance sheet account detail for Progress Energy Florida. The only balances with job order descriptions are in Account 186. None of these balances are credit balances which relate to recoverable job orders. I am, therefore, recommending that unless the Company can show how removing work orders recoverable from a third party can result in an increase in working capital, this adjustment must be reversed in order to properly reflect the removal of recoverable job orders from working capital.

Q. WHAT ADJUSTMENT ARE RECOMMENDING?

A. Since the Company's adjustment increases working capital by $26,567,000 when in reality it should reduce working capital by that amount, the Company's adjustment must be doubled in order to actually remove recoverable job orders from working capital. Therefore, the adjustment should be a removal of $53,134,000 on a total Company basis and $43,267,000 on a jurisdictional basis.

<u>Other Investments</u>

Q. WHY HAVE YOU REMOVED OTHER INVESTMENTS FROM WORKING CAPITAL REQUIREMENTS?

A. As the account title indicates, other investments are not utility investments and should receive a rate of return from some other source. They, therefore, should not be included in regulated services which require a rate of return.

Cash Balance

Q. WHAT IS THE REASON FOR REMOVING THE CASH BALANCE FROM WORKING CAPITAL REQUIREMENTS?

A. The Company's working capital requirement contains a significant dollar amount of cash on hand, i.e., total Company of $11,357,000. All holding companies that I am aware of have a cash management program that requires that collections of cash are immediately transferred to the parent company where they are invested in short-term day-to-day money market assets in order to earn a rate of return. Each day the Company receives notice from the bank as to what checks or payment vouchers have been received by the bank and an equal dollar amount is transferred from the cash management fund to the bank to cover these vouchers or payments. Unless PEF can justify what benefit ratepayers receive from the maintaining of $11.3 million in funds on a total Company basis, such a large cash balance should not be allowed in working capital. If PEF cannot demonstrate that the savings to ratepayers is greater than the overall rate of return required to maintain these funds, then this balance should be excluded from working capital.

Accounts Receivable Associated Companies

Q. WHY SHOULD THE ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES BE REMOVED FROM THE WORKING CAPITAL REQUIREMENT?

A. Associated companies are not customers of the retail operations of PEF. It is unlikely that the receivables due from these associated companies is reflected in the jurisdictional accounts of Progress Energy Florida. These are most likely wholesale transactions, or transactions between the regulated entity and non-regulated companies owned by Progress, the parent company. Ratepayers in Florida should not be required to pay a rate of return on receivables due from these companies. Unless Progress Energy Florida can demonstrate that any, or all, of the $11.9 million of receivables from associated companies are related to providing retail services, they should be excluded from the ratemaking process.

Allocation of Unbilled Revenue

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO THE ALLOCATION OF UNBILLED REVENUE?

A. PEF has allocated 90.84% of total unbilled revenue to the jurisdictional retail customers on MFR Schedule B-17, page 1 of 3. An analysis of the first five months of the year 2005 indicates that only 78.95% of the unbilled revenue pertained to retail customers. See the Company's Financial Statements for the months of January 2005 through April 2005. This allocation is based on the actual results reflected in the Company's balance sheets and is not based on projections. Additionally, this allocation should be higher because the City of

Winter Park has become a wholesale customer of PEF as of June 1, 2005. The city purchased its distribution system from PEF, which is discussed in more detail in the testimony of OPC witness Donna DeRonne.

Derivative Assets

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING REGARDING DERIVATIVE ASSETS?

A. I recommend the Commission remove from working capital the derivative assets that PEF included in its filing.

It appears that the assets included by PEF in working capital are the result of market to market derivative instruments. These assets do not appear to be actual cash expenditures resulting from cash transactions. Unless the Company can show that there is an outflow of dollars related to the derivatives, they should not be included in working capital requirements. The adjustment I am recommending is a reduction of working capital by $23,471,000 on a total Company basis and a reduction of $21,321,000 on a jurisdictional basis.

Employee's Receivables and Merchandise Inventory

Q. HAS THE COMPANY INCLUDED EMPLOYEES' RECEIVABLES IN WORKING CAPITAL?

A. Yes, it has. The Company has included "other accounts receivable" Account 143. This includes receivables due from employees for heat pump loans and employee appliance purchase loans. Ratepayers should not subsidize the Company's appliance sales. This amount should be removed from working capital. I have removed the average of employee receivables for the first four months of 2005. This amounts to approximately $840,000 on a total Company basis. The jurisdictional adjustment would be $763,000. In addition, merchandise inventory should be removed from Accounts 153-163. The amount of merchandise for the first four months of 2005 on average was $262,000. The jurisdictional amount would be $242,000.

<u>Prepayments Non-Utility Advertising</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT TO WORKING CAPITAL FOR PREPAYMENTS NON-UTILITY ADVERTISING.

A. In response to Staff Interrogatory No. 112, the Company shows a breakdown of the prepaid balance included in working capital. The major component of this prepaid balance is a payment to the Devil Rays for directory advertising and promotional fees. The Company has labeled this account in its response to the Staff as "prepayments non-utility advertising." This is not appropriate to be included within the working capital requirement because it is both promotional for the Company and is non-utility in nature. It is not clear where these expenses are charged when the prepayment is being written off. If it is written off in utility accounts included in the ratemaking process, the same level of expense should be removed from the operating income statement.

Two Spare Turbines

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REDUCE THE MATERIAL AND SUPPLIES ACCOUNT FOR TWO SPARE TURBINES.

A. The Company has projected that the material and supplies account will increase by $65.2 million between December 2003 and December of 2006. Part of the Company's explanation for this increase contained in its response to OPC's Interrogatory No. 82 is as follows:

> "…and two spare turbines expected to be used in the construction of the Hines 4 combined cycle at a value of $46.8 million."

The Company's purchase of two turbines to be used in the construction of Hines Unit 4 should have been charged to a Construction Work In Progress work order which accrues AFUDC. Ratepayers should not be required to pay a rate of return for equipment purchased for new construction. The appropriate accounting for this item, as I described above, is to open a construction work order for the construction of Hines Unit 4 and charge the spare turbines to that work order and accrue AFUDC on this item until they are installed in the Hines Unit 4. It is not appropriate to charge materials and supplies and earn a current rate of return on equipment that is not necessary for the operation of units currently in service.

Q. ARE THERE OTHER ADJUSTMENTS TO WORKING CAPITAL BEING SPONSORED BY OTHER WITNESSES FROM LARKIN & ASSOCIATES, PLLC SHOWN ON SCHEDULE B-2?

A. Yes, L&A witnesses' Schultz and DeRonne are each sponsoring an adjustment to working capital shown on lines 13 and 14 of Schedule B-2.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050078-EI

DIRECT TESTIMONY OF HELMUTH W. SCHULTZ, III

ON BEHALF OF THE CITIZENS OF FLORIDA

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Helmuth W. Schultz, III, I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory analyst in the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.) Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wasterwater, gas and telephone utility cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission. I have also testified a number of times before Public Service/Utility Commissions or Boards in other state jurisdictions.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Ex. ___ (HS-1), which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel (OPC) to review the rate request of Progress Energy Florida, Inc. (PEF or Company). Accordingly, I am appearing on behalf of the Citizens of the State of Florida (Citizens).

Q. ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL IN THIS CASE?

A. Yes. James Rothschild, Jacob Pous and Hugh Larkin, Jr. and Donna M. DeRonne, of my firm, are also presenting testimony.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. First, I will discuss the storm damage accrual, payroll components, incentive compensation, benefit expense and finally, the Company's new capitalization policy. Attached to my testimony is Ex. ___, (HS-2) which contains Schedules 1-6 that reflect the adjustments that I am recommending.

II. STORM DAMAGE ACCRUAL

Q. HAVE YOU REVIEWED PROGRESS ENERGY FLORIDA'S REQUESTED ACCRUAL FOR STORM DAMAGE?

A. Yes. Progress Energy Florida has requested that its annual storm damage accrual be increased $44 million from $6 million to $50 million. According to Company Exhibit No. __(JP-9) the Company wishes to collect $50 million a year over the next five years to build up its storm reserve to $180 million. That assumption would mean the Company would incur an average annual charge to the reserve of $14 million over each of the next five years. The Company's request is based on a February 2005 "Rapid Update to Progress Energy Florida Hurricane Risk Profile Memorandum of 2000." Company testimony provided as support for the $44 million increase in the accrual consists of two paragraphs in Mr. Portuondo's prefiled testimony and two paragraphs in Mr. Bazemore's testimony.

Q. IS THE COMPANY'S REQUEST TO INCREASE THE ANNUAL ACCRUAL BY $44 MILLION REASONABLE?

A. No. The Company's request is overstated by $37.5 million. The request is not appropriate because it ignores the historical charges to the reserve, relies on an updated study that is focused on the 2004 storms and assumes that storms similar to those that occurred in 2004 are not of an extraordinary nature. The Company's assumption is that $14 million, on average, will be charged annually, when historically the annual charge averaged $2 million.

Q. WHY SHOULD THE HISTORICAL CHARGES TO THE RESERVE BE CONSIDERED?

A. As shown on Exh.___, (HS-2), Schedule 1, the Company charged to the reserve, on average, $1,943,000 a year over the 10 year period 1994 to 2003. The highest amount charged to the reserve in any single year was $5,896,000 in 2001. That means the $6 million annual accrual currently allowed in rates was not exceeded once in that 10 year period. The accrual was sufficient enough to allow the reserve to increase to $40,916,000 as of December 31, 2003. The reserve represents funds advanced by current ratepayers for future storm costs. The facts that, prior to 2004, the annual cost for storms averaged less than $2 million a year and that the highest cost incurred in any one year was $5.9 million are significant in determining the level of annual accrual that is required to re-establish the reserve for a normal, recurring level of storm related costs.

Q. WHAT DO YOU MEAN BY YOUR STATEMENT THAT THE UPDATED STUDY FOCUSED ON THE 2004 STORMS?

A. According to the response to Citizens' Interrogatory No. 105, the updated study in question focused on an annual accrual from $40 million to $110 million because of the 2004 storm season. Despite factoring in the 2004 storm season, the study ignores the possibility of securitization and/or a surcharge for recovery of the unprecedented catastrophic storm costs incurred in 2004. To establish a reserve that attempts to recover the costs of hurricanes like those experienced in 2004 is neither appropriate nor consistent with current ratemaking theory.

Q. WHY IS RE-ESTABLISHING THE RESERVE BASED ON THE 2004 STORM SEASON NOT APPROPRIATE?

A. As shown on Schedule 1, the 10 year average cost for storms prior to 2004 was $1,943,000. If you determine a 10 year average with only the largest and the smallest cost storms included, the average increases to $13,353,000. Calculating the 10 year average based on Frances and Jeanne, the two mid-level cost storms, the average jumps to $21,743,000. Using all four of the Company's estimated 2004 costs, the 10 year average skyrockets to $33,153,000. The costs for 2004 were unprecedented, and the fact that the excess 2004 costs are being recovered through a surcharge is reasonable justification to exclude the extraordinary costs from the normal reserve determination. A base rate item is a normal operating cost, and the costs that are included in the reserve are included in base rates. While the reserve is to cover some level of storm costs, it is not established to cover the magnitude of costs incurred in 2004. In fact, in the Storm Cost Recovery proceeding (Docket No. 041272-EI) both the Company contended, and the Staff agreed, that the reserve is not intended to cover the level of cost incurred in 2004. Therefore, the cost incurred in 2004 should not be included in the determination of the annual accrual for storms.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT THE STAFF INDICATED THE RESERVE IS NOT INTENDED TO COVER THE LEVEL OF COST INCURRED IN 2004?

A. At page 41 of its memorandum, Staff states, "The record evidence suggests it would have been imprudent to require PEF's customers to fund in advance the <u>substantial additional reserves</u> that would be needed to cover the costs of catastrophic storms, which, statistically speaking, were unlikely to occur." (Emphasis added.)

Q. WHERE DID THE COMPANY ASSERT THAT THE RESERVE WAS NOT INTENDED TO COVER THE LEVEL OF COST INCURRED IN 2004?

A. At page 39, the memorandum cites the testimony of PEF witness Portuondo. Mr. Portuondo testified that it was neither practical nor cost-effective to provide coverage for all storm related costs the Company might experience and the annual accruals to the reserve were not designed to cover costs of potentially catastrophic hurricane seasons because studies that provide the basis for these accruals have shown a <u>low</u> probability that most severe storms or series of storms would impact the Company's service territory. In fact, the testimony cited continues with Mr. Portuondo's conclusion that the Commission does not want to collect from customers "significant additional reserves" to cover the costs of catastrophic storms that were unlikely to occur. Those significant costs are to be recovered if and when the need arises. The record is clear that the excessive level of costs in 2004 were unprecedented, catastrophic costs not intended to be included in the reserve that was established by base rates. And, because of the unprecedented series of events and costs incurred, the Company has been allowed to recover certain of those costs through a surcharge now that the need has arisen.

Q. WHAT DID YOU CONSIDER IN DETERMINING WHAT LEVEL OF ACCRUAL SHOULD BE INCLUDED IN BASE RATES?

A. The citation to Mr. Portuondo's testimony regarding the study in Docket No. 041272-EI indicates that the Company has a 23.3% chance of a storm occurrence and that 53% of the storms will impose costs of less than $5 million. The 10 year average storm cost from 1994-2003 is $1,943,000. Inflating the average using the Gross Domestic Price Inflator, in 2004 dollars, the annual accrual increases to $2,147,000. The Company's updated study, that factored in the 2004 storms, indicates that there is a 51.7% probability that at least $50 million of damage will occur over a five year period. As stated earlier, the Company's request of $50 million a year to establish a reserve of $180 million after five years would assume an average annual expense of $14 million. The estimated annual charges range from $1.9 million to $14 million. The reserve balance prior to 2004 was built up over a 10 year period. Historically, the charges have, on average, been relatively low and the current accrual was sufficient for storm costs that were likely to occur.

Q. WHAT CONCLUSIONS DID YOU REACH ABOUT THE RESERVE BALANCE AND THE ANNUAL ACCRUAL?

A. The Company's request is attempting to incorporate catastrophic level storm costs in the annual cost and ultimately in the desired reserve level of $180 million. As explained earlier, this is contrary to the Commission's intention, as described by Mr. Portuondo, to refrain from allocating catastrophic storm costs to ratepayers prior to a need for recovery of those costs. The request by the Company is not appropriate and should be disregarded. The historical average as inflated represents a normal level of recurring costs that can be expected going forward. However, I believe that instead of establishing a reserve of $50 million over 10 years that the $50 million should be established over five years. A $50 million reserve over five years will provide a cushion in the event that the average costs exceed the historical inflated average. It will also provide some coverage should another catastrophic season occur. Assuming $10 million a year for re-establishing the reserve balance and assuming an average expected annual charge against the reserve of $2.5 million, I am recommending an annual accrual of $12.5 million. As shown on Helmuth Schultz, Exh. ___, Schedule 1 this would reduce the Company's request by $37.5 million or $36,356,000 on a jurisdictional basis.

Q. DOES THE STORM ADJUSTMENT AFFECT RATE BASE?

A. Yes, it does. On Helmuth Schultz, Exh. ___, Schedule 1, page 2 of 2, I have reflected my adjustment of $18,976,000 to increase working capital as a result of the change I recommended in the annual accrual. I will note that the Company adjustment, although not in their favor, appears to be overstated because it assumes no charges will be reflected against the accrual in 2006. That would only be the case if the Company was assuming no storms in 2006.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT?

A. Starting with the Company's 2006 beginning balance of $6,515,000, I added my recommended annual accrual of $12,500,000 and deducted my estimated annual expense of $2,147,000, resulting in a year end balance of $16,868,000. My projected year end balance is $39,147,000 less than the Company's estimated year end balance of $56,015,000. The Company's average in working capital for the year 2006 is $28,008,000. My projected average is $8,434,000. The average adjustment is $19,574,000 or $18,976,000 on a jurisdictional basis.

III. Incentive Compensation

Q. HAVE YOU REVIEWED THE COST ASSOCIATED WITH THE COMPANY'S INCENTIVE COMPENSATION?

A. The Company's response to Citizens' Interrogatory No. 27 shows that the cost of incentive compensation increased significantly since 2002. In 2003, the cost increased 83% over 2002 and was $7.7 million (54.7%) over budget. In 2004, incentive compensation increased $14.1 million (18.8%) over 2003 and was $9.8 million (60.8%) over budget. The 2004 incentive compensation of $26 million was over twice the 2002 incentive compensation of $12 million. During the same three year period the employee complement remained relatively stable. The average employee base pay increased 4.1% in 2003 and 7.3% in 2004. The total average payroll per employee increased 9.4% in 2003 and 13.5% in 2004 with incentive compensation factored in. It is a concern that during this period of time base pay increases were not curtailed, overtime was progressively increased (some of which is attributed to the hurricanes), and incentive compensation soared.

Q. WHY DOES THE INCREASE IN INCENTIVE COMPENSATION CONCERN YOU?

A. Incentive compensation is theoretically "at risk" compensation paid for increased performance, performance that in theory contributes to the success of the Company by achieving financial and operating performance goals. The significant increases in the amount of incentive compensation awards should be indicative of the Company's increased successful performance. However, despite the increases in incentive compensation, which if warranted would imply corporate financial success; the Company is requesting an increase in its rates.

Q. IS THERE ANY INDICATION AS TO WHY THE INCREASES IN INCENTIVE COMPENSATION OCCURRED?

A. Yes, to some degree there is an indication that the goals are not as challenging as they should be. The Company was requested in Citizens' Interrogatory No. 29 to provide the goals and the comparable actual results by year for 2002 to 2004. Each year instead of increasing the corporate earnings per share goal the Company decreased the earnings requirement. Reducing the primary goal is contradictory and defeats the purpose of the incentive plan. The environmental index goal, despite being achieved in 2002, remained the same each year thereafter. The Energy Supply customer care goal remained the same in each year. I question the efficiency of such static or diminishing goals.

Q WHAT IS THE PURPOSE OF THE COMPANY'S INCENTIVE COMPENSATION PLAN?

A. In response to Citizens' Production of Document No. 34, the Company provided copies of its Management Incentive Compensation Plan (MICP) and its Equity Incentive Plan (EIP). The stated purpose of the MICP "is to promote the financial interests of the Sponsor and its Affiliated Companies, including its growth…" The plan intends to accomplish this purpose by:

- Attracting and retaining executive officers and other management-level employees who can have a significant positive impact on the success of the Company;
- Motivating such personnel to help the Company achieve annual incentive, performance and safety goals;
- Motivating such personnel to improve their own as well as their business unit/work group's performance through the effective implementation of human resource strategic initiatives; and
- Providing annual cash incentive compensation opportunities that are competitive with those of other major corporations.

Reducing the earnings per share makes it easier for a payout of incentive compensation and it does not promote the financial interest of the Company or ratepayers.

It is also interesting to note that the Progress Energy, Inc.'s Chief Executive Officer has sole and complete authority to select participants and to establish and <u>adjust</u> performance criteria. (Emphasis added.) The level of discretion available is a major concern because it allows for performance criteria to be adjusted during the test year that would allow for payment of incentive compensation when performance may not be at a level that would normally result in an award.

The purpose of the EIP is "to promote the interests of the Sponsor and its shareholders" by attracting key employees, motivating the key employees using "performance-related and stock-based incentives <u>linked to the interests of the Sponsor's shareholders</u>" and enabling key employees to "share in the long-term growth and success of the Sponsor and its Affiliates." (Emphasis added.) This stock plan is truly company oriented. I also do not believe that it is appropriate for ratepayers to pay for the cost of this extra benefit to select employees and then pay a return on that cost in future years.

Finally, the percentage of compensation that can be rewarded to individual members of management is significantly higher than the Employee Cash Incentive Plan (ECIP) percentage identified in the ECIP. The increased disparity in compensation combined with the fact that the plans purpose is to enhance shareholders value raises a concern as to where customer service falls on the priority list. When the purpose of the plan does not mention customers or customer service it is difficult to understand how the ratepayers interest is considered or how ratepayers will benefit from the plan.

Q. IS THE EMPLOYEE CASH INCENTIVE PLAN CUSTOMER ORIENTED?

A. No. In fact, the plan does not even have a stated purpose. The plan states that it "is designed to ensure a close link between pay and performance and to share the Company's financial success." That financial success is later described as "Progress Energy's performance in the marketplace." The plan states that it awards an employee only when individual performance meets certain expectations. The plan also states that achievement of the plan goals "will generally influence the amount of any base pay increases for the year." Reflecting on both statements one would have to question whether employees are rewarded twice for the same performance. First employees are rewarded in the form of a base pay increase and then employees are compensated a second time for the same performance with incentive compensation.

Q. SHOULD THE COMMISSION BE CONCERNED WITH THE COMPANY'S INCENTIVE COMPENSATION PROGRAM?

A. Yes. Clearly, the focus is shareholder oriented and the goals do not appear to provide a true incentive to provide superior performance that would justify an award. Instead, the plans appear to be designed with goals that almost guarantee a payout. The only question that remains is how much will be paid out. As discussed earlier, the actual payout exceeded the budget by more than 50% in both 2003 and 2004. It is not appropriate for ratepayers to fund the incentive compensation plans of Progress Energy when the purpose of the plan is to benefit shareholders and/or employees.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT BE MADE TO THE INCENTIVE COMPENSATION COSTS?

A. Yes. Incentive compensation expense should be reduced by at least $7,967,000 or $7,143,000 on a jurisdictional basis.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENT?

A. As shown on Ex. ___ (HS-2), Schedule 2, I started with the total amount of projected 2006 incentive compensation by type and multiplied that by the Company's applicable expense allocator. The expensed amount is $9,617,000 for the Employee Cash Incentive

Plan (ECIP), $2,474,000 for the Management Incentive Compensation Plan (MICP), and $684,000 for the Long Term Incentive Plan (LTIP) or Equity Incentive. As discussed earlier the ECIP is questionable because goals are not set to create a true incentive and the benefit from the performance, if any, is flowing to shareholders. Without any specific evidence that there is a benefit to ratepayers, the entire amount should be disallowed. However, I am only recommending a disallowance of $4,808,000 or 50% on the presumption there is a benefit to ratepayers that is at least equal to the benefit shareholders receive. Based on the equal sharing of benefits I am recommending an equal sharing of the cost. The 50% disallowance recommended is the shareholders' cost for Progress Energy's performance in the marketplace.

Q. WHY DID YOU REMOVE ALL OF THE MICP AND LTIP?

A. Once again, the goals are a concern and the plans are specifically focused on the financial results of Progress Energy. In addition, the plans are designed to generously reward management for achieving that financial result. Without sufficient operating goals that are tied to customer satisfaction and reliable service the ratepayers' best interests could be sacrificed to attain the financial results that would trigger the payment of incentives to management. The checks and balances are not sufficient to allow the cost of the MICP and LTIP to be included in rates. There is no significant identifiable benefit to ratepayers that would justify the cost or even a portion of the cost of either plan in rates. As shown on Exh. ___ (HS-2), Schedule 2, I recommend adjustments of $2,174,000 and $601,000, on a jurisdictional basis, for MICP and LTIP, respectively.

IV. Payroll

Q. IS THE COMPANY'S REQUESTED PAYROLL REASONABLE?

A. The payroll dollars in total are not being questioned, at this time. However, the Company's projected expense of $156 million for base pay and overtime is considered excessive and, as shown on Ex. ___ (HS-2), Schedule 3, a reduction of $7,985,000 or $7,253,000 on a jurisdictional basis is recommended.

Q. WHY IS AN ADJUSTMENT NECESSARY?

A. In 2002 and 2003, the Company expensed approximately 54% of its payroll, capitalizing the remaining 46%. In 2006, the Company increased the expense factor to 57% without providing any justification. This increase is not supported by testimony or the filing and should not be allowed.

Q. HAVE YOU IDENTIFIED WHERE THE INCREASE WAS CHARGED?

A. Yes. The Company's response to Florida Retail Federations (FRF) Interrogatory No. 17 provided a comparison of the 2005 and 2006 projections to the actual levels for the years 2002-2004. In my review of the cost by activity, I identified a significant increase in the distribution operations and maintenance expenses in 2005 and 2006. A comparison of 2006 to 2002-2004 is shown on Schedule 3, lines 11-15. The distribution operating payroll exceeds the three year average by over $14 million. Coincidentally, the Company's adjustment (No. 19) for a change in accounting is also increasing distribution operations and maintenance expense significantly. In reviewing the response to Citizens' Interrogatory No. 4, it was noted that the accounts being charged are accounts that include labor and are in the same group of accounts that reflect the budget increase described above. The combination of the two increases would result in an extraordinary level of payroll dollars in these accounts when compared to historical levels. The filing does not provide justification for an increase of this magnitude. The expense factor should remain at the 2002 and 2003 level of 54%.

Q. ARE THERE ANY OTHER CONCERNS WITH PAYROLL?

A. Yes. The Company's filing reflects some downsizing. It is not clear from the information that I have reviewed whether the downsizing captures the full impact of the proposed reduction. For example, Citizens' Interrogatory No. 75 requested that the Company provide for 2005 and 2006 the budgeted employee levels, the adjustments proposed, and the resulting employees complement included in the filing in jurisdictional NOI. The response identified the budget levels on Company Schedule C-35 and referenced two types of adjustments being made, but the response did not identify the complement included in the jurisdictional NOI. When requested in Citizens' Interrogatory No. 22 to provide a listing of the employee positions projected to be added in 2005 and 2006, the Company responded by stating: "There will be no employee positions added in 2005 and 2006." The statement is not entirely accurate as evidenced by Company Schedule C-35, which shows the 2004 employee count to be 4,084, 2005 is 4,130, and 2006 is 4,131. The Company, prior to adjusting for the organization realignment and mobile meter reading, did in fact add 47 positions during 2005 and 2006.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT FOR EMPLOYEES?

A. Not at this time. What I am recommending is that the Company be required to quantify the payroll expense it is reflecting in the 2006 year and the number of employees. It is not appropriate to provide a budgeted level as a starting point and not provide specific quantification of the changes so the requested cost can be readily identified.

V. Payroll Tax Expense

Q. WHY ARE YOU RECOMMENDING A REDUCTION TO PAYROLL TAX EXPENSE?

A. An adjustment to payroll tax expense is required to account for the recommended adjustment to incentive compensation. It reflects the effective tax rate and it reflects a proper allocation to expense. The adjustment, as shown on Exh. ___ (HS-2) Schedule 4, reduces expense by $3,314,000 or $3,062,000 on a jurisdictional basis.

Q. WHY IS THE EFFECTIVE TAX RATE USED?

A. The effective tax rate represents the actual effective tax that is paid on the actual payroll. In 2004 the actual effective tax rate was 7.7%. The 7.7% was multiplied by the adjusted total payroll, resulting in my adjusted total payroll taxes of $21,611,000 for 2006. The Company's assumed effective tax rate of 8% was not used because we are not aware of any justification for an increase.

Q. WHAT DID YOU MEAN THAT YOU REFLECTED A PROPER ALLOCATION TO EXPENSE?

A. According to the response to FAF Interrogatory No. 17, the Company expensed $15,039,934 or 64.4% of the projected payroll taxes. The Company expensed 57.8% of its projected 2006 payroll. Payroll taxes are based on payroll. The direct causal effect should require the tax to follow the payroll. Whatever percentage of payroll is charged to expense the payroll taxes should follow by applying the same allocation. In my calculation of payroll I used a 54.26% payroll; therefore, applying the 54.26% is consistent with the payroll expense recommendation. The jurisdictional reduction to payroll tax expense of $3,062,000 is appropriate and should be made.

VI. Healthcare Benefits

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PROJECTED MEDICAL EXPENSE?

A. Yes. Healthcare expense is overstated by $3,046,351 or $2,767,305 on a jurisdictional basis. According to the response to Citizens' POD No. 31, the Company calculated its healthcare benefit cost based on information available as of August 2004. The healthcare estimate included separate cost calculations for medical, dental and vision. The primary cost is medical and it was based on a projected 2004 participant cost of $5,054. Dental was estimated to be $463 per participant and vision was projected to be $65 per participant. As shown on Schedule 5, the actual 2004 cost per participant for medical, dental and vision combined was $4,607. Therefore, the Company's starting point is overstated and, because the 2004 estimate was inflated to determine the 2006 estimated cost per participant, the 2006 projected cost is also overstated.

Q. ARE THERE OTHER CONCERNS WITH HOW THE COMPANY CALCULATED THE 2006 PROJECTED COST?

A. Yes. In response to Citizens' Interrogatory No. 33, the Company explained how 2005 and 2006 were projected. It also explained why the 2005 cost exceeded the 2004 cost by 24%. The first concern is that the 2005 inflation trend was based on the 2004 trend at the time the estimate was made. As indicated earlier, the 2004 trend was high. The 2005 cost projection also did not assume any level of refund/rebate. Next, the average cost used is a total Company average. Based on the response to Citizens' POD No. 31, the Florida specific cost is approximately $500 less per participant than the total Company cost per participant. Finally, in reviewing the historical and projected allocations of cost to accounts it was noted that the actuals reflected a clearing account credit to Account 926 in each year 2002-2004. The credit ranged from $2.9 million to $7.6 million. The projected 2006 credit is only $356,609. This difference is presumed to be the primary reason why the healthcare expense factor jumped 9.1% from a historical average of 51.1% to 60.2%.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT FOR ACTIVE EMPLOYEES' HEALTHCARE EXPENSE?

A. As shown on Exh.___ (HS-2), Schedule 5, I started with the actual 2004 cost and divided that by the average number of full-time employees. The source for this is Company Schedule C-35. This resulted in an average cost per employee of $4,607 in 2004. The next step is to inflate the cost per employee for the estimated 2005 increase. The Company claimed it based its 12% estimate on the Company's projected 2004 costs that we now know was too high. Based on the information supplied by the Company in response to Citizens' POD No. 32, I opted to use the 7.5% increase that occurred in 2004 for 2005. (Citizens' POD No. 32 requested any studies utilized by the Company that compares medical costs per employee for 2004 and/or projections for 2005 and beyond.)

Q. WHY DID YOU USE THE 2004 INCREASE FOR 2005?

A. The Company based its 2005 and 2006 inflation assumptions on what was projected to be the 2004 increase. To remain somewhat consistent with the Company's approach, I chose to use the 2004 national average increase of 7.5%, per the Mercer Human Resource survey information that was provided in response to Citizens' POD No. 32. The information also included an outlook for 2005 that indicated employers expect plan costs to increase 10%, but the overall cost increase is expected to be only 6.6%. I considered the 6.6% to be too conservative.

Q. PLEASE CONTINUE WITH YOUR EXPLANATION OF HOW YOU DETERMINED YOUR ADJUSTMENT.

A. The use of the 7.5% inflation for 2005 increased the per employee cost to $4,953. That 2005 estimate was inflated by 10%, resulting in a 2006 estimated cost per employee of $5,448. I utilized a 10% inflation rate because I do not believe the 7.5% rate could continue for another year. The Company's 12% rate was not used in 2006 because, as stated earlier, the projected increase for 2004, which served as the basis for using 12%, did not materialize. I would also like to point out that the 10% inflation rate applied is to the total healthcare cost. The Company, for 2006, applied 12% to medical, 8% to dental and no increase for vision, so effectively the Company's 2006 increase was 11.7%.

The 2006 cost per employee of $5,448 was then multiplied by the 4,131 employees projected for 2006, as shown on Company Schedule C-35, resulting in a total healthcare cost of $22,506,612. That total was then multiplied by a 54.25% expense factor, resulting in my projected 2006 expense of $12,209,837, which is $3,046,351 less than the Company's proposed $15,256,188. On a jurisdictional basis expense should be reduced $2,767,305.

Q. WHY DID YOU USE A 54.25% EXPENSE FACTOR?

A. As stated earlier, I believe the Company's 60% expense factor is overstated because of its failure to adjust the expense in Account 926 consistently with a similar credit from the clearing account. The 54.25% represents an average of the 2002 and 2003 expense factor. That is consistent with the expense factor I recommend for payroll. The resulting actual healthcare average to be expensed of 54.25% is comparable to the actual payroll average of 54.26%. That would be expected, since the payroll cost allocation and the healthcare cost allocation are for the same group of active employees.

VII. Capitalization Policy

Q. HAVE YOU REVIEWED THE COMPANY'S REQUEST FOR A CHANGE IN THE COMPANY'S CAPITALIZATION POLICY?

A. Yes. The Company's filing includes an adjustment that prospectively shifts certain types of costs to expense that previously would have been capitalized on its books. The Company explained the reason for the change in response to Citizens' Interrogatory No. 4 as follows: "Based on a detailed review of existing practices and the corresponding assets being installed, it was determined that a majority of the outage and emergency work, and a portion of the indirect charges to capital, was not supported by a corresponding level of addition of units of property that had been estimated in previous studies." It was determined that a majority of outage and emergency costs, and a portion of indirect support costs, should be expensed rather than charged to capital. ***** BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** The Company implemented a change in the accounting policy pertaining to the indirect support costs during 2004 and the change in accounting policy regarding the outage and emergency work in 2005. In my review of the information provided by the Company with regards to the changes in accounting, I found inconsistencies and noted areas of concerns with the request.

Q. WHAT INCONSISTENCIES WERE IDENTIFIED?

A. First, PEF witness Javier Portuondo states on page 9 of his prefiled testimony that the "best practices" recommendation was "prepared by an independent accounting firm hired by the Company." The Company was requested in Citizens Interrogatory No. 68 to identify the "independent accounting firm" and explain why it was hired to perform the best practice analysis. The response stated "The firm used to evaluate the methodology and make best practices recommendations was <u>not</u> an independent accounting firm." (Emphasis added.) The response did not, as requested, explain why a firm was hired to perform the "best practices" analysis even though it was not an independent accounting firm. It must be clarified that it was not the "best practices" review that initiated the changes in capitalization policy, as implied in Mr. Portuondo's testimony. According to the response to Citizens' Interrogatory No. 4, the Company performed an internal review that verified Company concerns. The outside consultant was hired to corroborate the Company's study and to make recommendations on how to properly account for the costs in question. The outside firm retained was not an accounting firm, as Mr. Portuondo had indicated in his testimony.

The Company was asked in Citizens Interrogatory No. 232 if the prior and recently implemented capitalization policies at PEF were in compliance with the FERC Uniform System of Accounts (USOA). The response was "The Company's books and records have been and are in compliance with the FERC Uniform System of Accounts." In response to Citizens' POD No. 5, the Company stated *****BEGIN CONFIDENTIAL***** [redacted]

[redacted] ***END CONFIDENTIAL*** The information provided in testimony and in response to discovery is not sufficient or consistent enough for us to conclude whether the prior method of capitalizing costs would comply with the FERC USOA requirements.

Another inconsistency pertains to how the Company advised the various parties of the change and the impact the change will have on the Company's capital cost and expense. The Division of Economic Regulation was advised on December 16, 2004 of the change being implemented. The December 16, 2004 correspondence did not provide any detailed justification for the change. The Company's test year notification in this case, filed on January 28, 2005, made no specific mention of an accounting change as a significant contributing need for the filing. It was the initial filing on April 29, 2005 when the request for a change in accounting to be allowed in rates was officially made. According to the response to Citizens' Interrogatory No. 230, the Company has not requested permission for a change in the capitalization policy, but instead "The Company has informed the FPSC of the change in accounting procedures." In fact, the Company's 8-K to the SEC, dated December 16, 2004, states "The registrants do not believe that any regulatory action is necessary or warranted as a result of the accounting change." However, the 8-K disclosure then continues on to state that the Company could defer the adoption of the new methodology depending on the Commission's actions. It is not consistent to claim regulatory action is not necessary, but then state that the Company could defer adopting the new methodology depending on the Commission's actions.

Finally, the Company's filing makes no mention of whether this change could impact cost recorded in prior years, especially rate base. The Company's 8-K dated December 16, 2004 stated that if "regulators agree with our change in accounting methodology" there would be no impact on 2004. In Citizens' Interrogatory No. 234, the Company was asked if the regulators do not agree with the change to explain what impact that would have on 2004. The response did not answer the question. *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** The impact on prior years is not known at this time because the Company's responses were vague and/or evasive as to the quantification of costs.

Q. COULD THIS CHANGE IMPACT PRIOR YEARS?

A. Yes. The deciding factor is whether this is a correction of an error or a change in estimate. An error results from mathematical mistakes, mistakes in the application of accounting principles, or oversight or misuse of facts that existed at the time financial statements were prepared. An error will impact prior years. A change in estimate results from new information or subsequent developments and accordingly from better insight or improved judgment. An estimate change is made prospectively. Accounting principles dictate what should be capitalized and what should be expensed. The basic distinguishing factor is whether the cost incurred will benefit future periods or is it a cost that only benefits the current period. That distinguishing factor has not changed in recent years. A Company memo in June 2004 concluded that the change would be a change in estimate. The change in capitalization could be a correction of an error or a change in estimate. The decision is based on judgment. ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** Again, the information provided by the Company is insufficient to enable us to gauge the nature of the impact, if any, on prior years.

Q. WHAT CONCERNS DO YOU HAVE WITH THE REQUEST?

A. The first concern is whether plant is overstated because of an inappropriate allocation of costs. The period primarily of concern is the 2002-2004 timeframe. ***BEGIN CONFIDENTIAL*** [redacted] *** END CONFIDENTIAL*** The result was an overstatement of capital costs and an understatement of expense. It is my understanding no analysis was done for 2002 to quantify or estimate the impact of this change, but for 2003 the December 16, 2004 letter to the Director of Economic Regulation indicated approximately $33 million was capitalized that could have been expensed. As for 2004, I was unable to identify a conclusive estimate of the annual impact. That is a major concern. Based on the information reviewed, the Company adjustment is overstated and not fully justified.

Other concerns identified are: (1) the Company has not done an analysis to evaluate the impact of the change on 2006 had the proposed capitalization policy been implemented earlier; *** **BEGIN CONFIDENTIAL** *** [redacted] ***END CONFIDENTIAL***

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE REQUESTED CAPITALIZATION POLICY?

A. The Company's proposed accounting change for outage and emergency and indirect costs appears to have merit. However, quantitatively the Company has not supported the claimed impact on the test year; nor has it addressed possible carry-over impacts from years past. The concern with the quantification is significant and should be addressed. I am recommending that the Company's estimated impact on operating income and rate base be reduced by 50%, and the Company should be required to provide a quantification of the overstatement of rate base for 2002-2004 due to the questionable capitalization practice utilized during that period of time. Additionally, in the future, the Company should be required to provide detailed justification of any significant changes in accounting along with a detailed quantification of the impact on net operating income and/or rate base. My recommended adjustment, as shown on Ex. ___ (HS-2), Schedule 6, reduces operating expense $10,356,000 on a jurisdictional basis and increases rate base $25,673,000 on a jurisdictional basis.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DIRECT TESTIMONY OF DONNA DERONNE

ON BEHALF OF THE CITIZENS OF FLORIDA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PROGRESS ENERGY FLORIDA, INC.

DOCKET NO. 050078-EI

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Donna DeRonne. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wasterwater, gas and telephone utility cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission on several prior occasions. I have also testified before several other state regulatory commissions.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I, Exhibit ___ (DD-2), which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel (OPC) to review the rate request of Progress Energy Florida, Inc. (PEF or Company). Accordingly, I am appearing on behalf of the Citizens of the State of Florida (Citizens).

Q. ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL IN THIS CASE?

A. Yes. Hugh Larkin, Jr. and Helmuth W. Schultz, III, also of Larkin & Associates, are presenting testimony. Jacob Pous and James Rothschild are also presenting testimony. Mr. Pous is being sponsored by both the OPC and the Florida Industrial Power Users Group.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I first present the overall financial summary, calculating the overall revenue requirement recommended by Citizens in this case. The overall financial summary presents the results of the recommendations of each of the Citizens witnesses in this case. I then address various adjustments I am sponsoring in this proceeding.

II. OVERALL FINANCIAL SUMMARY

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I have prepared Exhibit__(DD-1), consisting of Schedules A, A-1, B-1, C-1 through C-7 and D. The schedules presented in Exhibit__(DD-1) are also consecutively numbered at the bottom of each page.

Q. WHAT DOES SCHEDULE A, ENTITLED "REVENUE REQUIREMENT" SHOW?

A. Schedule A presents the revenue requirement calculation, at this time, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the recommendations made by Citizens witnesses Hugh Larkin, Jr., Helmuth W. Schultz, III, Jacob Pous and James Rothschild. The calculation of the net operating income multiplier (or gross revenue conversion factor) is presented on my Schedule A-1. The adjustments presented on Schedule A which impact rate base can be found on Schedule B-1. The OPC adjustments to net operating income are listed on Schedule C-1. Schedules C-2 through C-7 provide supporting calculations for the adjustments I am sponsoring to net operating income, which are presented on Schedule C-1.

Q. WOULD YOU PLEASE BRIEFLY DISCUSS SCHEDULE D?

A. Schedule D presents Citizens recommended capital structure and overall rate of return based on the recommendations of Citizens witness James Rothschild. The capital structure varies slightly from that recommended by Mr. Rothschild and presented in his prefiled direct testimony as I have applied the adjustments to the capital structure necessary to reflect the impact of the adjustment to deferred income taxes sponsored by Citizens witness Hugh Larkin, Jr. and to synchronize Citizens' recommended rate base with the overall capital structure. The detailed calculations of these adjustments along with the allocation of the adjustments to the different components of the capital structure are presented on page 2 of Schedule D. On page 1 of Schedule D, I then applied Mr. Rothschild's recommended cost rates to the final recommended capital ratios, resulting in an overall recommended rate of return of 6.57%.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR PROGRESS ENERGY FLORIDA?

A. As shown on Schedule A, the OPC's recommended adjustments in this case result in a revenue decrease for Progress Energy Florida, Inc. of $360,496,000.

III. NET OPERATING INCOME MULTIPLIER

Q. ARE YOU RECOMMENDING ANY MODIFICATIONS TO THE NET OPERATING INCOME MULTIPLIER PROPOSED BY THE COMPANY?

A. Yes, I am recommending a revision to the net operating income multiplier (i.e., gross revenue conversion factor) proposed by PEF. In determining its proposed factor, PEF included a bad debt rate of 0.1743%. Later in this testimony, under the heading of bad debt expense, I am proposing a bad debt rate for the 2006 projected test year of 0.144%. On Schedule A-1, I replace the Company's proposed bad debt rate of 0.1743% with a more appropriate rate of 0.144% in determining the net operating income multiplier. This revision result in a net operating income multiplier of 1.6315 as compared to PEF's proposed multiplier of 1.6320. The revised multiplier is used in calculating the Citizens' proposed revenue sufficiency on Schedule A.

IV. RECOMMENDED ADJUSTMENTS

Q. WOULD YOU PLEASE DISCUSS EACH OF THE ADJUSTMENTS TO PEF'S FILING YOU ARE SPONSORING?

A. Yes, I will address each adjustment I am sponsoring below.

Rate Case Expense

Q. ACCORDING TO COMPANY MFR SCHEDULE C-10, PEF HAS PROJECTED TO INCUR $3 MILLION OF RATE CASE EXPENSE, WHICH IT IS PROPOSING TO AMORTIZE IN RATES OVER A TWO YEAR PERIOD. IS PEF'S PROPOSAL TO RECOVER $3 MILLION OF RATE CASE EXPENSE FROM RATEPAYERS REASONABLE?

A. No, it is not. Ratepayers should not be forced to fund a high level of rate case expense to be incurred by PEF in preparing and defending a request for an increase in rates when an increase clearly is not necessary or appropriate. PEF has requested an increase in base rates of approximately $205.6 million. As demonstrated on Schedule A, Citizens analysis shows that base rates should be reduced by $360,496,000. Even the Company's own information shows that it is overearning. According to PEF's April 2005 Rate of Return Surveillance Report, PEF indicates that its pro forma return on common equity is 12.50%. Based on the OPC's analysis and the Company's own surveillance reports, PEF is not a Company in need of an increase in base rates. Ratepayers should not be forced to pay for the costs incurred by PEF in both filing and attempting to defend an unjustified and unsupported increase in base rates, particularly when a decrease in rates is clearly justified and appropriate.

Q. CONSIDERING THE RETURN ON COMMON EQUITY EARNED BY PEF THUS FAR IN 2005, SHOULD THE COMPANY BE PERMITTED TO DEFER THE RATE CASE COSTS IT IS INCURRING FOR FUTURE RECOVERY?

A. No, it should not. The costs associated with the current rate case are being incurred and paid by PEF in the current period, 2005. It is anticipated that any new rates resulting from this case will be implemented on or by January 1, 2006. Thus, the rate case costs to be incurred by PEF should be recorded and expensed during 2005, not deferred. In its April 2005 Rate of Return Surveillance Report, the Company reported an FPSC adjusted and a pro forma adjusted return on common equity of 12.50%. If PEF were to expense the costs it has projected to incur for the rate case in the current period (i.e., 2005), it would still be earning a proforma adjusted rate of return of over 12.35%. In the current case, PEF has requested a rate of return on equity of 12.30% prior to its ROE bonus, and 12.8% including the bonus for past performance. Considering PEF's earnings in the current period in which it is proposing to defer the rate case expense it is incurring, it is not appropriate to defer these costs to charge to ratepayers in the future. Thus, I recommend PEF's proposed deferral and amortization of rate case expense be disallowed and PEF be required to expense the costs in the current period as incurred. Earnings realized by PEF in 2005 year to date provide it a more than adequate means of recovering its rate case costs in the current period.

Q. IF THE COMMISSION DISAGREES WITH YOUR RECOMMENDATION THAT RATE CASE COSTS INCURRED BY PEF BE EXPENSED IN THE CURRENT PERIOD WITH NO DEFERRAL AND NO FUTURE AMORTIZATION IN RATES, ARE ANY ADJUSTMENTS TO PEF'S PROECTED RATE CASE EXPENSE WARRANTED?

A. PEF provided copies of agreements it has with several outside consultants and legal counsel for participation on behalf of PEF in the current rate case in response to OPC POD No. 48. These pages of the agreements providing the hourly rates have been identified as confidential by the Company. Based on the response, I am concerned that the rates being charged by the outside consultants are excessive.

Q. PLEASE EXPLAIN.

According to the agreements, James Vander Weide, is billing at a rate of $375 per hour. Charles J. Cicchetti's services are billed at a rate of $475 per hour.

If the Commission allows PEF to defer the costs, I recommend that the actual invoices supporting the actual costs incurred by PEF be closely scrutinized. I also recommend that 50% of the projected hourly costs associated with the outside consultants retained by PEF be shared 50/50 between ratepayers and shareholders. PEF is free to retain the level of experts it chooses; however, ratepayers should not be burdened with excessive or unreasonable rate case costs.

Q. PEF'S FILING INCLUDES $2,250,000 IN RATE BASE FOR PROJECTED 2006 AVERAGE UNAMORTIZED RATE CASE EXPENSE. IF THE COMMISSION ALLOWS PEF TO DEFER RATE CASE COSTS CURRENTLY BEING INCURRED FOR RECOVERY, SHOULD THE COMPANY BE PERMITTED TO EARN A RETURN BOTH OF AND ON THOSE COSTS?

A. No. If the Commission determines that the rate case costs being incurred during 2005 should be deferred for recovery beginning in 2006, which I do not recommend, the

Company should not be allowed to earn a return both of the funds via amortization in expense and on those funds through inclusion in rate base of the unamortized balance. As previously pointed out, in the current period PEF is earning a return that is more than adequate to cover its rate case costs during 2005. To allow the costs to be deferred and to require ratepayers to also pay a return on those funds when current earnings are sufficient to cover such costs would be unfair.

Q. IS THE TWO YEAR AMORTIZATION PERIOD PROPOSED BY THE COMPANY REASONABLE?

A. No, it is not. It has been over 12 years since the Company's last fully litigated base rate case. To now assume that PEF will need to return for an increase within two years is not reflective of past history or reasonable. Consequently, if the Commission determines that some level of rate case expense should be granted to PEF for recovery (which I do not recommend), the actual amount incurred should first be reduced to revise excessive billing rates, then the minimum amortization period should be set at four years.

Q. WHAT ADJUSTMENTS ARE NECESSARY TO REFLECT YOUR RECOMMENDATION THAT RATE CASE EXPENSE BE BOOKED BY PEF IN THE CURRENT PERIOD AND NOT DEFERRED FOR AMORTIZATION IN RATES?

A. Test year expenses should be reduced by $1,500,000 and rate base should be reduced by $2,250,000. The reduction to test year expenses is reflected on page 2 of Schedules C-1. My recommended reduction to rate base of $2.25 million is included in the overall Working Capital Adjustment presented by OPC Witness Hugh Larkin, Jr., on his Schedule B-2. The total adjustment to working capital, presented on Mr. Larkin's Schedule B-2, is included on page 2 of my Schedule B-1.

Uncollectible Expense

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE FILING FOR UNCOLLECTIBLE EXPENSE?

A. PEF included $6,298,000 of net write-offs based on a projected bad debt factor of 0.1743%. The Company also included the projected 0.1743% bad debt factor in determining its net operating income multiplier.

Q. IS THE 0.1743% BAD DEBT FACTOR USED BY PEF IN PROJECTING THE FUTURE RATE YEAR AMOUNT CONSISTENT WITH HISTORIC BAD DEBT RATES REALIZED BY PEF?

A. No, it is not. PEF MFR Schedule C-11 provided the bad debt factor, calculated as the net uncollectible write-offs to gross revenues from sales of electricity, for each year, 2001 through 2004. I have presented the bad debt factor and the amounts used by PEF to calculate those factors, for each year 2001 through 2004 on Schedule C-2, attached to this testimony. As shown on the schedule, the bad debt factors vary from year to year and range from a low of 0.1228% to a high of 0.1700% in 2003. Each of the annual rates are lower, some considerably so, than the 0.1743% rate projected by PEF for the 2006 projected test year.

Q. HOW DID THE COMPANY DETERMINE ITS PROJECTED TEST YEAR FACTOR OF 0.1743%?

A. There is no explanation in PEF's filing of how the factor was determined, other than on MFR Schedule C-11, which states "Bad debt projections are based on historical arrears."

The actual calculations of the projections were not provided, nor was any testimony provided describing how the amount was determined.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE PROJECTED AMOUNT OF UNCOLLECTIBLE EXPENSE AND THE PROJECTED BAD DEBT FACTOR?

A. Yes. As shown on Schedule C-2, the bad debt factor for PEF varies from year to year. I recommend that PEF's projected 2006 bad debt factor be replaced by the four-year average factor calculated using the years 2001 through 2004, resulting in a bad debt factor of 0.144%. As the level of bad debt expense to revenues varies from year to year, use of an average rate is appropriate to reflect a normalized level in rates going forward. As shown on Schedule C-2, replacing PEF's proposed 0.1743% factor with my recommended factor of 0.144% results in projected net write-offs of $5,218,000 which is a $1,080,000 reduction to the amount included in the filing. As shown on Schedule A-1, I have also replaced PEF's bad debt factor with my recommended bad debt factor for purposes of calculating the net operating income multiplier in this case.

Service Company Incentive Compensation

C. OPC WITNESS HELMUTH SCHULTZ HAS RECOMMENDED SEVERAL ADJUSTMENTS TO INCENTIVE COMPENSATION EXPENSE. ARE THERE ANY ADDITIONAL AMOUNTS INCLUDED IN THE PROJECTED TEST YEAR FOR INCENTIVE COMPENSATION BEYOND THE AMOUNTS IDENTIFIED AND ADDRESSED BY MR. SCHULTZ?

A. Yes. In addition to the incentive compensation expense addressed by OPC witness Helmuth Schultz in his direct testimony, there is $5,671,471 included in the projected test year in expense Account 920 – Salaries and Wages for incentive compensation allocated to PEF from Progress Energy Service Company. (Response to OPC Interrogatory 6, Attachment E, Bates No. PEF-RC-009797) The $5,671,471 is PEF's projected allocation in 2006 of a total amount of $14,905,313.

Q. WHAT AMOUNT IS INCLUDED IN THE HISTORIC TEST YEAR FOR ALLOCATIONS FROM PROGRESS ENERGY SERVICE COMPANY FOR INCENTIVE COMPENSATION?

A. In response to OPC Interrogatory 6, as Attachment E, the Company provided the total pool of costs being allocated by the service company, along with the respective amount allocated to PEF, by cost item, for 2004 and projected 2005 and 2006. While the allocation of service company incentives appeared in the 2006 projected test year listing, it did not appear in the actual historic test year listing.

Q. SHOULD AN ADJUSTMENT BE MADE TO THE PROJECTED TEST YEAR FOR THE INCENTIVE COMPENSATION ALLOCATED FROM PROGRESS ENERGY SERVICE COMPANY?

A. Yes. OPC witness Helmuth Schultz is recommending that the entire cost included in the projected test year for the management incentive compensation plan be removed and not recovered from ratepayers. The reasons for removal of the costs of the management incentive plan are addressed in Mr. Schultz's testimony. Consistent with Mr. Schultz's recommendation with regards to the incentive plan, I have removed the incentive compensation projected to be allocated from the service company to PEF in the projected test year of $5,671,000 on Schedule C-1, page 2.

Directors & Officers Liability Insurance Expense

Q. HOW DOES THE AMOUNT OF EXPENSE INCLUDED IN THE PROJECTED TEST YEAR FOR DIRECTORS AND OFFICERS LIABILITY INSURANCE COMPARE TO PRIOR YEARS?

A. As shown below, the expense incurred, and projected to be incurred, by PEF for Directors & Officers (D&O) liability insurance has increased significantly since 2002. Presented below are the amounts recorded in Account 925 for the expense associated with D&O liability insurance, by year:

2001	$ 244,087
2002	$ 564,835
2003	$1,046,969
2004	$1,726,822
2006	$1,952,637 (projected)

Q. WHAT FACTORS HAVE CAUSED THE SIGNIFICANT INCREASE IN D&O LIABILITY INSURANCE RATES?

A. When discussing the unfavorable benchmark variances in Account 925 – Injuries and Damages in his direct testimony, PEF witness Robert Bazemore, Jr. states that: "Executive liability insurance is unfavorable compared to the benchmark by $1.5 million due primarily to market conditions and the reaction of the Directors' and officers' liability insurance industry to corporate scandals such as Enron."

The increase addressed by Mr. Bazemore is consistent with what has happened in other utility regulatory cases in which I have participated. Large increases in D&O liability insurance premiums have been typical across the nation. Consistent with Mr. Bazemore's assertion, I agree the increases are largely attributable to the recent accounting scandals of entities such as Enron, Global Crossing and Worldcom. The fallout of mistakes and improprieties of shareholders and management of certain corporations is significantly increasing the costs to companies of D&O liability insurance.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE LEVEL OF EXPENSE INCLUDED IN THE PROJECTED TEST YEAR FOR DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A. Yes. The purpose of D&O liability insurance is to protect shareholders from their own decisions. Shareholders elect the Board of Directors who are responsible for the appointment of officers of the Company. The covered officers and directors are compensated to provide quality leadership and to serve the Company with integrity. Ratepayers do not choose who manages the Company and who serves on the Board of Directors. It is the shareholders who make the ultimate decision. Additionally, ratepayers will not be the ones compensated by insurance companies for losses incurred by shareholders for managements and directors mistakes or improprieties. As a result, shareholders should be responsible for their decisions regarding the management of the Company. The costs associated with the protection of the shareholders' investment should be born by shareholders. I have removed the projected rate year expense associated with Directors' and Officers' liability insurance of $1,953,000 on Schedule C-1, page 2. This results in a reduction to jurisdictional O&M expense of $1,805,000. Ratepayers should not be responsible for these costs.

NEIL Distributions

Q. DID MR. BAZEMORE'S TESTIMONY ADDRESS ANY ADDITIONAL FACTORS CAUSING THE PROJECTED UNFAVORABLE BENCHMARK VARIANCE IN ACCOUNT 925 – INJURIES AND DAMAGES?

A. Yes. Beginning at page 17, Mr. Bazemore indicates as follows:

> In the nuclear insurance area, nuclear property is insured through Nuclear Electric Insurance Limited ("NEIL"). NEIL is a mutual insurance company whereby the member's cost is typically reduced by distributions as a result of excellent industry performance and investment returns in underlying assets. The test year budget for nuclear insurance is unfavorable by $4 million compared to the benchmark due to a decrease in distributions from NEIL. The NEIL distributions are lower because of fluctuations in its investment market performance.

Q. WHAT AMOUNT DID PEF INCLUDE IN THE PROJECTED TEST YEAR AS AN OFFSET TO INSURANCE COSTS FOR DISTRIBUTIONS FROM NEIL?

A. The response to OPC Interrogatory No. 47, Attachment V, shows that the filing includes a projected NEIL Nuclear distribution for PEF of $2,196,000 for both 2005 and 2006.

Q. WHAT HAS BEEN THE ANNUAL LEVEL OF NEIL DISTRIBUTIONS FOR PEF IN RECENT YEARS?

A. According to the response to OPC Interrogatory No. 47, Attachment V, PEF received the following distribution amounts from NEIL:

2002	$ 4,588,929
2003	$ 2,851,622
2004	$ 2,269,447

C. DO YOU AGREE WITH PEF THAT THE NEIL DISTRIBUTION SHOULD BE REDUCED TO $2,196,000 FOR THE PROJECTED TEST YEAR?

A. No, I do not.

While the amount of distribution received from NEIL, which is an offset to the nuclear property insurance costs, did decline from 2002 through 2004, the annual distribution has since increased into 2005. In response to OPC POD 42, the Company provided copies of correspondence it has received from Nuclear Electric Insurance Limited. Included in the response was a "Schedule of Policyholders' Distribution net of 2005 Renewal Premium." The information provided indicates the NEIL nuclear distributions for PEF for 2005 is $2,834,700. This amount is $639,000 higher than the projected amount for that period included in PEF's filing. It is also higher than the 2004 level of $2.27 million and is close to the actual 2003 level. Considering the distributions have increased in 2005 as compared to the decrease predicted by PEF in its filing, I recommend that the most recent NEIL nuclear distribution amount indicated to the Company from NEIL of $2,834,700 be used as an estimate for the 2006 projected test year. This results in a $639,000 reduction to insurance expense.

C. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO INSURANCE EXPENSE FOR NUCLEAR PROPERTY INSURANCE PREMIUMS AND DISTRIBUTIONS?

A. As shown on Schedule C-1, page 2, I recommend that insurance expense be reduced by $639,000.

<u>Distribution Vegetation Management Expense</u>

Q. WHAT AMOUNT HAS THE COMPANY REQUESTED FOR DISTRIBUTION VEGETATION MANAGEMENT EXPENSE AND HOW DOES THE REQUESTED LEVEL COMPARE TO HISTORIC LEVELS?

A. PEF's adjusted projected test year includes $26,260,000 for distribution vegetation management expense. This is based on the Company's current 2006 budgeted amount of

$15.26 million, increased by $11 million for PEF's proposed incremental reliability initiative. On Schedule C-3, I provide a comparison of historic actual distribution vegetation management expense levels with the proposed level included in the projected test year. As shown on that schedule, the Company's actual expense was $9.6 and $9.5 million in 2000 and 2001, respectively. In 2002, the expense increased to $13.2 million and was $15.41 million in the 2004 historic test year. The Company's requested expense level of $26.26 million is significantly higher than the historic cost level and is considerably higher than the amount budgeted by the Company in 2006 as part of its normal budgeting process. As shown on Schedule C-3, the proposed level is over 70% higher than the actual historic test year level.

Q. DID PEF SUBMIT TESTIMONY ADDRESSING THE PURPOSE OF THIS REQUESTED 70% INCREASE IN COSTS?

A. Yes. PEF witness David McDonald addresses this increase in very broad terms in his direct testimony. His testimony indicates, beginning at page 3, that the Company is "...proposing twelve specific incremental distribution reliability initiatives representing $17.3 million in capital, $18.7 million in O&M in our 2006 test year that will accelerate or go beyond existing levels of activity." Included in the $18.7 million of incremental O&M reliability initiatives is the $11 million increase for distribution vegetation management. His testimony and exhibits do not address how the $11 million increase was determined, what impact on reliability the additional $11 million is projected to have, or how the Company feasibly can plan to ramp up its distribution vegetation management by over 70% in a one-year period to reach its proposed resulting cost level of $26.26 million.

Q. DID YOU RECEIVE ANY ADDITIONAL INFORMATION REGARDING THE DETERMINATION OF THE ADDITIONAL $11 MILLION FOR THE VEGETATION MANAGEMENT RELIABILITY INITIATIVE?

A. Yes. In response to OPC Interrogatory No. 73, the Company provided some additional detail at a summary level regarding how the $11 million of incremental costs beyond the $15.26 million already included in the 2006 budget was determined. According to the response, the costs include an additional 3,207 miles to be trimmed. According to the response to OPC Interrogatory 110, 4,000 distribution miles were trimmed in 2004 and 2006 was projected at 4,350 miles. Adding the incremental miles to be trimmed under the initiative of 3,207 miles to the projected miles to be trimmed of 4,350, results in 7,557 miles of tree trimming that is apparently included in the Company's request. According to OPC Interrogatory 110, the total projected above ground distribution miles for 2006 is 18,271 miles. This would result in the Company's projections, inclusive of the incremental expenditures, being 41% of the distribution miles being trimmed in 2006.

According to PEF's response to OPC Interrogatory No. 109, the Company's goal under its vegetation management program is to inspect and prune the system on a three-year goal cycle.

Q. HAS THE COMPANY'S FILING DEMONSTRATED THAT A 70% INCREASE IN DISTRIBUTION VEGETATION MANAGEMENT SPENDING IS NECESSARY?

A. No, it has not. PEF witness David McDonald indicates at page 4 of his testimony that PEF's System Average Interruption Duration Index ("SAIDI") has improved from a 2000 level of 100.6 minutes to a 2004 level of 77 minutes, a 23% reduction. As indicated previously in this testimony, the distribution vegetation management expense for PEF increased from $9.5 million in 2002 to $15.41 million in 2004. His testimony indicates that the 2004 SAIDI performance is in the top-quartile performance among the Company's peers. Mr. McDonald also state that the Customer Average Interruption Duration Index ("CAIDI") and the Customers Experiencing Multiple Interruptions ("CEMI") have declined. Given this information, the Company has not demonstrated that an additional 70% increase above the 2004 level is necessary or cost-effective.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARDS TO THE DISTRIBUTION VEGETATION MANAGEMENT EXPENSE?

A. I recommend that the actual 2004 distribution vegetation management expense level of $15.41 million, which is close to the amount PEF has included in its budget for 2005 and 2006, be increased by a maximum of 50%. This would result in a projected test year expense of $23.1 million, which is $3,145,000 less than the amount included by PEF in its filing. The necessary adjustment is shown on Schedule C-3. My recommended level would still allow for a significant increase in vegetation management expenditures that should result in additional improvements in reliability. Additionally, the OPC has not adjusted any of the remaining distribution reliability initiatives included in PEF's filing.

In addition to allowing for the 50% increase beyond the 2004 actual expenditures, I recommend that PEF be required to report to the Commission on a regular basis, such a quarterly, on the actual distribution vegetation management expenditures. In the event PEF does not actually spend the amount it receives in rates for vegetation management costs, I recommend that the amount under-spent be deferred and returned to ratepayers. Considering the substantial projected increase coupled with the lack of supporting detail, such a deferral would be appropriate in this instance.

Property Tax Expense

C. ARE YOU RECOMMENDING ANY REVISIONS TO THE COMPANY'S PROPOSED PROPERTY TAX EXPENSE?

A. Yes, I am recommending several modifications to PEF's property tax calculations. PEF provided its calculation of projected property tax expense, totaling $101,229,000, in response to OPC Interrogatory No. 53. In projecting the 2006 property tax expense, the Company applied an assessed value factor to its projected net taxable plant balance as of December 31, 2005. It then applied its estimated effective millage rate to the projected assessed value to determine its projected property tax expense. Citizens' witness Hugh Larkin, Jr. has recommended several adjustments that impact the Company's projected net taxable plant balances as of December 31, 2005. On Schedule C-4, I have adjusted property tax expense to reflect the impact of Mr. Larkin's recommended adjustments to projected plant in service, plant held for future use and materials & supplies.

Q. ARE THERE ANY ADDITIONAL ADJUSTMENTS YOU ARE MAKING TO PEF'S PROPERTY TAX EXPENSE CALCULATIONS?

A. Yes. I have also reduced the net taxable plant balance at December 31, 2005 by $23,361,000 to remove the impact of an above market affiliate transfer. On MFR Schedule B-1 for the projected test year, the Company removed $23,371,000 from plant in service in order to remove the amount above market value associated with an asset transferred from an affiliated company. According to the response to OPC Interrogatory No. 226, the amount of affiliate transfer above the market value of the asset transferred was included in Account 114 – Electric Plant Acquisition Adjustments. Electric Plant Acquisition Adjustments are included in the net taxable plant upon which the property tax expense is calculated. While the Company did remove the above market value of the asset transfer from plant in service on MFR Schedule B-1, it did not remove the amount in determining its projected property tax expense. Consequently, on Schedule C-4, I remove the amount included in PEF's projected property tax expense associated with the above market transfer of assets from the affiliated entity.

Q. WHAT IS THE IMPACT OF YOUR REVISIONS TO PEF'S PROPERTY TAX EXPENSE CALCULATION?

A. As shown on my Exhibit__(DD-1), Schedule C-4, property tax expense should be reduced by $4,198,000 ($3,888,000 jurisdictional).

Impact of Adjustments to Plant in Service on Depreciation

Q. CITIZENS WITNESS HUGH LARKIN, JR. IS RECOMMENDING AN ADJUSTMENT TO PEF'S PROJECTED TEST YEAR PLANT IN SERVICE BALANCES. SHOULD AN ADJUSTMENT BE MADE TO REFLECT THE IMPACT OF HIS REDUCTIONS TO PROJECTED PLANT IN SERVICE ON THE DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION FOR THE PROJECTED TEST YEAR?

A. Yes. On Schedule C-5, I calculate the impact of the adjustment to plant in service sponsored by Mr. Larkin on depreciation expense and accumulated depreciation contained in the projected test year based on the overall composite depreciation rate of 3.54%. The composite depreciation rate was provided in the Company's depreciation study on PEF Exhibit No. __(RHB-7), volume 1 of 3, at page 1-13. Since OPC witness Jacob Pous is not recommending any revisions to the depreciation rates themselves, I utilized the composite depreciation rate proposed by PEF. As shown on Schedule C-5, the result is a $4,945,000 reduction to projected test year depreciation expense and a $2,473,000 reduction to accumulated depreciation.

<u>Income Tax Expense</u>

Q. HAVE YOU ADJUSTED INCOME TAX EXPENSE TO REFLECT THE IMPACT OF THE ADJUSTMENTS SPONSORED BY CITIZENS WITNESSES TO NET OPERATING INCOME?

A. Yes. On Schedule C-6, I calculate the impact on income tax expense, including both federal and state, resulting from the recommended adjustments to revenues and operating expenses. The result is carried forward to the Net Operating Income Summary on Schedule C-1, page 2.

<u>Interest Synchronization</u>

Q. WHAT IS THE PURPOSE OF YOUR INTEREST SYNCHRONIZATION ADJUSTMENT ON SCHEDULE C-7?

A. The interest synchronization adjustment synchronizes the adjusted rate base and cost of capital with the income tax calculation. On MFR Schedule C-2, PEF included an adjustment to synchronize its proposed rate base and cost of debt with the interest expense included in its income tax expense calculation.

Citizens' proposed rate base and weighted cost of debt differ from the Company's proposed amounts. Thus, our recommended interest deduction for determining rate year income tax expense will differ from the interest deduction used by PEF in its filing. Schedule C-7 shows the calculation of the impact on income tax expense which would be experienced as a result of the interest deduction being higher for tax purposes based on Citizens proposed rate base and weighted cost of debt.

<u>Separation of Winter Park System</u>

C. ARE YOU AWARE OF ANY CHANGES IN THE COMPANY'S SYSTEM AND CUSTOMER BASE THAT HAS NOT BEEN FACTORED INTO THE COMPANY'S FILING IN THE FUTURE TEST YEAR?

A. Yes. The Company's franchise agreement with the City of Winter Park expired, and the City of Winter Park pursued the purchase of the electric distribution system from the Company. On June 1, 2005, PEF finalized the sale of the electric distribution system within the City of Winter Park. Operational control of the distribution system was transferred to the City of Winter Park on that day. None of the impacts of this system sale by PEF and discontinuation of operating the distribution system within the City of Winter Park are included in the Company's filing.

Q. WHY WERE THE IMPACTS OF THE SALE OF UTILITY ASSETS AND TRANSFER OF OPERATIONAL CONTROL OF THE DISTRIBUTION SYSTEM NOT INCLUDED WITHIN THE COMPANY'S FILING?

A. In response to Citizens Interrogatory No. 43, PEF stated: "The impact from the sale of utility assets to Winter Park was not included in the filing because the date on which the purchase would be consummated and operational control would be transferred had not been established at the time of the filing, and that date still has not been established with certainty at the time of providing this answer."

Q. DID YOU ATTEMPT TO OBTAIN THE INFORMATION NECESSARY FROM PEF TO DETERMINE THE VARIOUS IMPACTS ON THE FUTURE TEST YEAR IN THIS CASE RESULTING FROM THE SALE OF THE ASSETS AND THE DISCONTINUATION OF THE PROVISION OF DISTRIBUTION SERVICE WITHIN THE CITY OF WINTER PARK?

A. Yes. Several interrogatories were filed by the OPC in this area in order to obtain information relevant to the impact on the 2006 projected test year and on the specific amounts contained within PEF's filing. The interrogatories requested that if actual amounts were not yet known, that the Company's then current best estimates be provided. However, the requested information was not provided.

In OPC Interrogatory No. 55, the Company was asked to provide detailed calculations of the actual, or if actual not known, the estimated gain or loss resulting from the sale of utility assets to the City of Winter Park. The Company responded stating, in part, that: "Because the closing has not occurred with the City of Winter Park, the actual or even estimated actual gain or loss resulting from the sale of utility assets to the City of Winter Park cannot be determined. The final categories of utility assets and the amounts of those assets to be transferred to the City of Winter Park will not be fully known until the transfer takes place and the closing has occurred." While the amounts may not have been fully known at that time, the Company, at a minimum, should have estimated the impacts of the sale of the assets and the impacts of the discontinuation of operational control.

C. AFTER RECEIVING THE ABOVE RESPONSE, DID YOU ATTEMPT TO OBTAIN ADDITIONAL INFORMATION ON THIS ISSUE?

A. Yes. In response to OPC Interrogatory No. 236, PEF indicated that the sale of the electric distribution system within the City of Winter Park had been finalized on June 1, 2005 and that operational control of the system was transferred to the City of Winter Park on that same day.

Q. SINCE THE SALE HAS NOW BEEN FINALIZED AND OPERATIONAL CONTROL TRANSFERRED, HAS THE COMPANY PROVIDED THE ESTIMATED IMPACTS ON ITS FILING RESULTING FROM THE SALE AND TRANSFER OF CONTROL?

A. No, it has not. On June 23, 2005, which is after the sale had been finalized and after operational control had been transferred to the City of Winter Park, the OPC submitted its Seventh Set of Interrogatories to PEF. Several questions within that set specifically pertained to this issue. Relevant interrogatories and the responses by PEF are as follows:

> 236. Franchise Agreements. Refer to the Company's response to Citizens Interrogatory No. 43. Please provide the Company's current best estimates of the total impact on the filing for the 2006 projected rate year that will result from the consummation of the sale and the transfer of operational control to Winter Park. The response should provide estimated impacts on each of the MFR schedules that will be impacted by item and account (i.e. impacts on plant in service, accumulated depreciation, depreciation expense, revenues customer #s, Kwh sales, revenues by class, property tax expense, gain(loss) on sales of property, etc.). Also include the overall impact on the projected 2006 base revenue requirement included in the Company's filing. Describe all assumptions used in preparing this response. If it is not anticipated that the transfer will be in effect for a full year in 2006, also provide the annualized impact of the sale and transfer.
>
> <u>Answer</u>
>
> The impact on the filing for the 2006 test year as a result of the separation of Winter Park from the Company's retail system has not been quantified as the Company has not yet completed all the financial transactions necessary to record the separation.
>
> ...
>
> 236. Sale of Utility Assets. Refer to the response to Citizen's Interrogatory 55. Please provide the current best estimate of the Company gain or loss resulting from the sale of utility assets to the City of Winter Park.
>
> <u>Answer</u>

> The gain or loss resulting from the sale of the electric distribution system within the city limits of Winter Park to the City of Winter Park has not been quantified as the Company has not yet completed all of the financial transactions necessary to record the separation.

Even though the sale and transfer has been complete for over a month, PEF still has not provided the best estimates of the impacts on its filing.

Q. DOES IT SEEM LIKELY TO YOU THAT THE COMPANY HAS NOT EVEN ESTIMATED THE IMPACTS OF THE TRANSACTION WITH THE CITY OF WINTER PARK?

A. I find it extremely hard to believe that the Company has not yet even estimated the impact on its operations, revenues and costs caused by this large transaction. It is also hard to believe that the Company has not yet estimated the amount of gain it will realize on the sale of the distribution system assets. The sale of the assets and the transfer of operational control of the system to the City of Winter Park were the result of Arbitration between the City of Winter Park and the Company. In response to OPC POD No. 53, the Company provided a copy of the Corrected Arbitration Award. The Corrected Arbitration Award, dated July 2003, determined that the fair market value of the electrical distribution system within the City of Winter Park was $31,350,000. The amount included assets and a "going concern" value. The Award also indicated that the Company would charge the City of Winter Park for the separation and re-integration costs and allowed for $10,737,000 of stranded costs to the Company for the period 2004 through 2010, reduced for each year in which the Company continued to serve the City of Winter Park citizens. Given that the Corrected Arbitration Award has been in place for some time, and the fact that the Company should have the information within its books and records to determine the net book value of the assets, the Company should have the information in its custody and control to determine a reasonable estimate of the gain on sale resulting from the now completed sale of the distribution assets to the City of Winter Park. It also seems logical that prior to proceeding to the Arbitration phase, throughout the arbitration process, and subsequent, the Company would have been projecting the impact of the potential loss of the distribution system and discontinuation of providing electric distribution service to the citizens of Winter Park for its own planning purposes.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE PROJECTED TEST YEAR AT THIS TIME FOR THE IMPACTS OF THE SALE OF THE ELECTRIC DISTRIBUTION SYSTEM WITHIN THE CITY OF WINTER PARK AND THE DISCONTINUATION OF OPERATING THAT DISTRIBUTION SYSTEM?

A. As the Company has not provided even the estimates of the impacts we have requested, I am unable to quantify the numerous impacts on the Company's filing. I am also unable to calculate the adjustment necessary to flow the gain on the sale of the assets to the remaining ratepayers on PEF's system. The information needed to calculate a reasonable estimate of the numerous impacts is in the Company's possession, custody and control. I recommend that the Commission require the Company to provide the calculated gain on sale resulting from the sale of the electric distribution system within Winter Park to the City of Winter Park, along with the supporting documents and calculations used in determining the gain. Once the calculations of the gain have been reviewed and verified, the Commission should then flow the gain on sale to PEF's remaining customers over a five-year period, consistent with the typical treatment of gain on sale of assets.

It should also be noted that the City of Winter Park has a contract with Progress Energy Florida for bulk power supply. Thus, the City of Winter Park will remain a customer of

PEF for at least the next several years. This means that the wholesale allocation of all plant cost and O&M expenses should be changed to reflect the fact that the City of Winter park is a wholesale customer. Also, distribution O&M expenses should be decreased since the City of Winter Park is now maintaining that part of its distribution system.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

DIRECT TESTIMONY OF PHILIP K. PORTER, PH.D.
ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP
DOCKET NO. 050078-EI
JULY 13, 2005

Q: **Please state your name, address and occupation.**

A: My name is Philip K. Porter. My business address is Department of Economics, University of South Florida, Tampa, FL. I am Professor of Economics and Director of the Center for Economic Policy Analysis. A summary of my research interests and curriculum vitae are attached as Exhibit No. ___ (PKP-1), Appendix A.

Q: **What is the purpose of your testimony in this proceeding?**

A: I have been asked by the Florida Industrial Power Users Group (FIPUG) to provide testimony regarding past and present financial market conditions as they pertain to Progress Energy Florida (PEF) and to evaluate the testimony of Dr. James H. Vander Weide and Dr. Charles J. Cicchetti in this proceeding.

Q: **Please summarize your findings.**

A: In today's financial marketplace investors in large, joint-stock companies (ones with capitalization in excess of $5 billion) must anticipate a company's equity will yield between nine-percent and ten-percent annually to induce investment and to retain shareholders. Investors in utilities will require a lower expected return. Dr. Vander Weide's assessment that the market requires 12.3 percent allowed return on equity to induce investment in PEF is excessive. Dr. Vander Weide makes incorrect and inappropriate assumptions in the application of the capital asset pricing model and the discounted cash flow model to arrive at his conclusion. Dr. Cicchetti's idea that a bonus of 50 basis points as a reward for past performance is warranted and will inure to the future benefit of PEF's customers is without foundation and, almost certainly will not benefit electricity consumers. To put the assumptions and findings of Drs. Vander Weide and Cicchetti in perspective I present a reality check based on the expected returns for a competitive enterprise of similar size. The current expected market return for competitive companies is less than 10 percent. When this return is compared to the return required for a less risky regulated utility I find that an appropriate return on equity for PEF is less than 9 percent, 400 basis points less than the company seeks. Based on common equity of $2.55 billion and a tax markup factor of 1.632 this reduces the company's revenue request by $166.6 million per year.

Q: With respect to Dr. Vander Weide's analysis, what factors led to the excessive estimate?

A: Specifically, Dr. Vander Weide assumes an equity risk premium that is too high, a market beta that is too high, an expected growth rate for equity returns that is too high, and an expected yield on A-rated utility bonds that is too high. In addition, he adds an adjustment for flotation without justification and fails to account for the favorable treatment of regulated utilities in the financial markets. The combination of these factors yields an estimate that overstates the required return by more than 33 percent.

Q: How can Dr. Vander Weide be so wrong?

A: Application of the discounted cash flow model (DCF) and the capital asset pricing model (CAPM) require great care lest error, bias, or manipulation render the application invalid. These models share two latent flaws that make careful study and control of the application necessary before information useful in a regulatory proceeding is ascertained. First, neither of these models is particularly accurate and each is subject to manipulation by anyone with a bias. Estimation of the parameters in each of these models is notoriously inaccurate. Precision is often so weak that little confidence can be placed in the point estimates used. Parameter estimates vary widely from one sample to the next. To make this problem worse each of these models is interactive; one parameter estimate is multiplied or divided by another. This compounds the error, increasing it geometrically. For example, in the CAPM model the adjustment for systematic risk is beta times the risk premium. If the estimate of beta is 50 percent too high and the estimate of the risk premium is 50 percent too high, the model overestimates the risk adjustment, not by 100 percent, but by 125 percent.

Second, the models are complex and not easily understood. This gives the estimation process the appearance of a scientific inquiry, but, because of the inherent inaccuracy, defies a basic axiom of scientific modeling, which is to avoid assumptions that increase complexity without increasing accuracy. What complexity does is increase opportunities for error in the model's use. This happens because at each step in the model's implementation a new parameter is estimated or chosen. The more steps in the implementation of a model, the more opportunities there are for error and implausible conclusions. These models come with a powerful accumulation of error and bias that, because of their complexity, the layperson is not equipped to critique. At this level of abstraction a reality check is needed. Recalling fundamental truths about capital markets will help identify the more egregious errors in the use of the models.

Q: Are the reports of the experts biased?

A: One would hope not, but with so much at stake bias is inevitable. I have reviewed the various methods used in this, and in other, rate proceedings. It is my conclusion that there is more than ample latitude in the measurement of the parameters of the models and in the applications of the models to make it possible to come to virtually any finding one might wish. It is not uncommon for the expert witnesses for the utility and those for the various consumer groups to put forth estimates that differ by 400 or 500 basis points. Such differences may occur naturally without deliberate manipulation of a model. However, were there no bias in the selection and presentation of the experts by interested parties, differences of opinion would be randomly distributed so that half the time a rate case is called the expert for the consumer group would identify a fair rate of return higher than that identified by the expert for the utility and the case would immediately settle to everyone's liking. Instead, in virtually 100-percent of the rate cases, the experts hired by consumer groups opine on a fair rate of return that is lower than that offered by the experts hired by the utility, in spite of the fact that they use essentially the same models.

Q: Is the true cost of equity likely to be somewhere in between the estimates of the various experts?

A: Yes, but the difficult question is where. Knowing that each side in an adversarial proceeding presents its best case doesn't help much if the magnitude of exaggeration is unknown. For example, if we know that everyone exaggerates to the same degree, the Commission could split the difference and come close to the true figure. However, in this type of proceeding there is an obvious lower bound to the cost of equity capital, but no apparent upper bound. We know the expected return on equity cannot be less than the bond rate paid by the firm, which is easy to observe. On the upper end, the sky appears to be the limit. Without an upper bound, splitting the difference always favors the utility.

Q: Briefly describe the models.

A: **The Discounted Cash Flow Model:** In the DCF model the basic estimating equation for the equity cost of capital is

$$k = \frac{CF}{PV} + g$$

where k is the cost of capital, CF is the expected dividend or cash flow to be earned by shareholders in the next period, PV is the present market value of the company, and g is the anticipated growth rate of earnings (dividends and asset appreciation).

The original work by J. Williams was published in 1938[1] as a treatise on what determines value for investors. Williams noted that present value is the discounted stream of future cash flows as given by the following equation:

$$PV = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_T}{(1+k)^T}$$

In this well-respected formulation investors are assumed to have some information that leads them to believe a particular company will yield cash flows to the investor in each of T future time periods. The value of k is the investor's personal discount rate. This is a theory about how investors measure value and is dependent only on the investor's perceptions.

[1] Williams, J.B., *The Theory of Investment Value*, Harvard University Press, Cambridge, Mass., 1938.

To transform this into a cost of capital model several assumptions are made. First, it is noted that investors sell the asset if their present value calculation is less than the market price, driving the price down, and buy the asset if it is greater, driving the price up. Arbitrage thus equates the investor's present value of cash flow with the capital market's valuation of the firm. The same assumption is applied to the investor's discount rate. When investors hold discount rates that are greater than the market rate, they borrow and drive market rates up. When the opposite is true they lend and drive market rates down. Arbitrage thus equates the market cost of capital with the average individual discount rate. Second, it is assumed that the asset yields a cash flow into the indefinite future, and that the rate of growth in the cash flow is constant. That is, $CF_{t+1} = CF_t(1+g)$ for every period t. The model can be more complex, permitting differential growth rates and definite horizons, but these assumptions permit the simple solution for k given by $k = \frac{CF}{PV} + g$.

In this formulation, the cost of equity (formerly the investor's personal discount rate) is to be determined by expectations of future cash flows and of the growth of such flows. Whereas the first formulation by Williams was a personal valuation determined by personal beliefs, this is a market valuation determined by personal beliefs. Since CF and g are both investor expectations they cannot be accurately measured. In fact, no accepted methodology for measuring expectations exists and the expert, in applying this method, is left with a grab bag of possible ways to make such estimates.

The Capital Asset Pricing Model: In the CAPM model the basic estimating equation for the equity cost of capital is

$$k = r_f + \beta \times ERP$$

where r_f is the expected return on a risk free asset, β is the beta for the company, and *ERP* is the expected equity risk premium. This formulation adjusts the cost of equity for a specific firm for systematic risks in the market. Theoretically, unsystematic risk is eliminated by diversification of one's portfolio.

Systematic risk is risk that affects all stocks and typically stems from macroeconomic shocks, like changes in government borrowing or Federal Reserve activity, or from global influences, like energy price shocks. One cannot diversify against this risk, but noticeably it affects some stocks more than others. Beta measures the change in the excess yield on the stock in question as a fraction of the change in the excess yield on all equities. The excess yield is the market yield less the yield that is appropriate for the particular asset given its unsystematic risk. Low values of beta imply that the company's return is not particularly prone to systematic risk. A beta of one means the company's return on equity moves exactly with changes in returns on the market, and a beta greater than one implies this company's return is more volatile than the market. With less systematic volatility the asset is more secure (less risky) than the market as a whole and therefore requires a lower return on equity. With high systematic volatility the opposite is true. Beta is typically measured as the slope of the regression line that fits changes in the firm's equity return to changes in the market's return on a benchmark asset.

The expected equity risk premium is the amount by which investors expect the future return on equities to exceed the return on a risk-free asset. *ERP* is typically measured by the average annual difference in the equity market return for some benchmark portfolio and the risk free asset as calculated over some period.

To apply this formula one must first know the company's beta. This is difficult to ascertain and any estimate is subject to huge error. The vast majority of the regression models that estimate beta explain less than 30 percent of the variation in an asset's yield and the estimated betas are often not significantly different than zero. This means that when one applies the beta to determine k in the model, more than two-thirds of what actually determines variations in the equity yield is missing from the model and, further, that the user cannot say with any meaningful level of confidence that there is *any* equity premium to be applied for the firm in question. The problem is compounded by the fact that there is a different beta estimate for every historical set of data and for every benchmark portfolio (market proxy), and because of anomalies in the empirical results, a host of corrections that can, or cannot, be applied.

The following is a list of betas, all applying one or another of a host of adjustments:

- Blume adjusted beta
- Betas for different market proxies
- Levered beta
- Unlevered beta
- Full information beta
- Sum beta
- Vasicek adjusted beta

In addition to betas of each type, these betas differ depending on the time period over which data for the application is chosen. Because the regression fit is so poor these betas can change drastically from one period to the next. Finally, there is a host of commercial sources for beta, including Bloomberg, Compustat, Ibbotson, and Value Line. Exhibit No. ___ (PKP-2), Appendix B shows beta estimates for the same company provided by different companies at the same time and estimates of beta by the same estimator over time.

The second step in the CAPM estimation is to estimate *ERP*, the expected equity risk premium. This is usually the average annual return on some benchmark portfolio, like the S&P500, minus the average annual return on the risk-free asset calculated over an historic period. There are two measures of the average annual return, the geometric average and the arithmetic average. Apparently there is some confusion about which is appropriate. The appropriate measure for the average yield over an historical period is the geometric average.[2] Nonetheless, failing to understand this allows the expert to choose among alternatives.

A second consideration is the time period chosen for analysis. Ibbotson Associates publishes its Valuation Edition each year that contains annual data from 1926. To make high estimates one might use the last 15 years beginning with 1991. To make low estimates one might use the last five years beginning with 2001. It is traditional to use a longer data set. Using all the data avoids the perception of choosing a special data set, but includes the unusual periods of the Great Depression and World War II. Using the past 50 years might be more appropriate, although any differences that work to the perceived advantage of the expert should raise suspicions of bias.

Q: Are there other models that might be used?

[2] See Appendix C for a discussion of the appropriateness of the geometric mean.

A: Yes. The buildup model is a simple additive model. It breaks the cost of equity into component parts, estimates each of these parts and sums them. A depiction of the model is:

	Risk-free rate
+	Equity risk premium
+	Firm size premium
+	Industry premium
=	Cost of equity

The risk-free rate and the equity rate premium are as discussed above. The firm size premium typically is measured as the long-term return on common equity stocks for firms of a given size minus the same period return for large firms. Size classifications range from micro-capitalization (capitalization less than about $200 million) to large capitalization firms (capitalization more than $5.0 billion). Large-cap firms are defined either as the S&P500, or as firms in the highest 20% of capitalization (NYSE1-2). As PEF is a large-cap stock, size adjustments are not needed.

The industry premium reflects the difference in the return on equities for firms in different industries. For utilities the industry risk premium is negative reflecting the fact that investments in utilities are less risky than investments in other assets. Appraisers typically make qualitative judgments about an industry and adjust their cost of equity accordingly. Because the estimate of the industry premium is subjective, it should be carefully evaluated. Ibbotson Associates attempt to calculate industry premia in an objective way. However, their calculation relies on an estimate of beta and therefore suffers from a lack of precision. For SIC classification 49: Electric, Gas, and Sanitary Services the industry premia calculated through the end of 2001 is –6.92.[3] This is

[3] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation: Valuation Yearbook 2003, p. 46.*

probably too great, as its use would eliminate most of the equity risk premia. It does, however, indicate that on average the utilities need not pay as high a return on equity as other industries to attract capital.

While each component of the buildup model is subject to measurement error and manipulation, one advantage is that the errors created in this way are only added together. That is, total distortion is the sum of the distorted parts. In the CAPM and DCF models, where component parts are multiplied, errors in each measure are compounded. A second advantage is the transparency of the model, it is easy to understand and therefore more difficult to manipulate. A very simple version of the buildup model provides a reality check on the estimates from the other models.

Q: Please describe how you use the buildup model as a reality check.

A: Before any expert witness testimony is introduced and considered by the Public Service Commission in a rate case it should be vetted for obvious distortion. That is, there should be a sort of smell test. Testimony that challenges the olfactory glands should be ignored. In this case there are obvious upper and lower bounds to what is a fair rate of return on equity and testimony that falls outside these bounds can safely be ignored. To establish such boundaries we must rely only on easily observed data points that were created, without bias, and independent of this procedure and use transparent modeling so that the data and the application can be easily scrutinized.

I consider the following observations to be unbiased and their origin to be independent of this procedure:

1. As far as we are concerned, the future is unknown. The best we can do is make informed guesses about what will be.
2. To be attractive to investors, expected yields on equity must be greater than the observed yield on secure assets. Furthermore, to attract equity capital to any given company, the expected yield on equity must be greater than the existing bond yield for the firm.
3. As of July 1, 2005 the six-month U.S. Treasury Bond yield is 3.37 percent.[4]
4. As of July 1, 2005 Progress Energy sold short-term bonds (eight months to maturity) with an annual yield of 4.002 percent[5] and 30-year A-rated utility bonds were selling that yield 5.0 percent.[6]
5. Companies that are perceived as less risky attract equity investors with lower equity yields than companies that are perceived as more risky.
6. Because of their size (and the attendant longevity), large companies are perceived as less risky than smaller companies and, therefore, can attract equity investors with a lower expected return.
7. Regulated utilities are perceived as less risky than proprietary firms.
8. Progress Energy Florida is a large, regulated utility.

These observations describe the world at the time of observation. Predictions about the future require some method and presumably are based on experience. Exhibit No. ___ (PKP-4), Appendix D presents historic observations on the yields of various assets as presented in Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation: Valuation Yearbook 2004*. I believe every expert in this proceeding uses this data and I submit it as

[4] This quote was from SmartMoney.com as of 5:00 p.m. EST.
[5] This observation was provided by InvestinginBonds.com
[6] Quote from PiperJaffray online.

unbiased data set. Table D1 presents the annual yield on large capitalized firms and U.S. Treasury Bills for the past 50 years. I chose 50 years (rather than the more extended data set beginning in 1926 from which this data was drawn) to avoid distortions caused by the extraordinary events of the Great Depression and World War II. Summary data from the series beginning in 1926 are also presented.

For the past 50 years large–cap stocks have generated an average annual yield of 10.94 percent. Over the same period short-term U.S. Treasury bills generated an average annual return of 5.28 percent. The average return annual return on large-cap stocks for the past 50 years has averaged 5.66 percentage points more than the average yield on short-term U.S. Treasury bills. For the 79-year period this premium averaged 6.70 percentage points. Including the period of the Great Depression and WWII in the data accounts for the increase in the calculated equity risk premium. Including the devastating stock consequences of the Great Depression lowers the equity return by 0.5 percentage points. The big effect is on the average return on Treasury bills. From 1931 to 1955 the average Treasury bills returned only 0.6%. Such extraordinary times have never been repeated.

We can use the buildup method to create a reality check with only one assumption. Namely, that the premium equity investors demand before they will invest in large-cap stocks is equal to the average premium for the past 50 years. That is, on July 1, 2005 a typical large-cap firm could sell equity if consumers expected the asset to yield

	3.37%	The July 1, 2005 six-month U.S. Treasury bond yield.
+	5.66%	The historical equity risk premia for large-cap stocks.
=	9.03%	

If equity investors require the higher annual equity premia for the 79-year data set, a prospective equity investor would require a yield of 10.07% to induce him or her to invest. Any estimate of the fair rate of return on investment for PEF that exceeds 9.03% begins to smell. Any estimate greater than 10.07% should be rejected out of hand as being totally unreasonable.

Finally, there is also a lower bound on the equity cost of capital given by the yield on Progress Energy's short-term bond issues. No estimate of the cost of equity capital below 4.0 percent or above 10.0% should be given much credence.

Q: Is there any way to corroborate this?

A: Yes. Economics tells us that the value of an asset is the discounted present value of the stream of income it provides. If investors expect to earn a stream of $\$Y$ per year from an investment that extend indefinitely into the future and can earn a return of r from the stock market with the same level of risk, that asset's present value or worth is

$$PV = \frac{\$Y}{r}.$$

For a regulated utility the stream of annual equity earnings is the allowed return on equity times the rate base:

$$\$Y = r_r RB$$

Substituting for \$Y and rearranging terms this gives us a simple test. Note that

$$\frac{PV}{RB} = \frac{r_r}{r}.$$

That is, the market value of the regulated firm relative to its rate base is equal to the regulated return on equity relative to the required return on equity.

Compustat publishes market value to book ratios for all publicly traded companies. For the parent company, Progress Energy, this value is $PV/RB = 1.37$. If this value holds for PEF it means the present regulated return on equity is 37 percent higher than that needed to reward equity investors for their contributions to the historic cost of the firm. The present regulated return of 12.0% should be reduced to 8.8%.

There is other evidence that support this conclusion. In 1992 the yield on 10-year Treasury securities averaged 7.01 percent. In 2005 these same securities had an average yield of 4.23 percent.[7] The yield on the risk-free asset that forms the basis of Dr. Vander Weide's CAPM analysis has fallen 278 basis points. Adjusting the regulated rate of 12.0 percent for this decrease to be consistent with past findings by the Commission yields a rate of 9.22 percent. Finally, The Social Security Administration has determined that a real interest yield of 7.0 percent on stock market investments should be used to analyze proposals to privatize Social Security. Consensus forecasts of inflation conducted by the Bureau of Economic Research of the Federal Reserve Bank of Philadelphia during the second quarter of 2005 put expected inflation at 2.5 percent.[8] This yields a return on all stocks of 9.5 percent. Those who argue against privatizing Social Security say this is too high.

Q: You present 10 percent as an upper bound. Why is that?

A: The 10 percent upper bound is what equity investors who recall the 1930s and 1940s and give these times equal weight in their assessment of an equity risk premium would require to make investments in large-cap stocks. Investors who discount the 1930s

[7] Published by the U.S. Federal Reserve System at http://www.federalreserve.gov/releases/h15/data/b/tcm10y.txt

[8] www.phil.frb.org/files/spf/survq205.html

and 1940s would require less. In addition, this is a publicly regulated utility with considerably less risk than the typical large-cap stock.

Q: Are there other adjustments that should be applied to the reality check model?

A: The fundamental thing we want to do with the reality check model is rule out bad estimates. This is purposefully done in a simple and understandable way so there can be no slight of hand. Adjustments defeat this purpose.

However, if past flotation costs have not been recovered and it is determined that the appropriate way to recover them is through an adjustment to the equity rate of return, some adjustment must be made. In addition, while I hesitate to make a utility industry adjustment I have considered it when I state that 10% is the upper bound for the cost of capital.

Q: What adjustment would be appropriate for a utility?

A: Exhibit No. ___ (PKP-5), Appendix E presents a discussion of company-specific risk of a regulated utility and evidence of the historical treatment of investments in utilities relative to the benchmark S&P500. In general, a regulated utility, and PEF in particular, faces little of the risk that proprietary firms face. First, most of the highly volatile cost changes that equity owners in proprietary firms must absorb are estimated by the Commission and immediately passed through to consumers. Any shortfall is made up with interest. Because the demand for electricity is inelastic, this pass through has little effect on sales and therefore insulates investors. In competitive markets, rising fuel prices, the cost of government mandates, and weather related costs that affect one firm could not be passed along to consumers in the form of higher prices, putting investors at greater risk than if they had invested in a utility.

Second, private firms face risk from demand fluctuations that stem from two sources: changes in the demand for the product of the firm and changes in the market share of competitors. The demand for electricity is little affected by time (except that individual demand is steadily growing) and utilities have a guaranteed market. While there may be some adjustment in demand by industrial customers or in states where there is a declining population base, PEF benefits from a steadily increasing customer base of predominately residential consumers.

Finally, Florida utilities face little financial risk. Rate relief can immediately address equity returns that fall below the lower bound of the accepted range, even if the source of the poor performance is the utility's mistake. When interest rates in the economy are rising, regulators raise rates and allow the utility to earn higher returns. When interest rates are falling, as they have over the past decade, the utility returns above average yields.

Historically, investors in utilities have been content with a return on equity that is 65 to 120 basis points less than the return on the S&P500.

Q: What adjustment is appropriate for flotation costs?

A: Flotation costs may be expensed, added to rate base, or paid for by increasing the required return on equity. We know that past flotation has not been included in rate base. If flotation costs have been expensed or included in rate base no adjustment to the cost of capital should be made. If flotation costs have not been recovered by one of these methods, the appropriate adjustment requires knowing how large these costs are. Estimating flotation cost is a simple accounting procedure and should be presented by PEF. Without knowing what these costs were and how they were accounted for when they were incurred, no adjustment can be made. Present investors are content with the adjustment for flotation as it has been handled historically. Without further evidence we must conclude that past flotation costs have been recovered.

Q: Dr. Vander Weide opines that PEF needs a return on equity of 12.3 percent. How do you reconcile his recommendation with your reality check model?

A: As I mentioned, the estimates forthcoming from the models used are highly responsive to their parameters and there is a great deal of latitude in the selection and estimation process that provide these parameters. Therefore, estimates outside the bounds dictated by common sense are possible if there is significant error or purposeful manipulation. At every step in his analyses Dr. Vander Weide selects parameters, or estimates parameters from chosen data sets, that favor a high estimate of the cost of capital relative to a more prudent choice. The accumulation of these errors amounts to a greatly exaggerated cost of capital.

Q: Please give examples of assumptions employed by Dr. Vander Weide that favor a high estimate of the cost of capital.

A: First, consider Dr. Vander Weide's choice to use a group of proxy companies. He selects "all of the companies in Value Line's group of electric companies that: (1) paid dividends during every quarter of the last two years: (2) did not decrease dividends during any quarter of the past two years; (3) had at least analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3; and (5) have not announced a merger."[9]

This is obviously a selected, not random, sample that skews Dr. Vander Weide's results. Recall that the DCF model estimates the cost of capital by the formula $k = \frac{CF_1}{PV} + g$ where $CF_1 = CF(1+g)$. Here g is the growth rate of earnings. It enters the equation twice: once directly as an additive component of the cost of capital and again multiplicatively to determine expected future cash flows based on today's observed cash flow. Obviously, the larger is g the larger is the estimate of the cost of capital. By eliminating companies that decreased dividends even once in the past two years this proxy group will greatly overstate the expected growth rate of earnings for the electric utility industry. Further, because the growth rate enters this equation twice (once additively and once multiplicatively), this assumption significantly biases the result. For a company with a dividend yield of five percent, each 100 basis point increase in the assumed growth rate increases the estimated cost of equity by 105 basis points.

Q: Is there evidence that this proxy group overstates the growth rate that would apply to Progress Energy?

A: Value Line's summary of Progress Energy, authored by Arthur H. Medalie on June 3, 2005 states in bold print, "We look for no earnings gain in 2005."

[9] Direct Testimony of James H. Vander Weide, p. 35.

Q: Does the proxy group affect other models Dr. Vander Weide uses?

A: Yes. In Dr. Vander Weide's application of the CAPM model beta is estimated as the average beta for the proxy group. This value is 0.81. This is significantly higher than the beta for all utilities. In fact, Compustat gives a beta for Progress Energy, Inc. of 0.16. If this is the true beta, Dr. Vander Weide attributes an additional 65 percent of the equity risk premium to PEF than is appropriate. When applied to his assumed risk premium of 7.45 percent, this overstates the true cost of capital by 484 basis points.

Q: Are there other examples of assumptions employed by Dr. Vander Weide that favor a high estimate of the cost of capital?

A: Yes, most of them do. First, the use of arithmetic means to estimate the risk premium rather than the geometric mean adds 200 basis points to the risk premium. Employing his beta of 0.81 this adds 162 basis points to his estimate of the cost of equity. (See Exhibit No. ___ (PKP-3), Appendix C for the proper derivation of the risk premium.) Second, Dr. Vander Weide assumes the risk-free rate is the Blue Chip Forecasted Long-term Treasury bond yield of 5.70%. You can get a home mortgage today for less than that. Presently 10-year Treasury bonds yield 4.09 percent. This assumption increases the estimated cost of capital by 160 basis points. In other applications, Dr. Vander Weide uses an A-rated utility bond yield of 6.94 percent. Currently A-rated utility bonds yield only 5.0 percent, thus adding 194 basis points.

Q: Are there other assumptions made by Dr. Vander Weide that tend to overstate the cost of equity for PEF?

A: Yes. Dr. Vander Weide implicitly assumes that the *projected yields* of his proxy group of utilities are the appropriate basis for the calculation of the *regulated yield* permitted for PEF. However, most utilities earn a return on investment in the upper half of the permitted range, particularly since interests rates have fallen during the past decade. Consider PEF's performance over the past decade presented below.

Progress Energy Florida: Return on Equity

Year	Authorized Return on Equity	Allowed Range of Return on Equity	Realized Return on Equity
1995	12.0%	11% - 13%	12.53%
1996	12.0%	11% - 13%	12.30%
1997	12.0%	11% - 13%	6.50%
1998	12.0%	11% - 13%	12.33%
1999	12.0%	11% - 13%	12.37%
2000	12.0%	11% - 13%	12.74%
2001	12.0%	11% - 13%	13.09%
2002	12.0%	11% - 13%	14.64%
2003	12.0%	11% - 13%	13.43%
2004	12.0%	11% - 13%	13.48%
Geometric Average	12.0%	11% - 13%	12.32%

With the exception of 1997, which involved a major rate case settlement, PEF consistently earns a return on equity greater than the FPSC authorized return. Since utility firms like PEF consistently earn return above the target yield, using their market yields to estimate the target will continuously increase the target yield when the market does not warrant it. Dr. Vander Weide should have used the *regulated yield* on his proxy utilities to account for this phenomenon.

In addition, Dr. Vander Weide includes a return to cover flotation without verifying that any flotation costs were incurred or that what was incurred has not been covered, and fails to adjust any model for the industry premium enjoyed by regulated utilities.

Q: Turning to Dr. Cicchetti's report. He supports Dr. Vander Weide's analysis that the cost of equity to PEF is 12.3 percent. Is this added support?

A: Dr. Cicchetti does not perform any analysis to confirm Dr. Vander Weide's results.

Q: Dr. Cicchetti opines that the superior performance of PEF has saved ratepayers $125 million. Can this be verified?

A: No. In fact, saving of more than this should have been realized by simply repurchasing outstanding debt. Since 1993 utility bond rates have fallen by 300 basis points. Applied to PEF's debt of approximately $10 billion this amounts to an annual saving of $300 million. Dr. Cicchetti's "proprietary model" and his reported findings are not open to scrutiny.

Q: Dr. Cicchetti suggests a 50 basis point addition to the return on equity put forth by Dr. Vander Weide as an incentive to PEF to continue "adding to its good work since the last rate case" and providing a "win/win for customers and shareholders." What do you think of this?

A: Notwithstanding the fact that there is no evidence of superior performance worthy of reward, a bonus for past performance has little incentive effect. The present Commission has only one member that was also a member of the previous Commission that established the present allowed return on equity. To be an effective incentive there has to be some reason for PEF to assume that a future Commission composed of new members would reward exemplary behavior between now and then. A bonus given like this is a win for shareholders made at the expense of customers.

Q: Shouldn't PEF be rewarded for efforts to cut costs?

A: Cutting cost is the reward. Any cost saving goes to shareholders until such time as the Commission reduces rates. This is precisely how it is supposed to be. The decisions of the Commission are designed to mimic what happens in competitive markets. In a competitive market a company that successfully innovates realizes increased profits in the short run. Over time competitors adopt the same innovations and the force of competition lowers prices and eliminates the short-run increase in profits. To perpetuate the increase in profits is to ignore the process of competition.

Q: Will customers benefit from this reward?

A: Not likely. Dr. Cicchetti's quote is "PEF proposes to reduce its current ROE to 12.8%, which would inure to the ratepayer's benefit." (Direct Testimony of Charles J. Cicchetti, Ph.D., p. 10). This is hard to imagine. At present the target ROE is 12 percent with a permitted range of 11 to 13 percent. PEF has earned in excess of 13 percent each of the last four years. Raising the ceiling 80 basis points can hardly inure to the benefit of customers. PEF has already reaped the rewards of falling interest rates and any cost saving for which PEF might be responsible. In a competitive environment these savings would result in lower rates and truly inure to the ratepayer's benefit.

Q: Does this conclude your testimony?

A: Yes it does.

FPSC DOCKET NO. 050078-EI

IN RE: PROGRESS ENERGY FLORIDA'S PETITION FOR APPROVAL OF INCREASE IN BASE RATES

DIRECT TESTIMONY OF SHEREE L. BROWN

INTRODUCTION

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Sheree L. Brown and I am the President and Managing Principal of Utility Advisors' Network, Inc., located at 530 Mandalay Rd., Orlando, Florida 32809.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A: I received a B. A. in Accounting from the University of West Florida and a Masters in Business Administration from the University of Central Florida. I am a Certified Public Accountant in the State of Florida.

I have been providing utility consulting services to municipal, cooperative, county, and institutional utilities and industrial and commercial consumers since 1981. My work has primarily focused in the areas of regulatory affairs, revenue requirement and costs of service, rates and rate design, deregulation and stranded costs, valuation and acquisition, feasibility studies, and contract negotiations.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("FPSC" OR THE "COMMISSION') AND OTHER UTILITY REGULATORY AUTHORITIES?

A: Yes. I have participated in several proceedings before the FPSC, most recently including the Progress Energy Florida ("PEF") storm surcharge case, Docket No. 041272-EI; the last Florida Power & Light Company ("FPL") general rate proceeding, Docket No. 001148-EI; the last PEF general rate proceeding, Docket No. 000824-EI; and in the 2003 Fuel Cost Recovery Proceedings, Docket No. 030001-EI, on issues relating to Tampa Electric Company's fuel costs. I have testified before the Federal Energy Regulatory Commission ("FERC"), the Arkansas Public Service Commission, the Council of the City of New Orleans, the Illinois Commerce Commission, the Louisiana Public Service Commission, the Massachusetts Department of Telecommunications & Energy, the Minnesota Public Utilities Commission, the New Hampshire Public Utilities Commission, the North Carolina Utilities Commission, and the Texas Public Utilities Commission. I have prefiled testimony and exhibits in FPL's current general rate case, Docket No. 050045-EI. I have also presented arbitration reports and live testimony in the Circuit Court of the Ninth Judicial Circuit in and for Orange County, Florida, and in the Circuit Court of the Eighteenth Judicial Circuit in and for Seminole County, Florida in PEF's recent arbitrations regarding acquisition of electric distribution facilities.

My testimony has addressed a wide range of regulatory and utility-related issues, including revenue requirement issues, cost of service, cost allocation, rate design, terms and conditions of service, merger impacts, utility valuations, stranded costs, and deregulation. My resumé and a listing of my testimony experience is included as Appendix A to my testimony.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the Florida Retail Federation ("FRF"). Members of FRF are large and small commercial users of electricity whose costs of providing goods and services to their own customers are directly impacted by increases in the costs of electricity. FRF has more than 10,000 members in Florida, many of whom take electric service from PEF.

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

A: The purpose of my testimony is to address PEF's requested increase in base rates.

<u>SUMMARY</u>

Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A: My testimony addresses PEF's proposed 2006 Test Year revenue requirement. Based on my analyses, PEF's request for a $206.6 million increase in retail base rate revenues should be reduced by at least $163.99 million, even before consideration of an appropriate fair rate of return on equity, and also before consideration of proper treatment for PEF's substantial accumulated depreciation reserve surplus. The following is a bullet-list summary of the issues I will address herein.

- PEF has overstated its Test Year employees, resulting in an overstatement of the Test Year jurisdictional revenue requirement of $2.235 million.
- PEF has included a portion of capitalized payroll taxes in the Test Year expenses, resulting in an overstatement of jurisdictional revenue requirement of $6.095 million.

- PEF has overstated its base pay expense ratio, resulting in an additional overstatement of the Test Year jurisdictional revenue requirement by $6.626 million.
- The Company erred in removing non-utility equity from its capital structure. Correction of this error reduces the Test year revenue requirement by $611,000. Based on PEF's admission of this error, I have assumed the correction as a "given" and all revenue impacts stated herein are based on the changes from the corrected requested rate increase of $204.945 million.
- PEF's capital structure adjustment for its 1997 Crystal River 3 outage cost is no longer necessary to maintain an appropriate equity ratio and should be discontinued. This adjustment reduces the Test Year revenue requirement by $9.502 million.
- PEF is requesting a 50 basis-point adder to its requested return on equity. This adder is not necessary as a performance bonus and does not provide correct incentives for future performance and should thus be denied. Elimination of this adder from PEF's requested return on equity reduces the Test Year revenue requirement by $21.9 million.
- PEF's requested rate of return on equity has also been increased by 90 basis points based on an incorrect assumption of additional financial risk. Elimination of this 90 basis point adder further reduces the Test Year revenue requirement by $39.344 million.

- PEF has included $18.7 million of incremental distribution reliability initiatives in its Test Year expenses. Based on PEF's prior estimates and actual expenditures on distribution reliability initiatives, the Test Year expenses should be reduced by $10.038 million. This adjustment reduces the retail jurisdictional revenue requirement by $10.014 million.
- PEF has also included $10 million of incremental transmission reliability initiatives in its Test Year expenses. Based on PEF's prior estimates and actual expenditures on transmission reliability initiatives, the Test Year expenses should be reduced by $2.189 million. This adjustment reduces the retail jurisdictional revenue requirement by $1.564 million.
- PEF recently sold its distribution facilities in the City of Winter Park at a gain, yet PEF failed to include amortization of the gain as an offset to the Test Year revenue requirement. Amortization of the gain over a five-year period reduces the Test Year revenue requirement by $5.96 million. PEF's sale to Winter Park has also caused cost-shifting of hurricane damage costs from customers in Winter Park to PEF's remaining retail customers. Due to the extra impact this cost-shifting will have on PEF's retail customers, it would be reasonable to shorten the typical amortization period for gains on sales of utility property to a two-year period. Amortization of the Winter Park gain over a two-year period would reduce the Test Year revenue requirement by $14.9 million.

- Based on actual historical experience, PEF has overestimated its bad debt for the Test Year. Reducing the bad debt factor to reflect historical averages reduces the Test Year revenue requirement by $1.162 million.
- In removing the retail jurisdiction storm damage asset from rate base, due to its inclusion in the Storm Damage Cost Recovery ("SDCR") clause, PEF allocated a portion of the asset to the wholesale jurisdiction. The rate base elimination was thus understated by $12.732 million. Correcting the allocation results in a reduction in the Test Year jurisdictional revenue requirement of $1.973 million.
- PEF has incorrectly stated the balances in its Last Core Nuclear Fuel ("LCNF") and End-of-Life Materials and Supplies ("EOL") reserves, thereby overstating the jurisdictional rate base. Correcting the reserve balances reduces the Test Year jurisdictional revenue requirement by $1.076 million.
- PEF has included $2.25 million in working capital associated with deferred rate case expenses. Based on past Commission precedent, this account should be removed from rate base. The impact of removing this account from rate base is a reduction of $348,618 in the Test Year jurisdictional revenue requirement.
- PEF has included $1.5 million for rate case expenses in the Test Year, based on total deferred rate case expenses of $3 million, amortized over a two-year period. Based on PEF's current earnings levels, it is

inappropriate to allow PEF to defer these costs for future amortization and the Test Year revenue requirement should be reduced by $1.5 million.

- PEF has included $82.105 million in rate base for Construction Work in Progress ("CWIP"). A review of PEF's interest coverage ratios, with and without CWIP in rate base, shows that PEF's ratios are excellent even without CWIP in rate base. Therefore, CWIP should be removed from rate base and the Test Year retail jurisdiction revenue requirement should be reduced by $12.721 million.
- PEF's request for an additional $44 million per year in storm damage accrual is excessive, particularly in light of the Commission's recent decision in PEF's 2004 storm cost recovery docket and the securitization legislation enacted and signed into Florida law this year. An increase in the annual storm damage accrual to $15.2 million a year would be sufficient to protect the Company without placing an undue burden on ratepayers. This adjustment reduces the retail jurisdiction Test Year revenue requirement by $31.125 million.

<u>PEF'S PROPOSED INCREASE</u>

Q: PLEASE DESCRIBE PEF'S PROPOSED INCREASE IN BASE RATES.

A: PEF initially requested a $206.6 million increase in base rates, effective January 1, 2006. As noted above, based on PEF's admission of its erroneous treatment of non-utility equity, I am assuming that PEF is actually requesting a base rate increase of $204.945 million per year. PEF's request includes revenues sufficient to produce a 12.8% after-tax return on equity, including a 50 basis point "adder" as an incentive or reward and a 90 basis point adder based on PEF's claim that it has more financial risk than the Company's proxy utility group..

Q: IS PEF'S REQUESTED BASE RATE INCREASE OF $204.9 MILLION REASONABLE?

A: No. PEF's proposed Test Year revenue requirement includes numerous items that have been overstated, resulting in proposed rates that are not fair, just, or reasonable. I will address each of these issues in my testimony.

LABOR EXPENSES

Q: DO YOU HAVE ANY CONCERNS REGARDING PEF'S TEST YEAR LABOR EXPENSES?

A: Yes. The Company has overstated its level of employees in developing its Test Year payroll and benefits expenses.

Q: HOW DID THE COMPANY OVERSTATE ITS LEVEL OF TEST YEAR EMPLOYEES?

A: The Company had 4,084 employees at the end of 2004. By the end of April, 2005, PEF had reduced its employees to 4,065. As explained by PEF's Witness, Mr. Portuondo, the Company has implemented a reorganization plan which includes voluntary severance and is expected to result in a net reduction of 103 positions over 2005 and into early 2006. In its response to OPC's Interrogatory No. 22, PEF stated that no positions were to be added in 2005 and 2006. However, as shown on Schedule C-35, PEF actually included an additional 46 positions in the 2006 Test Year, prior to making the adjustment to remove 103 net positions from the reorganization. This overstates the number of employees and, thus, PEF's labor expenses.

Q: SHOULD THE COMMISSION ADJUST PEF'S TEST YEAR PAYROLL AND BENEFITS EXPENSES TO REFLECT THE ELIMINATION OF THE EXTRA 46 POSITIONS?

A: Yes. The number of positions that should be included in the Test Year payroll and benefits expense estimates should be equal to the December 30, 2004 level of employees. This would comport with the Company's indication that there are no positions to be added for 2005 and 2006. This adjustment reduces the jurisdictional Test Year revenue requirement by $2.235 million as shown on Exhibit__(SLB-1).

Q: DO YOU HAVE ANY OTHER CONCERNS WITH THE LEVEL OF PAYROLL AND BENEFITS EXPENSES INCLUDED IN THE TEST YEAR REVENUE REQUIREMENT?

A: Yes. PEF has overstated the percentage of base payroll and payroll taxes charged to expenses, as opposed to being capitalized. By overstating the expense ratios, PEF has overstated the Test Year revenue requirement. In determining the appropriate Test Year revenue requirement, the Commission should correct these assumptions.

Q: PLEASE DESCRIBE HOW PEF HAS OVERSTATED THE PORTION OF ITS PAYROLL TAXES THAT IS INCLUDED IN TEST YEAR EXPENSES.

A: In the Commission Staff's Interrogatory No. 90, Staff asked PEF to explain why the percentage of payroll taxes charged to operating expense had increased from 60% in 2004 to over 83% in the Test Year. The Company's response was:

> Payroll taxes follow payroll dollars and are charged to operating expense or capital on the same basis as the actual payroll. The amount charged to operating expense varies from year to year depending on the types of projects undertaken. In 2004, a greater percentage of payroll was associated with projects that were not charged to operating expense.

However, PEF provided the percentage of payroll charged to expense for the Test Year in response to FRF Interrogatory No. 26. As shown in that response, 57% of base payroll was charged to expense—not 83% as implied in the response to Staff Interrogatory No. 90.

Further, in its response to FRF Interrogatory No. 26, the Company shows an expense ratio of 64% for FICA and unemployment, with a total of $16.040 million expensed—although Schedule C-20 shows a total of $19.574 million expensed.

Q: SHOULD THE COMMISSION ADJUST THE LEVEL OF PAYROLL TAXES INCLUDED IN THE JURISDICTIONAL TEST YEAR REVENUE REQUIREMENT?

A: Yes. As shown on the response to OPC's Interrogatory No. 26, 58% of total payroll is expensed in the Test Year. Based on the total payroll taxes of

$23,363,155, the amount expensed should thus be $13,550,630. Using the jurisdictional allocation factor of 92.421% as shown on Schedule C-20 provides a retail jurisidictional payroll tax amount of $12,523,628. Schedule C-1 shows that a portion of the expense is recovered through the ECCR and ECRC clauses. The specific amount charged to these clauses associated with the payroll taxes is $528,572 as shown in PEF's response to FRF's Interrogatory No. 16. After removal of the ECCR and ECRC clause recoveries of $528,572, the remaining jurisdictional expense to be recovered through base rates is $11,995,056.

Q: HOW DOES THIS COMPARE TO THE AMOUNT PEF INCLUDED IN THE JURISDICTIONAL TEST YEAR REVENUE REQUIREMENT?

A: As shown on Schedule C-20, PEF included $18.090 million in the jurisdictional Test Year revenue requirement. A review of Schedule C-2 shows that this amount is already net of the ECCR and ECRC clauses, since the jurisdictional expenses were first increased by the cost recovery clause amounts, which were then subtracted again to derive the same amount as shown in Schedule C-20. The net decrease in the jurisdictional Test Year revenue requirement is thus $6.095 million.

Q: PLEASE EXPLAIN YOUR CONCERN REGARDING PEF'S ASSUMPTION OF THE PERCENTAGE OF BASE PAYROLL CHARGED TO EXPENSE AS OPPOSED TO BEING CAPITALIZED.

A: The Company has increased the percentage of payroll and benefits charged to expense in the Test Year above the percentage experienced in the historical years. A review of the Base Payroll breakdown provided in response to FRF's

Interrogatory No. 16 shows a significant increase in charges to operating and maintenance expense accounts, as compared to the historical years. For example, in 2002 through 2004, the amount of base payroll charged to Account 107, CWIP, ranged from $64.2 million to $69.6 million, while the amount allocated in the Test Year is only $54.1 million. The base payroll charged to Accounts 590 to 598 in 2002 through 2004 ranged from $2.6 million to $3.3 million, yet the amount allocated in the Test Year is $17.0 million. The amount of base payroll expensed for each year from 2002 through the Test year was provided in PEF's response to OPC's Interrogatory No. 26. As shown in that response:

Year	Total Base Payroll	Amount Expensed	Percent Expensed
2002	$245,246,334	$133,597,814	54.5%
2003	$260,992,358	$141,045,171	54.0%
2004	$292,064,099	$139,809,943	47.9%
2006	$272,926,655	$156,070,270	57.2%

Even using the highest expense ratio actually experienced in the previous three-year period would reduce the amount expensed in the Test Year from $156.1 million to $148.7 million. This assumption has thus caused an increase in Test Year expenses of $7.3 million.

Q: WILL PEF BE REQUIRED TO MAINTAIN THIS EXPENSE RATIO DURING THE ACTUAL PERIOD IN WHICH BASE RATES ARE IN EFFECT?

A: No. Therefore, to the extent this ratio is overstated, the effect would be a double-recovery from ratepayers. This would occur if the expenses are actually capitalized, then recovered from ratepayers at a later date through amortization or depreciation of the capitalized items.

Q: WHAT IS YOUR RECOMMENDATION REGARDING THE LABOR AND BENEFITS EXPENSE RATIO TO BE USED IN THE TEST YEAR?

A: The Commission should adjust the base pay expense ratio based on historical experience. Understanding that there may be differences from year to year and that the ratio in 2004 may have been affected by the hurricanes, I would recommend a reduction in the expense ratio based on the highest ratio experienced over the three-year period from 2002 through 2004. The highest ratio occurred in 2002, with 54.5% of base pay capitalized. This adjustment is shown on Exhibit__(SLB-2) and reduces the jurisdictional Test Year revenue requirement by $6.626 million.

CAPITAL STRUCTURE

Q: DID PEF MAKE ADJUSTMENTS TO ITS CAPITAL STRUCTURE IN THIS CASE?

A: Yes. As explained by PEF's Witness, Mr. Sullivan, PEF has modified its capital structure to reflect several adjustments. These adjustments included an equity adder for off-balance sheet obligations, an equity adder for non-utility equity, and an adjustment to equity and long-term debt for the Crystal River 3 ("CR3") outage costs.

Q: WHY DID PEF INCLUDE AN EQUITY ADDER FOR NON-UTILITY EQUITY?

A: This adjustment was simply an error in calculating the capital structure. As PEF explained in its response to White Springs' Interrogatory No. 9, the non-utility equity should have been subtracted from equity, rather than added.

Q: WHAT IS THE IMPACT OF THIS ERROR?

A: Exhibit__(SLB-3), page 1 of 3, provides a duplication of PEF's capital structure and weighted average cost of capital from Schedule D-1a. Exhibit__(SLB-3), page 1 of 3, also includes a correction for the non-utility equity adjustment. Correction of this error reduces the revenue increase by $611,000. For purposes of the remaining capital structure issues discussed herein, I have assumed a corrected capital structure and a revised revenue increase of $204.945 million.

Q: PLEASE EXPLAIN WHY PEF MADE THE ADJUSTMENT TO EQUITY ASSOCIATED WITH THE PURCHASED POWER CONTRACTS.

A: PEF contends that the adjustment to equity for the off-balance sheet obligations associated with purchased power contracts is necessary to offset the rating agencies' practice of including such obligations as long-term debt. As explained by Mr. Sullivan, the rating agencies treat off-balance sheet obligations, such as long term purchased power contract commitments, as additional debt when assigning bond ratings. This practice has the impact of reducing PEF's equity ratio to a level that PEF deems unacceptable. As shown on Schedule D-8 and page 8 of Mr. Sullivan's testimony, the inclusion of the off-balance sheet obligations in the capital structure reduces the common equity ratio from 55.00% to 47.71%. Mr. Sullivan then notes that Standard & Poor's ("S&P") guidelines indicate that leverage (debt) ratios for utilities with PEF's business risk profile should range between 42% and 50% to achieve a single A rating. This would correspond to an equity ratio of between 50% and 58%. PEF thus makes an adjustment to its equity to allow the equity ratio to fall within the range once the rating agencies make the off-balance sheet adjustment.

Q: HOW DID PEF MAKE THE ADJUSTMENT?

A: PEF decided to target an equity structure of 55% after recognizing imputed debt associated with the purchased power contracts. As shown on Schedule D-1b, PEF added an amount to equity that is equal to the debt it anticipates the rating agencies to impute. As shown on Schedule D-1b, PEF added $757 million in equity to offset the off-balance sheet obligations, along with $8.094 million for non-utility property and $109.589 million for the CR3 adjustment.

Q: PLEASE EXPLAIN THE CR3 ADJUSTMENT.

A: In a settlement agreement approved by this Commission in Docket No. 970261-EI, PEF was allowed to adjust the balance of common equity in its capital structure to recognize certain losses the Company incurred for replacement power and operating costs during an extended outage of the CR3 unit. In Order No. PSC-97-0840-S-EI, the Commission noted that:

> Section 6 is also silent with respect to how long this adjustment will be made. The parties indicate it is contemplated within the Stipulation that this adjustment may continue beyond the four year amortization period. The only two events mentioned by the Company which would trigger an end to this adjustment after the conclusion of the four year amortization period would be a rate proceeding or a change in the law ordering industry restructuring. We are aware that under the Stipulation, this adjustment may

> continue for a number of years after the four year amortization period has concluded. (Pages 6-7)

In this case, PEF is proposing to continue the CR3 adjustment to capital structure.

Q: SHOULD THE COMMISSION ALLOW THE COMPANY TO CONTINUE THE CR3 ADJUSTMENT TO THE CAPITAL STRUCTURE?

A: No. The Company no longer has the need to make this adjustment in order to meet an appropriate equity ratio.

Q: PLEASE EXPLAIN.

A: As discussed previously, Mr. Sullivan has indicated that, in order to achieve a single A rating, an appropriate range of leverage ratios for a utility with a business risk profile such as that assigned to PEF is between 42% and 50% . This corresponds to an equity ratio of between 50% and 58%. As explained by Mr. Sullivan:

> The mid-point of this range is 46% and would be the target leverage ratio for a company seeking to achieve a "single A" credit rating. (Sullivan, page 9)

Although Mr. Sullivan indicated that 46% would be the target leverage ratio, implying a target equity ratio of 54%, PEF set a target equity ratio of 55%.

Q: IS THIS TARGET RATIO APPLIED TO PEF'S TOTAL CAPITAL STRUCTURE AS DEVELOPED FOR RATEMAKING PURPOSES?

A: No. The capital structure analyzed by the rating agencies (the structure for "financial reporting purposes") includes debt, equity, and preferred stock. It does not include the other ratemaking capital structure items, such as accumulated deferred income taxes.

Q: WHAT IS PEF'S EQUITY RATIO AFTER MAKING THE CR3 ADJUSTMENT?

A: After making the CR3 adjustment, PEF's equity ratio for financial reporting purposes is 63.00%. Without the CR3 adjustment, PEF's equity ratio for financial reporting purposes is 53.86%--directly in the middle of the target range of 50% to 58% supposedly required by S&P to achieve a single A rating. This equity ratio meets the target requirement noted by Mr. Sullivan on page 9 of his testimony. These calculations are shown on Exhibit__(SLB-3), pages 1 and 2 of 3.

Q: IS IT APPROPRIATE TO ALLOW PEF TO CONTINUE THE CR3 ADJUSTMENT INTO PERPETUITY DUE TO THE LOSSES IT INCURRED IN 1997 DURING THE EXTENDED CR3 OUTAGE?

A: No. As explained by the Commission in Order no. PSC-97-0840-S-EI:

> However, it should be pointed out that the Company has other means to increase equity including reduction of dividends, parent equity infusion and future earnings. (Page 6)

Based on the current capital structure and financial targets attested to Mr. Sullivan, the CR3 adjustment should no longer be allowed. While PEF incurred losses in 1997, it has enjoyed attractive earnings in the intervening years; therefore, this adjustment should not be continued into perpetuity.

Q: DOES THE COMPANY RECOGNIZE THE APPROPRIATENESS OF REMOVING THE CR3 ADJUSTMENT IF THE CAPITAL RATIOS ARE MET WITHOUT THE ADJUSTMENT?

A: Yes. As explained by Mr. Portuondo:

> There might be a circumstance where termination of the adjustment would be a proper outcome if, for example, it appeared in the course of a rate case that the Company were able to achieve its desired capital structure without making this adjustment. (Portuondo, Direct Testimony, Page 29)

While the Company's "desired" capital structure of 55% equity is not met without the CR3 adjustment, the 53.86% equity ratio achieved without the adjustment is in the middle of the range noted by Mr. Sullivan for maintaining an A rating.

Q: HAVE YOU CALCULATED THE IMPACT OF REMOVING THE CR3 ADJUSTMENT ON THE TEST YEAR COST OF CAPITAL?

A: Yes. Exhibit__(SLB-3), page 2 of 3, shows the calculation of the revised capital structure and weighted average cost of capital with the CR3 adjustment removed. As shown on Exhibit__(SLB-3), page 2 of 3, the Test Year revenue impact of removing this adjustment is $9.502 million.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH PEF'S CR3 ADJUSTMENT?

A: Yes. As shown on Schedule D-1b, the Company not only added the CR3 adjustment to equity, but it also subtracted the CR3 adjustment from Long-Term Debt. This provides PEF with an added bonus to equity beyond the losses incurred on CR3.

Q: PLEASE EXPLAIN HOW THE SUBTRACTION OF THE CR3 "EQUITY" FROM LONG-TERM DEBT PROVIDES PEF WITH AN ADDITIONAL EQUITY BONUS.

A: Exhibit__(SLB-3), page 3 of 3, shows the capital structure calculations without the CR3 adjustment to debt. A comparison of the capital structure without the CR3 debt adjustment to the corrected capital structure shown on Exhibit__(SLB-3), page 1 of 3, shows the impact of PEF's adjustment on the equity component of the capital structure. The impact of subtracting the CR3 adjustment from Long-Term Debt is an increase in the equity component of the capital structure from 56.72% to 57.72% and an increase in the overall return from 9.43% to 9.49%. By subtracting the CR3 adjustment from long-term debt, PEF also increased the equity ratio for financial reporting purposes from 61.80% to 63.00%. As shown on Exhibit__(SLB-3), page 3 of 3, when applied to PEF's Test Year rate base, the revenue impact associated with PEF's CR3 adjustment to long-term debt is $4.975 million.

Q: WHAT IS YOUR RECOMMENDATION IN THIS CASE REGARDING THE CR3 ADJUSTMENT?

A: For the reasons stated above, the CR3 adjustment should be removed in its entirety – from both equity and long-term debt -- and the Test Year revenue requirement should be reduced by $9.502 million. If, however, the Commission chooses to allow continuation of the CR3 equity adjustment, the adjustment to the long-term debt component should be eliminated and the Test Year revenue requirement should be reduced by $4.975 million.

COST OF CAPITAL

Q: DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S REQUESTED COST OF CAPITAL?

A: Yes. While I am not specifically opining on a recommended ROE for PEF, I have two specific, major concerns with PEF's requested cost of capital. First, the Company has requested a 50 basis point adder to its proposed rate of return on equity as a supposed performance incentive. As shown on Exhibit__(SLB-4), page 1 of 3, this adder increases the Test Year revenue requirement by $21.9 million, or 10.67% of the total requested increase in base rates (as revised to reflect the non-utility equity adjustment error). Second, the Company's cost of capital witness, Dr. Vander Weide, has adjusted his recommended cost of equity upwards by 90 basis points based on his determination that "PEF's capital structure embodies greater financial risk than the average market value capital structures of my proxy company groups." (Dr. Vander Weide direct testimony, page 57) As shown on Exhibit__(SLB-4), page 1 of 3, this adder increases the Test Year revenue requirement by $39.344 million, or 19.2% of the total requested increase in base rates, as adjusted for the non-utility equity adjustment error. Therefore, the combined adders account for approximately 30% of PEF's requested increase in this case. Neither of these adjustments should be allowed.

Q: WHY SHOULD THE COMMISSION DENY PEF'S REQUESTED 50 BASIS-POINT ADDER TO ITS RETURN ON EQUITY?

A: As I explain in more detail in my testimony below, the Commission should deny this requested 50 basis-point adder for several reasons:

- It is not a reasonable cost of providing service.
- Much of the claimed savings that PEF asserts were provided to ratepayers in Docket No. 000824-EI were, in fact, no savings at all, but rather deferred costs for which PEF is now seeking recovery.
- The cost savings that PEF has realized during the term of the 2002 settlement in Docket No. 000824-EI have accrued solely and exclusively to PEF's shareholders, through higher profits, and to PEF's employees, through incentive payments. In other words, PEF is now asking for an additional reward over-and-above the substantial bottom-line profits that its shareholders have already enjoyed and in which its customers have not shared.
- The proposed adder is not a meaningful incentive for future behavior.

Q: WHAT IS THE COMPANY'S JUSTIFICATION FOR THE 50-BASIS POINT ADDER?

A: PEF's witness, Dr. Cicchetti, attests to the Company's justification for a 50-basis point adder. Dr. Cicchetti encourages the Commission to allow this adder to reward PEF for superior performance and the achievement of savings. Dr. Cicchetti explains that the Company's actions have already yielded $125 million in annual benefits to customers and that the Company is now willing to *reduce* its currently-earned return on equity ("ROE") to 12.8%. He argues that the Company's efforts should be rewarded and it should be encouraged to continue to improve performance, build up its equity, and improve its bond ratings.

Q: HAVE THE COMPANY'S ACTIONS REALLY YIELDED $125 MILLION IN ANNUAL BENEFITS TO CUSTOMERS?

A: No. A review of the Settlement and Stipulation in Docket No. 000824-EI shows that the $125 million rate reduction consisted more of cost deferrals than real savings. Fully one-half of the reduction was associated with the suspension of $62.5 million in depreciation expense. Another $8.733 million was suspension of decommissioning costs. Another $5.27 million was suspension of the fossil dismantlement charges. Therefore, $76.503 million, or 61.2%, of the total "reductions" were merely *deferrals* of costs, not *true* savings. In fact, in this proceeding, customers are already seeing the impact of the deferred depreciation expense which is offsetting the reductions to depreciation expense that would otherwise be enjoyed as a result of the new depreciation study.

Q: BUT, HASN'T THE COMPANY SUCCESSFULLY REDUCED OPERATING EXPENSES?

A: As will be demonstrated later in my testimony, the Company has successfully reduced certain operating expenses from the levels it claimed in Docket No. 000824-EI. These reductions, however, have not been enjoyed by PEF's customers but have, instead, accrued to PEF's shareholders in the form of higher returns on equity. Further, it appears that other projected costs that PEF claimed in Docket No. 000824-EI for service improvements have been deferred and are now showing up again in PEF's current cost projections.

Q: DR. CICCHETTI ALSO CLAIMS THAT RATEPAYERS HAVE ALSO RECEIVED $45.9 MILLION IN REVENUE SHARING REFUNDS. WERE THESE REFUNDS ATTRIBUTABLE TO PEF'S EFFORTS AT REDUCING COSTS?

A: No. These revenue sharing refunds are not attributable to PEF's cost reductions in any way. Under the Stipulation and Settlement in Docket No. 000824-EI, the Company agreed to share revenues above a certain threshold. Revenues are primarily driven by customer growth and weather. Any cost reductions achieved by PEF were retained by PEF and resulted in higher returns on equity. In fact, PEF achieved very high rates of return on equity during the time that the 2002 Stipulation and Settlement has been in effect, in part by means of not making expenditures that it represented that it would make in Docket No. 000824-EI.

Q: IS THE RATE OF RETURN ADDER A REASONABLE COST OF PROVIDING SERVICE?

A: No. PEF shareholders have been rewarded for the Company's successes in reducing costs through the higher returns earned over the last several years. The rate of return adder is simply an additional requested reward mechanism. PEF has not shown how the rate of return adder will provide an incentive for better future performance or why investors need a return greater than the "fair" return in order to invest capital in PEF.

Q: WHY DOESN'T A RATE OF RETURN ADDER PROVIDE AN INCENTIVE FOR BETTER FUTURE PERFORMANCE?

A: Under the current regulated ratemaking treatment, utilities have the incentive to cut costs between rate cases, regardless of the authorized return on equity. A rate of return adder will thus not increase the utility's incentive to achieve cost savings.

Q: PLEASE EXPLAIN WHY UTILITIES HAVE THE INCENTIVE TO CUT COSTS BETWEEN RATE CASES.

A: Utilities, like any other business, seek to maximize profits. Profits can be maximized by increasing revenues or reducing costs. For utilities, however, revenues are generally not controllable, so utilities focus on cost reductions as a means to maximize profit.

Under current regulated ratemaking treatment, there are essentially three components to the development of rates: (a) costs that are passed-through directly to consumers through adjustment clauses, (b) costs that are included in the development of base rates with no markup to the utility, and (c) the fair return on assets invested to serve customers, which is also incorporated into base rates.

Regulated utilities operating in a monopolistic market have an obligation to serve their customers reliably at the lowest possible costs. However, unlike entities operating in a competitive environment, Florida's regulated utilities are insulated from a large portion of the normal operating risks faced by unregulated entities. The customer base is not at risk due to poor performance and the recovery of a large percentage of operating costs is essentially guaranteed through cost recovery clauses (subject to prudency review) or through tax adders to customer bills. These clauses significantly reduce the utility's risks of operations by essentially "guaranteeing" the Company recovery of prudently incurred costs. As shown in PEF's December, 2004 Surveillance Report, in 2004, 59.42% of PEF's revenues were received through cost recovery clauses and adders. Cost recovery clauses accounted for 54.96% of PEF's jurisdictional revenue and 4.47% was recovered through direct tax adders to customer bills. The cost recovery clauses and adders covered approximately 67.09% of PEF's total operating expenses. This does not provide incentives for the utility to reduce costs, but does protect against volatility of expenses, thereby reducing risks of losses to shareholders.

PEF's remaining expenses are included on a dollar-for-dollar basis in the development of base rates using a proforma Test Year. Once those rates are established, PEF's profitability is dependent upon the actual costs incurred (which is controllable by PEF) and the level of revenues received (which is not controllable by PEF). This portion of the ratemaking process thus gives the utility two incentives: the first is to overestimate expenses and underestimate sales and revenues when seeking a change in base rates, and the second is to reduce expenses between rate proceedings in order to maximize profits.

Under current regulatory ratemaking, the last component of a utility's rate structure is the return on rate base. In exchange for the obligation to serve, the regulated utilities are provided with an opportunity to earn a fair return on their investments in assets used to serve customers. Since rates are set to include a fair return on the utility's investment in assets used to serve customers, the incentive is to maximize investment and to persuade the regulatory authority to set its "fair return" as high as possible.

After the rates are set, the utility will attempt to maximize its profits by reducing its costs. Although it cannot control sales, the utility will also reap the benefit of higher sales if its rates are set based on an unrealistically low sales estimate.

Q: HOW WOULD A RATE OF RETURN ADDER CHANGE THE COMPANY'S INCENTIVES?

A: A rate of return adder will not change the utility's incentives. Since actual returns are not based on the rate of return set in a rate proceeding, an "incentive" rate of return adder would not change the Company's incentives. Once rates are set, the Company will still have the incentive to maximize returns by reducing expenses between rate cases. A rate of return adder will not really provide an incentive to promote future performance. Such an adder would simply be an additional reward.

Q: DOES A UTILITY NEED A RATE OF RETURN ADDER TO ENCOURAGE INVESTORS TO INVEST CAPITAL IN THE COMPANY?

A: No. The discounted cash flow and risk premium methodologies employed by the cost of capital witnesses already reflect the relative risk of the Company and the markets in which it is operating. The Company's proposal for a rate of return adder provides additional "upside" for the Company, while still providing the protections inherent in regulation. This adder is not a reasonable cost of providing service, is not necessary to attract capital, and does not provide any additional incentives for improved performance. PEF's proposed adder would be a windfall to shareholders at customer expense.

Q: ARE RATEPAYERS PAYING FOR OTHER PERFORMANCE INCENTIVES?

A: Yes. As shown on Schedule C-35, PEF has estimated that it will incur $19.4 million in Test Year incentive compensation. In 2004, the incentive compensation was $26.6 million. Even with this level of performance-based compensation, the Company still earned a 13.48% rate of return on equity on an FPSC adjusted basis.

Q: SHOULD THE COMMISSION APPROVE PEF'S PROPOSED ROE ADDER OR SOME OTHER ADDER AT A LOWER LEVEL?

A: No. The Commission should not approve any adder to the "fair" ROE. As demonstrated above, any rate of return adder is not a legitimate or reasonable cost of providing service and is not an appropriate or meaningful incentive for future performance.

Q: DR. CICCHETTI DISCUSSED PERFORMANCE BASED AND INCENTIVE PLANS IN OTHER NON-RESTRUCTURING JURISDICTIONS. DO YOU HAVE ANY CONCERNS REGARDING DR. CICCHETTI'S CONCLUSIONS?

A: Yes. On page 44 of his testimony, Dr. Cicchetti described a sharing plan employed by the Georgia Public Service Commission. As explained by Dr. Cicchetti, Georgia Power Company has a sharing plan that authorizes it to earn an ROE within a specified band. This band ranges from 10.25% to 12.25%. If Georgia Power earns above the ROE band range, it shares the excess earnings with its customers. In response to FRF's Interrogatory No. 25, the Company also provided a description of the performance incentive plans for the other companies listed in Table 10 of Dr. Cicchetti's testimony. As shown in that response, each of these companies is subject to some form of sharing when profits are above a predetermined range. Even though Dr. Cicchetti's proposed ROE adder does not include a sharing provision, he concludes that:

> While PEF is not suggesting a performance based sharing mechanism be implemented at this time, the 50 basis point adder for PEF's superior performance accomplishes the same incentives, and as I described above, would be a good approach for PEF. (Dr. Cicchetti Direct Testimony, page 45)

I have two concerns with Dr. Cicchetti's conclusion. First, as explained earlier in my testimony, the Company's incentive to reduce costs to maximize returns is inherent in the regulated ratemaking process, regardless of the rate of return earned. Second, while the performance incentives referenced by Dr. Cicchetti are designed to provide ratepayers with at least a portion of the benefits from future cost savings, the 50 basis point adder recommended by Dr. Cicchetti is one-sided and does not provide any benefits to customers based on any future cost reductions achieved by the Company. The proposed adder would simply give PEF higher rates and an increased opportunity to reap even greater profits, without any sharing of cost reductions or enhanced profitability benefits with customers.

Q: WHAT IS THE IMPACT OF ELIMINATING PEF'S REQUESTED 50 BASIS POINT ROE ADDER TO ITS REQUESTED RETURN ON EQUITY?

A: Eliminating the 50 basis point adder reduces PEF's requested rate of return from 9.49% (adjusted for the non-utility equity error) to 9.21%. This adjustment reduces the Test Year revenue requirement by $21.9 million, as shown on Exhibit__(SLB-4), page 1 of 3.

Q: PLEASE DESCRIBE THE 90 BASIS POINT ROE ADJUSTMENT MADE BY DR. VANDER WEIDE.

A: Dr. Vander Weide selected two proxy groups on which he calculated the average return on equity, using five different cost of equity models. He determined that the average cost of equity for these two groups is 11.4%. However, he then added 90 basis points to his recommended ROE for PEF based on his claim that PEF's capital structure was more risky than the average capital structure of the proxy groups. He determined the level of adjustment by determining the weighted average cost of capital of the proxy groups, then "backing into" the ROE that would be required for PEF to earn the weighted average cost of capital, given its supposedly higher debt ratio.

Q: WHY IS DR. VANDER WEIDE'S PROPOSED 90 BASIS-POINT ROE ADJUSTMENT INAPPROPRIATE?

A: Dr. Vander Weide's 90 basis-point adjustment to ROE is inappropriate for two reasons. First, capital structure is not the only risk that rating agencies or investors take into account when determining a company's risk relative to other potential investments. In fact, Dr. Vander Weide lists a myriad of risk factors considered by the investment community. Investment analysts assign measures of risk to companies, such as S&P's "business risk profile" ranking and ValueLine's safety rating. Dr. Vander Weide's ROE analyses have already taken these risk measures into account.

Second, Dr. Vander Weide based his adjustment on PEF's target capital structure, which incorporates 55% equity *after* including an adjustment to the debt component for PEF's purchased power contracts. Dr. Vander Weide did not, however, make similar adjustments to his proxy groups, thereby overstating their equity components relative to PEF's.

Q: PLEASE EXPLAIN HOW DR. VANDER WEIDE'S ROE ANALYSES HAVE ALREADY TAKEN THE RISK MEASURES INTO ACCOUNT.

A: As Dr. Vander Weide explain on page 14 of his testimony:

> The comparable company approach estimates PEF's cost of equity by identifying a group of companies of similar risk.

He then goes on to describe the primary factors that affect the business and financial risks of companies such as PEF. Those factors included demand uncertainty, operating expense uncertainty, investment uncertainty, high operating leverage, high degree of financial leverage, and regulatory uncertainty.

On pages 36 and 37 of his testimony, Dr. Vander Weide claims that his electric company proxy group is comparable in risk to PEF. He notes that the average Value Line Safety Rank for the proxy group was 2 and that the Value Line Safety Rank for PEF's parent company is also 2. He also claims that the average S&P bond rating of his chosen proxy group is "approximately BBB+" with an average business risk profile of 5.7 and that the S&P bond rating for PEF's parent company is BBB with a business risk profile of 6. While PEF's parent company may have a business risk profile of 6, PEF's other witness, Mr. Sullivan, noted, on page 8 of his testimony, that S&P considers PEF to have a business risk profile of 5.

Q: DID DR. VANDER WEIDE SPECIFICALLY ANALYZE THE RISK FACTORS OF THE VARIOUS COMPANIES IN HIS PROXY GROUPS?

A: No.

Q: IF THE COMMISSION WERE TO EVALUATE THE VARIOUS RISK FACTORS MENTIONED BY DR. VANDER WEIDE, WHAT ARE SOME OF THE SPECIFIC FACTORS THAT SHOULD BE TAKEN INTO CONSIDERATION FOR PEF?

A: Dr. Vander Weide noted several operating expense uncertainties, including:

(a) the prospect of rising employee health care and pension expenses;

(b) variability in storm-related expenses due to severe weather;

(c) the prospect of increased expenses for security related to the threat of terrorist activities;

(d) high volatility in fuel prices; and

(e) uncertainty in the cost of purchased power.

The Commission, however, should readily recognize that PEF is quite effectively insulated from all but one of these uncertainties. In fact, the price uncertainties associated with storm-related expenses, incremental security costs, fuel costs, and purchased power are all greatly mitigated, by the use of adjustment clauses and surcharges. As explained above, more than 67% of PEF's total operating expenses are covered through pass-through clauses and tax adders. While PEF does bear the risk of uncertainties in health costs and pension expenses, this is a common price risk that is spread among all companies in all industries.

PEF's recovery of costs through adjustment clauses and the recent decision in the storm damage case, along with the recent enactment of the Securitization Bill into Florida law, should also mitigate concerns over regulatory risks. Further, the lack of movement towards retail competition in Florida provides additional assurances for investors.

PEF recognizes the reduction in risks associated with the Commission's treatment of its purchased power expenses. In fact, in a letter to S&P on April 12, 2005, PEF's witness, Mr. Sullivan, claimed that:

> The recovery mechanism in place for capacity payments associated with all of Progress Energy Florida's (PEF) purchase power payments, in particular its qualifying facilities (QFs), eliminates any risk associated with future disallowance. It is our strong opinion that S&P should assign a zero risk factor to these capacity payments in its calculation of imputed debt . . . . The follow [sic] summarizes our basis for asserting there is essentially no risk of future disallowance . . . . In summary, we've demonstrated in our presentation and reiterated above, that the risk of disallowance of recovery is essentially nil . . . . This future cash flow stream is certain and therefore insulates

bondholders from any incremental financial risk associated with these contracts. (FRF Request for Production of Documents No. 28)

Q: YOU INDICATED THAT DR. VANDER WEIDE CALCULATED THE 90 BASIS POINT ADDER BY "BACKING INTO" THE ROE REQUIRED TO PROVIDE PEF WITH THE WEIGHTED AVERAGE COST OF CAPITAL FOR THE PROXY GROUPS. WHY SHOULD THE COMMISSION REJECT THIS ADDER?

A: Dr. Vander Weide calculated an average capital structure for the electric proxy group as having 40.7% debt, 1.34% preferred stock, and 57.97% common equity. Based on this capital structure, the weighted cost of capital would be 8.433%. He then calculated the average capital structure for the gas proxy group as having 33.90% debt, .24% common stock, and 65.86% common equity. Based on this capital structure, the weighted cost of capital for the gas group would be 8.962%. He then averaged the weighted cost of capital for the two proxy groups, which was 8.697%. When he applied this overall cost of capital to PEF's target structure, the after-tax cost of common equity was 12.35%.

Q: WHAT WAS THE IMPACT OF APPLYING THIS ADJUSTMENT BASED ON THE AVERAGE CAPITAL STRUCTURE OF THE GAS AND ELECTRIC PROXY GROUPS, RATHER THAN JUST APPLYING THE ADJUSTMENT BASED ON THE AVERAGE CAPITAL STRUCTURE OF THE ELECTRIC PROXY GROUP?

A: If Dr. Vander Weide had just applied the weighted cost of capital from the electric proxy group, rather than weighted cost of capital from both the gas and electric groups, his adjustment would have increased the after-tax cost of common equity to only 11.869%, rather than 12.35%.

Q: WHAT TARGET CAPITAL STRUCTURE DID DR. VANDER WEIDE USE IN MAKING HIS CALCULATIONS?

A: Dr. Vander Weide used PEF's targeted capital structure with 55% equity and 45% debt.

Q: IS THIS THE APPROPRIATE CAPITAL STRUCTURE TO USE WHEN COMPARING PEF TO THE UTILITIES IN DR. VANDER WEIDE'S PROXY GROUP?

A: No. It should be noted that this is the capital structure PEF claims would be applicable before any adjustment for the off-balance sheet obligations; however, PEF made several adjustments to its capital structure to offset the off-balance sheet obligation adjustment that it anticipates will be made by the rating agencies. Unless Dr. Vander Weide makes off-balance sheet adjustments to the capital structures of his chosen proxy group, his adjustment should reflect the capital structure achieved after applying the Company's proposed adjustments to equity. In other words, the capital structure comparison made by Dr. Vander Weide was comparing "apples to oranges." As explained earlier in my testimony, PEF has made an adjustment to increase equity so that, when rating agencies apply the off-balance obligation adjustment, PEF will be at its targeted capital structure. As shown on Exhibit__(SLB-4), page 2 of 3, PEF's capital structure after all of its recommended adjustments provides 63.00% common equity, .59% preferred stock, 35.82% long-term debt, and .59% short-term debt. This is the capital structure that should be compared to the proxy group capital structures in order to compare "apples to apples" in making the adjustment proposed by Dr. Vander Weide. If Dr. Vander Weide's methodology were applied to this capital structure, the resulting ROE would be 10.87% as shown in the table below.

Class	Ratio	Cost Rate	Weighted Cost Rate
Long-term Debt	35.82%	4.23%	1.515%
Short-term Debt	.59%	4.23%	.025%
Preferred Stock	.59%	7.64%	.045%
Common Equity	63.00%	10.87%	6.848%
Total	100.00%		8.433%

Q: WHAT WOULD BE THE REVENUE IMPACT OF REDUCING PEF'S ROE TO 10.87%?

A: As shown on Exhibit__(SLB-4), page 3 of 3, if Dr. Vander Weide had utilized the Company's proposed capital structure in making his risk adjustment, the resulting ROE would have been 10.87%. The revenue impact of decreasing the return on equity from the Company's recommended ROE of 12.8% is $61.2 million, or 29.86% of PEF's requested increase in base rates (as adjusted for the non-utility equity error). This includes the impact of removing the 50 basis point adder, which is $21.9 million; therefore, the individual impact of reducing the ROE from Dr. Vander Weide's recommended 12.3% rate to the recalculated 10.87% rate is $39.3 million, or 19.2% of the Company's adjusted rate increase.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A: PEF has made several adjustments to its capital structure and cost of equity which are unnecessary, do not provide proper incentives, and reflect improper risk adjustments. The Commission should reject PEF's proposals to (i) continue the CR3 adjustment to the capital structure (ii) increase the ROE by 50 basis points as a performance reward, and (iii) increase the ROE by 90 basis points to reflect PEF's risk relative to the proxy group. These adjustments should not be reflected in the Commission's final determination of the cost of capital for PEF, based upon its evaluation of the fair rate of return on equity. In addition, the non-utility equity adjustment error should be corrected.

Q: SHOULD THE COMMISSION CONSTRUE YOUR TESTIMONY AS SUPPORTING OR AGREEING THAT AN ROE OF 10.87% IS REASONABLE?

A: No. My recommendations only extend to eliminating PEF's requested 50 basis point "incentive" reward and its 90 basis-point "riskiness" factor. There are many other factors that go into determining a fair rate of return on equity, and many other analyses that are performed in such determinations, which have been addressed by other witnesses in this case.

DISTRIBUTION RELIABILITY INITIATIVES

Q: PEF HAS INCLUDED $18.7 MILLION OF COSTS FOR CLAIMED "INCREMENTAL" DISTRIBUTION RELIABILITY INITIATIVES IN ITS TEST YEAR REVENUE REQUIREMENT. DO YOU HAVE ANY CONCERNS REGARDING PEF'S PROPOSED DISTRIBUTION EXPENSES?

A: Yes. In PEF's last rate filing in Docket No. 000824-EI, PEF included a substantial increase in distribution operation and maintenance expenses associated with its distribution reliability initiatives. PEF's witness in that case, Mr. Robert Sipes, supported increases associated with these distribution reliability incentives of over $20 million in operating and maintenance expenses and over $126 million in capital expenditures over the 2002 through 2004 period. While PEF claims to have made significant improvements in its distribution system, based on reduced outages, a review of actual expenditures over the 2002 through 2004 time frame shows that PEF spent significantly less than it had projected. Now PEF wants to, again, include a significant "adder" in its Test Year projected operating and maintenance expenses, even though it did not spend what it represented to the Commission that it would spend over the past three years.

Q: WHAT WAS THE LEVEL OF PEF'S OVERSTATEMENT OF DISTRIBUTION RELIABILITY INITIATIVE COSTS IN DOCKET NO. 000824-EI?

A: In PEF's response to OPC's Interrogatory No. 49, PEF provided a breakdown of the actual expenditures for its distribution initiatives. A comparison of PEF's claimed distribution reliability initiative costs in Docket No. 000824-EI to its actual expenses incurred is shown in the following table.

Description	O&M ($MM)	Capital ($MM)
Docket 000824-EI Projections[1]	$20.139	$126.807
Actual Expenditures[2]	$9.300	$47.600
Overestimate	$10.839	$79.207
Percent Overestimated	116.5%	166.4%

Q: DID PEF COMPLETE THE PROGRAMS THAT IT INCLUDED IN ITS REQUESTED REVENUE REQUIREMENT IN DOCKET NO. 000824-EI?

A: That is a good question that apparently has several different answers.

In PEF's recent storm damage case, Docket No. 041272-EI, Mr. Portuondo noted that:

> The Company has made a commitment to the Commission and its customers to improve customer satisfaction and system reliability as part of its Commitment to Excellence. In order to fulfill this commitment, the Company was on track to perform a number of activities that got interrupted by the hurricanes. (Portuondo Rebuttal, Docket No. 041272-EI, page 31.)

In that same docket, another PEF witness, Mr. Wimberly, stated:

> PEF's Commitment to Excellence (CTE) program identified in 2001 investments in the transmission and distribution systems . . . . The Company started work on improving reliability immediately in 2001 and fulfilled its CTE program by 2004, before the hurricanes started in late

[1] Docket No. 000824-EI, Exhibit RAS-1.
[2] PEF's Response to OPC's Interrogatory No. 49.

> August. (Wimberly Rebuttal, Docket No. 041272-EI, Page 6) (Emphasis in original).

In this case, PEF's witness, Mr. McDonald also indicates that the program was completed.

> . . .This was accomplished through the successful completion of our Commitment to Excellence (CTE) program as well as other, additional initiatives. (McDonald Direct Testimony, Page 3)

Mr. Oliver also contends that the program was completed:

> We successfully completed our Commitment to Excellence program, making significant improvements in several areas of our operations for employees and customers. (Oliver Direct Testimony, page 3)

A review of the Docket No. 000824-EI projections for the distribution reliability initiatives compared to actual expenditures over the 2002 through 2004 period shows that a number of expected projects were either not completed or cost substantially less than PEF had represented. For example, the Company projected $1.5 million for the Transformer Replacement and Inspection Program, yet only spent $100,000. The Company also projected $6.432 million in Targeted Feeder Analysis, yet only spent $2.9 million in total for "other initiatives", including the Targeted Feeder Analysis (as well as infrared inspection, small diameter OH wire, system contingency improvements, AMR, data mapping Suncoast network, switch maintenance, RUDI, project management, visual inspection program overhead mechanical switches, and prior year programs, per PEF's response to OPC's Interrogatory No. 49).

Based on the actual expenditures, as compared to the projections provided in Docket No. 000824-EI, there are two conclusions that could be reached: either the programs have not been completed, or PEF's costs of completing the programs were significantly less than the Company estimated.

Q: WHAT IS THE POTENTIAL IMPACT OF OVERESTIMATING EXPENSES WHEN SETTING RATES?

A: As explained earlier, under standard regulatory ratemaking practices, the utility has the incentive to overestimate expenses when setting rates, and then to cut back on expenses to increase returns after the rates are in place. While I cannot definitively say *why* PEF overestimated its distribution expenses in Docket No. 000824-EI, the result is the same. Exhibit__(SLB-5) summarizes projected versus actual distribution spending from 2002 to 2004 and projected versus actual distribution initiative spending over that same period. Although PEF projected $6.948 million in annual operating and maintenance expenses for distribution reliability initiatives in Docket No. 000824-EI, it actually spent an average of only $3.1 million a year from 2002 through 2004. The overstatement of costs is even greater when PEF's total distribution operating and maintenance expense projection in Docket No. 000824-EI is compared to its actual expenditures for the same period. PEF projected annual distribution O&M expenses of $97.1 million, or $291.3 million over the 3 year period. Actual expenditures were only $259.9 million, indicating an overstatement of $31.44 million, or 12.1%, over the three-year period. This overstatement had the impact of increasing PEF's return on equity. In 2004, the overstatement increased PEF's after-tax return on equity by 0.3741% (37 basis points).

Q: HAS PEF MADE ANY OTHER STATEMENTS THAT INDICATE THAT IT CONTROLS ITS EXPENDITURES TO MEET ITS FINANCIAL OBJECTIVES?

A: Yes. In Staff's Interrogatory No. 48, Staff asked PEF;

> What assurance does PEF provide to ensure each of the reliability programs listed in MFR C-041 and Exhibit DM-2 are implemented as budgeted?

PEF's response explained that PEF continually revises its plans and initiatives. PEF also noted that:

> . . . these initiatives are subject to the reasonable business judgment of management as to prioritizing among the initiatives, as well as to maintaining the overall financial strength of the Company, including maintaining a favorable credit rating . . . .

Therefore, PEF has acknowledged that it does control expenses to meet its financial objectives.

Q: WHAT IS THE LEVEL OF EXPENSE THAT PEF HAS INCLUDED IN THE TEST YEAR FOR DISTRIBUTION RELIABILITY INITIATIVES?

A: As shown on Exhibit No.__(DM-2), PEF has included $18.65 million in incremental distribution reliability initiatives for the Test Year. A breakdown of the costs, by program, is as follows:

Program	Amount ($MM)
Pole inspections, treatment reinforcement and replacement	$0.90
Switchgear inspection, repair and replacement	$0.25
Transformer inspection, repair and replacement	$2.30
Network Maintenance	$0.80
Data mapping	$1.50
Feeder monitoring system	$0.70
Infrared scanning & repair	$0.90
Capacitor maintenance	$0.30
Vegetation Management	$11.00
Total	$18.65

Q: ARE ANY OF THESE PROGRAMS CONTINUING PROGRAMS THAT WERE PREVIOUSLY INCLUDED IN PEF'S DISTRIBUTION RELIABILITY INITIATIVES?

A: Yes. As shown in Exhibit__(DM-2), vegetation management makes up the largest single cost for the Test Year. Incremental vegetation management costs were projected at $1.62 million per year in Docket No. 000824-EI. Actual incremental expenditures for this program were $1.6 million, $600,000, and $1.9 million for 2002, 2003, and 2004, respectively. In response to OPC's Interrogatory No. 111, PEF shows that actual vegetation management expenses (base funding and incremental) for 2004 were $15.410 million. PEF's distribution expense budget already includes $15.260 million for vegetation management in 2006. It is requesting an additional $11 million under its distribution reliability initiatives adder. This is an increase of 72% over budget.

In addition to the large requested increase in incremental vegetation management costs, it appears that costs may have been deferred into the Test Year. For example, as noted previously, transformer replacements and inspections were projected to cost $1.5 million in Docket No. 000824-EI, yet PEF only spent $100,000 on this program. Now, in the current Test Year, PEF is requesting an additional $2.3 million for transformer inspections, repairs, and replacements. This is a clear example of the ratemaking incentives I described earlier in my testimony. When setting rates, PEF overstated its expenses, then, in the intervening years, PEF spent less than it had included in setting its base rates, resulting in higher profits.

Q: HOW SHOULD THE COMMISSION RESPOND TO PEF'S PROPOSAL TO INCREASE ITS DISTRIBUTION RELIABILITY INITIATIVES?

A: The Commission should eliminate a portion of the projected incremental distribution reliability initiatives based on its history of projections versus actual expenditures. Given PEF's previous overstatement of $10.5 million a year, on average, the overstatement was approximately 116.5%. On average, PEF spent only 46.2% of the amount it estimated. Using the same ratio to adjust PEF's proposed Test Year incremental reliability initiatives would decrease the Test Year revenue requirement by $10.038 million, as shown on Exhibit__(SLB-5). This would reduce the jurisdictional revenue requirement by $10.014 million.

<u>Transmission Reliability Initiatives</u>

Q: DID PEF ALSO OVERESTIMATE TRANSMISSION SPENDING IN DOCKET NO. 000824-EI?

A: Yes. As with the distribution reliability initiatives, PEF's estimates of transmission expenses were significantly overstated in Docket No. 000824-EI. Exhibit__(SLB-6) summarizes PEF's projected versus actual transmission spending from 2002 to 2004 and project versus actual transmission initiative spending over that same period. Over the three-year period from 2002 through 2004, PEF estimated total operating and maintenance expenses of $34.3 million a year, or $102.9 million, with reliability initiatives accounting for $9.73 million a year, or $29.19 million of the total. Actual transmission operating and maintenance expenses over the same time period were only $85.874 million, indicating an overstatement of $17.026 million or 19.8%. Actual expenditures for transmission reliability initiatives were only $22.8 million; therefore, PEF overstated the operating and maintenance expense portion of the transmission reliability initiatives by $6.39 million, or 28%.

Q: DID PEF ALSO OVERESTIMATE ITS CAPITAL SPENDING ON TRANSMISSION RELIABILITY INITIATIVES IN DOCKET NO. 000824-EI?

A: Yes. In that case, PEF estimated that a total of $37.54 million would be spent in capital for transmission reliability initiatives over the 2002-2004 time frame. Actual capital expenditures were only $14.4 million. PEF thus overstated its capital expenditures by $23.14 million, or 161%.

Q: DID PEF BENEFIT FROM ITS LOWER SPENDING LEVELS?

A: Yes. For example, in 2004, PEF's transmission operating and maintenance expenses were only $26.716 million, as compared to the $34.3 million estimate. The lower level of expenses flowed directly to PEF's profit, resulting in an increase of $4.658 million in PEF's after-tax return, or 0.2334% (23 basis points). When combined with the increase in after-tax return of 0.3741% associated with the distribution cost reductions, PEF enjoyed an increased return of 0.6075% (61 basis points) in 2004 by keeping transmission and distribution costs lower than anticipated in its last rate filing.

Q: IS THE COMPANY ASKING FOR FURTHER RELIABILITY INITIATIVES TO BE INCLUDED IN THE TEST YEAR REVENUE REQUIREMENT?

A: Yes. As explained by PEF Witness, Mr. Desouza, PEF is requesting an additional $10 million in "accelerated & proactive reliability initiatives." (Desouza Direct Testimony, Pages 11-12)

Q: SHOULD THE COMMISSION ADJUST PEF'S REQUESTED TEST YEAR TRANSMISSION EXPENSES?

A: Yes. PEF's transmission reliability initiative costs for the Test Year should be limited to the percentage of actual expenses incurred from 2002 through 2004 as compared to estimated expenses in Docket No. 000824-EI. This adjustment would reduce the Test year transmission operating and maintenance expenses by $2.189 million. The jurisdictional revenue impact of this adjustment is $1.564 million.

GAINS ON SALES OF UTILITY PROPERTY

Q: WHAT IS THE COMMISSION'S POLICY REGARDING GAINS ON SALES OF UTILITY PROPERTY?

A: The Commission's policy has been to amortize any gains from sales of utility property as offsets to revenue requirements over a five-year period.

Q: HAS PEF HAD ANY GAINS ON SALES OF UTILITY PROPERTY THAT SHOULD BE AMORTIZED AS AN OFFSET TO THE TEST YEAR REVENUE REQUIREMENT?

A: Yes. PEF recently closed on its sale of the distribution system in Winter Park to the City of Winter Park, which has established a municipal electric utility system.

Q: DID PEF INCLUDE ANY GAINS AS AN OFFSET TO THE TEST YEAR REVENUE REQUIREMENT?

A: No.

Q: WHAT WAS PEF'S CLAIMED REASON FOR FAILING TO AMORTIZE THE WINTER PARK GAIN?

A: As PEF explained in its response to FRF Interrogatory No. 43:

> The impact from the sale of utility assets to Winter Park was not included in the filing because the date on which the purchase would be consummated and operational control would be transferred had not been established at the time of filing, and that date still has not been established with certainty at the time of providing this answer.

Q: IS THIS A VALID REASON FOR PEF TO EXCLUDE THE GAIN FROM THE WINTER PARK SALE IN CALCULATING ITS REVENUE REQUIREMENTS IN THIS CASE?

A: No. Although PEF claimed the date had still not been established with certainty at the time of providing the answer, the Winter Park sale closed on June 1, 2005—26 days before PEF's response to FRF Interrogatory No. 43 was filed. Additionally, on May 31, the Commission approved Winter Park's new electric tariffs. In its order approving those tariffs, issued on June 13, 2005, the Commission noted that the City of Winter Park had purchased PEF's distribution system in the City. Further, PEF's failure to amortize the gain in the Test Year is not excused by its lack of certainty of the purchase date.

Q: SHOULD PEF BE REQUIRED TO ESTIMATE THE GAIN AND AMORTIZE IT AS AN OFFSET TO THE TEST YEAR REVENUE REQUIREMENTS?

A: Yes.

Q: HAS PEF PROVIDED A CALCULATION OF THE GAIN?

A: No. In its response to FRF's Interrogatory No. 21, PEF indicated that the gain or loss resulting from the sale has not yet been quantified.

Q: WHAT IS THE MAGNITUDE OF THE GAIN EXPECTED FROM THE SALE?

A: The arbitration award indicated that the value of PEF's distribution assets was approximately $9 million on a Replacement Cost Less Depreciation valuation. This would be greater than PEF's original cost less depreciation on which a gain would be calculated. This amount was later adjusted to $8.2 million. The total purchase price, as set forth in the Transfer Agreement, was $41,718,447, broken down as follows:

Equipment and fixtures	$ 8,218,447
Stranded costs	$ 7,689,000
CWIP true-up	$ 2,800,000
Half Joint-Use Attachment Inventory	$ 15,000
Real Estate and Easements	$10,000,000
Going Concern Value	$12,000,000
Separation and Reintegration	$ 996,000
Total	$41,718,447

Eliminating the separation and reintegration costs and the CWIP true-up leaves a net purchase price of $37,922,447. PEF has not provided its net investment in assets sold to Winter Park; however, a reasonable, and even conservative, estimate can be made for purposes of determining the magnitude of the gain that was realized by PEF on the sale. As explained earlier, the original $9 million value assigned to the equipment and facilities was based on replacement cost less depreciation. Given the age of the facilities and the escalation associated with replacement cost calculations, the net book value is likely to be significantly less than the $9 million replacement cost less depreciation. In fact, the 2004 Handy Whitman Index of Public Utility Construction Costs shows that the costs of total distribution plant in the South Atlantic region rose 26.4% from 1994 to 2004. While the age and condition of the Winter Park system suggest an average life greater than 10 years, I have used 10 years as a very conservation assumption. Therefore, the original cost less depreciation of the Winter Park facilities is most likely less than $7.1 million. In addition to the equipment and facilities, the arbitration award allowed PEF to receive $10 million for land and easements. This was a fair market valuation and was not based on PEF's actual investment in the land and easements. A review of PEF's 2004 FERC Form 1 shows that its investment in Account 360, distribution land and land rights, was only $21.7 million for the entire system as of December 31, 2004. Therefore, for purposes of this estimate, I have again, conservatively (in PEF's favor) assumed an investment of $1 million in land and land rights in Winter Park. Assuming a net book value of $8.1 million would indicate a gain of approximately $29.8 million. The resulting impact to Test Year revenue requirements would be 1/5 of the gain, or $5.96 million.

Q: SHOULD THE COMMISSION BASE THE AMORTIZATION ON PEF'S ACTUAL GAIN ON THE WINTER PARK SALE?

A: Yes, however, PEF has not provided that information to date. I have presented this analysis to show the magnitude of the reduction in revenue requirement that should be provided to ratepayers. If PEF provides calculations of the gain, FRF reserves the right to review and comment on those calculations at that time.

Q: DO YOU HAVE ANY OTHER CONCERNS REGARDING PEF'S TREATMENT OF ITS SALE TO WINTER PARK?

A: Yes. The recently approved storm damage cost recovery clause included costs for storm damage in Winter Park. Since the Winter Park customers will no longer be included in the retail customer base to which the storm cost recovery charge applies, the costs associated with the Winter Park customers will be, effectively, transferred to PEF's other retail customers. As explained in PEF's response to FRF's Interrogatory No. 46, PEF and Winter Park disagreed on the level of CWIP, including capital costs associated with the 2004 hurricanes, and settled the matter for $2.8 million, which was included in the purchase price. While I do not know whether the $2.8 million settlement was sufficient to protect PEF's other ratepayers from paying for Winter Park assets in the future, it is apparent that PEF's other ratepayers will pay for the Winter Park storm damage costs charged to operating and maintenance expenses. These expenses will be recovered through PEF's Storm Cost Recovery Clause.

Q: HOW COULD THE COMMISSION PROTECT THE REMAINING RETAIL RATEPAYERS?

A: While it is inappropriate for the remaining retail ratepayers to pay for Winter Park's share of the storm damage costs, the amount can be effectively viewed as a reduction to the gain on the sale. In other words, the gain could be viewed as partially repaying the hurricane damage costs, with the remainder attributable to actual gain on the sale. The net amount to be credited to ratepayers would be the same under either circumstance. However, the Commission could protect the remaining retail ratepayers by adjusting its policy, in this instance, to allow the ratepayers to receive the gain over an accelerated basis, beginning January 1, 2006 and continuing for a two-year period. This accelerated amortization would partially offset the added burden that ratepayers are bearing through the implementation of the SCRC. Based on my preliminary calculations of the gain, this adjustment would reduce the Test Year revenue requirements by $14.9 million.

<u>CONSTRUCTION WORK IN PROGRESS</u>

Q: HAS THE COMPANY INCLUDED CONSTRUCTION WORK IN PROGRESS ("CWIP") IN RATE BASE?

A: Yes. As shown on Schedule B-1, the Company has included $82.105 million of CWIP in rate base.

Q: SHOULD CWIP BE INCLUDED IN RATE BASE?

A: No. In past decisions, the Commission has evaluated the need for including CWIP in rate base by determining the amount needed for the Company to maintain financial integrity. The main factor used to measure financial integrity has been interest coverage. On page 20 of his testimony, Dr. Vander Weide set forth the S&P financial guidelines for an A-rating. As shown on Table 2 of his testimony, the interest coverage ratio guidelines for an A-rating are between 3.8 x and 4.5 x. This means that, to achieve an A-rating, a utility should have earnings before income taxes between 3.8 and 4.5 times its interest expense. As shown on Schedule D-9, PEF has indicated Test Year interest coverage ratios (excluding AFUDC) of 5.04 times at present rates and 6.77 times at proposed rates. As shown on Exhibit__(SLB-7), removing CWIP from rate base, and reducing revenues and net income accordingly, reduces the Test Year interest coverage ratio at proposed rates from 6.77 to 6.67 times, yielding a reduction of 0.1 times. The Test Year interest coverage ratio at present rates drops from 5.04 times to 4.94 times, which is still comfortably above the high end of the range needed for an A-rating. Since PEF's EBIT interest coverage is greater than the level needed for an A rating, even without CWIP in rate base, PEF's CWIP should be removed from rate base.

Q: WHAT IS THE REVENUE IMPACT OF REMOVING THE CWIP FROM THE TEST YEAR RATE BASE?

A: The revenue impact of removing CWIP from rate base is $12.721 million. ($82.105 million x 9.4939% x 1.6320).

BAD DEBT EXPENSE

Q: WHAT IS THE LEVEL OF BAD DEBT EXPENSE THE COMPANY IS CLAIMING FOR THE TEST YEAR?

A: The Company is using a bad debt factor of 0.1743% for the Test Year. When applied to the Test Year revenues at current rates of $3,612,553,000, the Test Year write-offs are $6.298 million, as shown on Schedule C-11.

Q: IS THIS AN APPROPRIATE, FAIR, AND REASONABLE VALUE TO BE USED IN SETTING RATES IN THIS CASE?

A: No. The bad debt factor projected by the Company is greater than the actual bad debt experience over the last four years, resulting in an overstatement of bad debt expense for the Test Year.

Q: HOW DOES THE TEST YEAR BAD DEBT FACTOR COMPARE TO THE COMPANY'S PREVIOUS WRITE-OFF HISTORY?

A: The Test Year bad debt factor is higher than the level of bad debt incurred during any of the last four years. As shown on Schedule C-11, the bad debt factor ranged from 0.1228% to 0.1700% from 2001 through 2004.

Q: HAS THE COMPANY JUSTIFIED THIS INCREASE IN WRITE-OFFS FOR THE TEST YEAR?

A: No.

Q: WHAT IS AN APPROPRIATE LEVEL OF BAD DEBT EXPENSE TO INCLUDE IN THE TEST YEAR REVENUE REQUIREMENT?

A: Using an average of the bad debt experience from 2001 through 2004 yields a bad debt factor of 0.1444%.

Q: WHAT IS THE REVENUE IMPACT OF REDUCING THE TEST YEAR BAD DEBT FACTOR FROM 0.1743% TO 0.1444%?

A: The use of this factor reduces the Test Year write-offs from $6.298 million to $5.194 million. In addition, reducing the bad debt factor also reduces the revenue expansion factor from 1.63202 to 1.63153. The combined impact of these adjustments is a reduction in the Test Year revenue requirement of $1.162 million. These calculations are shown on Exhibit__(SLB-8).

WORKING CAPITAL

Q: DO YOU HAVE ANY CONCERNS WITH THE AMOUNT OF WORKING CAPITAL PEF HAS INCLUDED IN RATE BASE?

A: Yes. I have several concerns with the amount of Working Capital that PEF has included in rate base. PEF has understated its regulatory liabilities associated with Last Core Nuclear Fuel and End-of-Life ("EOL") Nuclear Materials and Supplies Inventory. These understatements have the direct effect of overstating Working Capital and thus overstating rate base. The Working Capital component of rate base has also been overstated by an improper jurisdictional allocation in the removal of the storm damage reserve that is to be recovered through the Storm Cost Recovery Clause ("SCRC"). In addition, PEF has included the unamortized balance of Rate Case expenses in rate base. The net effect of these Working Capital errors is an increase to the jurisdictional rate base of $21.929 million, resulting in an overstatement of the jurisdictional Test Year revenue requirement of $3.4 million. The Commission should, accordingly, disallow these amounts from rate base and revenue requirements, respectively.

Q: HOW HAS PEF UNDERSTATED ITS REGULATORY LIABILITIES ASSOCIATED WITH LAST CORE NUCLEAR FUEL AND END OF LIFE NUCLEAR MATERIALS AND SUPPLIES INVENTORY?

A: PEF has proposed reduced accruals to its Last Core Nuclear Fuel and EOL Materials and Supplies reserves. While these accruals would reduce the reserve balances for the end of the Test Year, PEF has incorrectly assumed a beginning reserve balance for the Test Year that is significantly less than the actual reserve balances. In accordance with Order No. PSC-02-0055-PAA-EI in Docket Nos. 981246-EI, 001835-EI, 990342-EI, and 991931-EI, PEF has been accruing $1.1 million a year into the Last Core Nuclear Fuel reserve and $1.5 million a year into the End of Life Materials and Supplies Inventory reserve. As shown on Schedule B-21, Page 6 of 6, the balances in the Last Core Nuclear Fuel and EOL Materials and Supplies reserves at December 31, 2004 were $4.4 million and $6 million, respectively. With the accruals continued through 2005, the balances at December 31, 2005 will be $5.5 million and $7.5 million; however, as shown on Schedule B-21, Page 3 of 6, the amounts PEF included in the calculation of the reserve balances at December 31, 2005 were only $1.459 million and $4.217 million for the Last Core and EOL reserves, respectively.

Q: DID PEF REVISE SCHEDULE B-21?

A: Yes. PEF revised its Schedule B-21 in response to FRF Interrogatory No. 55; however, the revised Schedule B-21 is still in error. As shown on Revised Schedule B-21, the beginning balance in the Last Core Nuclear Fuel reserve was revised from $1.459 million to $4.217 million. This is still $1.3 million less than the projected December 31, 2005 reserve balance based on continued accruals of $1.1 million prior to the implementation of revised base rates. In addition, the $4.217 million is a reduction in the Last Core Nuclear Fuel reserve account from the December 31, 2004 balance, thus implying actual charges against the account, which should not occur until the time the nuclear unit is retired.

Q: WHAT BEGINNING BALANCE DID PEF ASSUME FOR THE EOL RESERVE IN ITS REVISED SCHEDULE B-21?

A: The beginning balance of the EOL reserve for the Test Year was revised from $4.217 million to $5.750 million. Even with this adjustment, the EOL reserve is $1.75 million less than it should be at December 31, 2005 and is even $250,000 less than it actually was at December 31, 2004. Again, this implies no accruals for 2005 and, in fact, results in charges against the account. The purpose of the EOL reserve is to pay for materials and supplies on hand at the nuclear facility at the time of retirement. There is no reason for charges against the reserve until that time.

Q: ARE THERE ANY OTHER ERRORS IN THE DEVELOPMENT OF SCHEDULE B-21?

A: Yes. Aside from the errors in the calculation of the beginning balances, PEF has assumed no contributions to the reserves for the Test Year. This is inconsistent with the charges included in the Test Year expenses.

Q: WAS THIS ERROR CORRECTED IN THE REVISED SCHEDULE B-21?

A: No. In the Revised Schedule B-21, PEF assumed an annual accrual of $1.0 million for the Last Core Nuclear Fuel reserve and $1.5 million for the EOL

Materials and Supplies reserve. These accruals were then offset by charges against the reserves, resulting in no change to the reserve for the Test Year.

Q: WHAT WERE THE ACCRUALS FOR THE TEST YEAR?

A: PEF has included accruals of $764,000 and $681,000 for the Last Core Nuclear Maintenance and EOL Materials and Supplies reserves, respectively. These amounts should be added to the reserves in the Test Year, thus increasing the regulatory liability and reducing rate base.

Q: DID PEF MODIFY ITS REVENUE REQUIREMENT BASED ON ITS REVISED SCHEDULE B-21?

A: No. In its response to FRF's Interrogatory No. 55, PEF claimed that the net effect of the change does not impact the total rate base as reflected on Schedule B-1.

Q: DO YOU AGREE WITH PEF'S CONCLUSION THAT THE CHANGE DOES NOT IMPACT RATE BASE?

A: No. A review of PEF's Working Capital schedules shows that the Working Capital component includes the balances in Accounts 228.1 through 228.4. Therefore, any understatement of the regulatory liability has been carried forward into rate base.

Q: HAS PEF PROVIDED ANY ADDITIONAL INFORMATION ON THE LAST CORE NUCLEAR FUEL AND EOL MATERIALS AND SUPPLIES BALANCES?

A: Yes. In response to OPC's Interrogatory No. 3, PEF provided a detailed trial balance showing expected balances as of December 31, 2005. As shown in that response, PEF assumed end-of-year balances of $4,675,009 and $6,375,000 for the Last Core Nuclear Fuel and EOL Materials and Supplies, respectively. These balances assume 2005 accruals of only $275,000 for Last Core Nuclear Fuel and $375,000 for EOL Materials and Supplies, which are significantly less than the amounts actually accrued in accordance with Order No. PSC-02-0055-PAA-EI.

Q: HAVE YOU CALCULATED CORRECTED AVERAGE BALANCES FOR THE LAST CORE NUCLEAR FUEL AND EOL MATERIALS AND SUPPLIES BALANCES?

A: Yes. The corrected reserve balances for the Test Year would be as shown in the table below:

Account	Beginning Balance	Test Year Accruals	Ending Balance	Average Balance
Last Core Nuclear Fuel	$4,400,000	$764,000	$5,164,000	$4,782,000
EOL Mat. & Supplies	$7,500,000	$681,000	$8,181,000	$7,840,500
Total	$11,900,000	$1,445,000	$13,345,000	$12,622,500

Q: WHAT IS THE IMPACT OF ADJUSTING THE LAST CORE AND EOL MATERIALS AND SUPPLIES RESERVE BALANCES ON PEF'S TEST YEAR REVENUE REQUIREMENT?

A: As explained earlier in my testimony, the Company has included $1.459 million and $4.217 million in the Test Year rate base for Last Core Nuclear Fuel and EOL Materials and Supplies, respectively. The total balance included in Working Capital for the Test Year was thus $5.676 million, which is $6.947 million less than the actual Test Year reserve balances of $12.623 million. The rate base should thus be reduced by $6.947 million. The Test Year revenue impact of this adjustment is $1.076 million.

Q: HOW DID THE COMPANY ERR IN REMOVING THE STORM COST RECOVERY CLAUSE REGULATORY ASSET FROM WORKING CAPITAL?

A: As shown on Schedules B-21 and B-17, Page 2 of 3, the Company has removed $139 million from its working capital associated with amounts that will be recovered through the SCRC. While this removal is appropriate since the SCRC includes the addition of interest charges, PEF has incorrectly allocated a portion of this amount to the wholesale jurisdiction, resulting in a credit to Working Capital of only $126.3 million. In its response to FRF Interrogatory No. 59, PEF provided a breakdown of the Test Year Other Regulatory Assets. On that response, PEF indicated that the Regulatory Asset associated with the retail SCRC is $139 million and the Regulatory Asset associated with the wholesale storm damage is $11.9 million. Therefore, the full $139 million should be deducted from the jurisdictional rate base.

Q: WHAT IS THE REVENUE IMPACT OF THIS ADJUSTMENT?

A: This adjustment would decrease rate base by $12.732 million, resulting in a reduction in the Test Year revenue requirement of $1.973 million.

Q: WHAT OTHER ADJUSTMENTS SHOULD BE MADE TO WORKING CAPITAL?

A: Based on previous Commission precedent, the unamortized balance of rate case expenses should be excluded from rate base. This adjustment reduces the rate base by $2.25 million, with a corresponding $348,618 reduction in the Test Year revenue requirement.

Q: DID ANY OF THESE ADJUSTMENTS AFFECT THE ACCUMULATED DEFERRED INCOME TAXES INCLUDED IN THE CAPITAL STRUCTURE?

A: Apparently not. As shown on Schedule C-22, PEF adjusted its deferred income taxes in the Test Year for $2.5 million associated with the Last Core and EOL reserve accruals. While this amount should have been $2.6 million, the adjustment shows that PEF was assuming an increase in the associated Account 190 deferred income tax balances. As shown on Schedule D-1b, PEF also adjusted its deferred income taxes to remove the effects of storm costs. Lastly, while PEF made a pro-rata adjustment to the capital structure for the $2.25 million average rate base associated with rate case expenses, it did not make a corresponding adjustment to deferred income taxes; therefore, removal of the rate base item would not require removal of an associated deferred income tax.

RATE CASE EXPENSES

Q: WHAT IS THE TOTAL REVENUE REQUIREMENT INCLUDED IN THE TEST YEAR FOR RATE CASE EXPENSES?

A: The Company has included $1.5 million of rate case expenses in the Test Year, along with a regulatory asset of $2.25 million in working capital. The total revenue requirement included in the Test Year associated with rate case expenses is thus $1.849 million as shown on Exhibit__(SLB-9).

Q: HOW DID THE COMPANY DETERMINE THE LEVEL OF RATE CASE EXPENSES AND THE REGULATORY ASSET THAT IT INCLUDED IN THE TEST YEAR?

A: As shown on Schedule C-10, the Company is estimating $3 million in total expenses to be incurred in this rate case. The Company is then proposing to defer these expenses and to amortize them over a 2 year period. The $2.25 million working capital component is the average of the beginning and ending Test Year balances of the deferred expenses ($3 million beginning and $1.5 million ending).

Q: IN PREVIOUS PROCEEDINGS, THE COMMISSION HAS ALLOWED UTILITIES TO DEFER AND AMORTIZE RATE CASE EXPENSES. IS THERE ANY REASON TO DISALLOW DEFERRAL AND AMORTIZATION IN THIS CASE?

A: Yes. PEF is already recovering its rate case expenses and its request for deferral and amortization of the rate case expenses should be denied.

As shown in PEF's Surveillance Report for the 12 months ending January, 2005, PEF is earning a 13.45% after-tax return on equity. Even if the entire $3 million of rate case expenses is subtracted from PEF's net operating income on a net-of-tax basis, PEF would still have a return on common equity of 13.36%. Therefore, PEF cannot reasonably claim to be entitled to defer these costs for future recovery in order to have a fair return.

The Commission should thus deny PEF's request to defer the rate case expenses for recovery in the Test Year. Elimination of rate case expenses would reduce the Test Year revenue requirement by $1.5 million. The associated rate base component should also be removed and was addressed in the Working Capital portion of my testimony.

Q: DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR THE COMMISSION REGARDING PEF'S RATE CASE EXPENSES?

A: Yes. In its response to OPC's Interrogatory No. 92, PEF claims that it has proposed a two-year amortization period because "the Company will be adding another Hines unit at the end of 2007 and it is possible that the Company may request another base rate increase at that time." If the Commission allows PEF to defer the rate case expenses and amortize them over a two-year period based on PEF's representation that it is possible that there will be another base rate increase at that time, then the Commission should protect customers from excess amortization. This could be accomplished by requiring PEF to continue accruing the annual rate case expense accrual, thereby creating a regulatory liability to be used against rate case expenses in the next proceeding. This would prevent double payments. For example, in PEF's last rate case, it included $822,000 in annual rate case expenses in the revenue requirement using a two-year amortization period. Since new rates will not be placed in effect until 2006, the amount recovered is in excess of the Company's previous rate case expense estimate.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR RATE CASE EXPENSES.

A: In all cases, the unamortized deferred rate case expenses should be removed from rate base. This adjustment is explained in the Working Capital section of my testimony and reduces the Test Year revenue requirement by $348,618.

The Commission should deny PEF's request for deferral and recovery of rate case expenses in the Test Year. This adjustment would reduce the Test Year revenue requirement by $1.5 million. If the Commission chooses to allow deferral, the Commission should require PEF to book a regulatory liability if the rates are not changed following the amortization period.

STORM DAMAGE ACCRUALS

Q: WHAT IS THE LEVEL OF STORM DAMAGE ACCRUAL THAT PEF IS REQUESTING IN THIS CASE?

A: The Company is requesting a $50 million annual accrual to the storm damage reserve. This is a $44 million increase over the present annual accrual of $6 million.

Q: HAS PEF PERFORMED ANY ANALYSES OF THE EXPECTED ANNUAL UNINSURED STORM DAMAGE COSTS?

A: Yes. PEF engaged ABS Consulting to perform a storm damage study. In that study, ABS has analyzed the average expected annual uninsured costs based on an analysis of historical and random storms to determine an average expected level of damage. ABS then applied estimates from the 2004 storm restoration costs to determine the costs associated with the average expected level of damage. Based on this analysis, ABS concluded that the expected annual uninsured cost to PEF's system is estimated to be $15.2 million.

Q: HAVE YOU REVIEWED PEF'S ACTUAL STORM DAMAGE COSTS?

A: Yes. In exhibit (JP-1) of Mr. Portuondo's testimony submitted November 24, 2004 for Docket No. 041272-EI, the Company provided the annual charges to the reserve for storm damages. Beginning with 1994 and ending with the 2004 season, the Company experienced storm damage in 9 of the 11 years, although some years were negligible in terms of damage. I escalated the costs from each year to 2006 to account for inflation.

Based on PEF's actual experience from 1994 through 2003, the annual average uninsured storm damage cost is $2.252 million. This reflects expected costs for smaller, Category 1 and 2 storms.

Q: WHAT HAS BEEN PEF'S EXPERIENCE REGARDING THE FREQUENCY OF LARGER, CATEGORY 3 TO 5 STORMS?

A: The National Oceanic and Atmospheric Administration reports that there were only seven Category 3 to 5 storms occurring in Northeast and Northwest Florida from 1900 to 2000, or one approximately every 14 years. Progress Energy's website has a breakdown of major storms affecting its service territories. On that website, the only major storms listed for the PEF service territory are those storms that occurred in 2004. Based on this information, I have assumed that PEF will experience a Category 3 through 5 storm approximately every 10 years, as shown on Exhibit__(SLB-10), page 1 of 3.

Q: WHAT WAS THE AVERAGE LOSS INCURRED FOR THE 2004 STORMS?

A: Based on PEF's total damage of $366 million, the 2004 storms would be expected to cost $388.3 million in 2006 dollars. Although this was the sum for four storms, I have calculated the average storm costs based on only three storms. This approach was taken because it is impossible to identify the actual costs incurred for any one storm and Hurricane Ivan did not have a major impact on PEF's service territory. The average cost for a Category 3 to 5 storm in 2006 dollars would thus be $129.43 million. Assuming one major storm each 10 years, the annual average cost would be $12.943 million.

Q: BASED ON ACTUAL HURRICANE HISTORY AND PEF DAMAGES, WHAT WOULD BE THE EXPECTED ANNUAL STORM DAMAGE COSTS?

A: Combining the average annual storm damage from the Category 1 and 2 storms with the average annual storm damage from the Category 3 through 5 storms provides an annual average storm damage of $15.2 million—the same annual average estimate derived by ABS Consulting.

Q: DOES THE COMPANY NEED TO ACCRUE $50 MILLION A YEAR IN ANTICIPATION OF ANOTHER MAJOR STORM?

A: No. PEF is protected from the costs associated with storm damage through the Commission's practice of allowing the utility to seek recovery of any storm damage costs in excess of the reserve. This practice was confirmed with the Commission's allowance of the SCRC for the unprecedented 2004 hurricane damage costs in Docket No. 041272-EI. The recently passed securitization legislation also provides an added layer of protection for PEF and other utilities in

Florida. Therefore, it is not necessary for the storm damage reserve to cover 100% of potential storm damage costs.

Q: WHAT LEVEL OF STORM DAMAGE ACCRUAL ARE YOU RECOMMENDING IN THIS CASE?

A: I am recommending that PEF be allowed to increase its annual storm damage accrual to the expected annual average storm damage of $15.2 million. This level of accrual is 2.3 times the highest annual storm damage incurred from 1994 through 2003 and is 6.7 times greater than the average annual storm damage incurred during that same period. Assuming the average annual storm damage of $2.25 million over a ten-year period, this would allow the reserve balance to increase by $12.75 million a year. While no one can predict when PEF's service territory will experience another major storm, this level of accrual, combined with PEF's ability to seek recovery of any storm damages in excess of reserve balances through a SCRC, provides the protection PEF needs. This level of accrual also protects ratepayers, who are already burdened by the SCRC for the extraordinary 2004 storm damage costs, on top of PEF's existing rates that have produced and are continuing to produce extraordinary, excessive returns to PEF's shareholders.

Q: WHAT IS THE IMPACT OF REDUCING THE STORM DAMAGE ACCRUAL FROM THE $50 MILLION REQUESTED BY THE COMPANY TO THE $15.2 MILLION EXPECTED ANNUAL AVERAGE STORM DAMAGE?

A: As shown on Exhibit__(SLB-10), page 2 of 3, this adjustment reduces the jurisdictional Test Year revenue requirement by $31.125 million. This adjustment takes into account the $34.8 million reduction in the annual accrual and the corresponding decrease in Account 228, which has the effect of increasing rate base.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH PEF'S STORM DAMAGE RESERVE?

A: Yes. PEF has understated its year-end balance in the storm reserve. In addition, PEF has understated the tax impact of its requested increase to the annual accrual.

Q: HOW DID PEF UNDERSTATE ITS YEAR-END BALANCE IN THE STORM RESERVE?

A: As shown on Schedule B-21, PEF has assumed a beginning balance of $6.515 million, with an accrual of $6 million and an ending balance of $12.015 million (prior to PEF's requested $44 million adjustment in annual accrual). This mathematical error understates the year-end balance by $500,000 and the average Test Year reserve balance by $250,000. This error overstates the jurisdictional Test Year revenue requirement by $37,536. These calculations are shown on Exhibit__(SLB-10), page 3 of 3.

Q: HOW DID PEF UNDERSTATE THE TAX IMPACTS ASSOCIATED WITH ITS REQUESTED INCREASE IN THE ACCRUAL TO THE STORM RESERVE?

A: PEF has assumed a jurisdictional factor of 96.949% for the storm damage accrual. However, as shown on Schedule C-3, page 1, the net of tax storm reserve adjustment is allocated 99.796% to the retail jurisdiction. A review of the increase to the reserve and the associated income taxes shown on Schedule C-2, page 3 shows that the increase to the reserve is allocated on the 96.949% factor;

however, the increase in net operating income for the income tax deduction was calculated at 36.77%, rather than PEF's tax rate of 38.575%. This error results in an overstatement of the jurisdictional Test Year revenue requirements of $1.256 million, as shown on Exhibit__(SLB-10), page 3 of 3.

Q: IS THIS ADJUSTMENT STILL APPLICABLE IF THE COMMISSION ADOPTS YOUR RECOMMENDED ADJUSTMENT TO THE ANNUAL STORM DAMAGE ACCRUAL?

A: Yes. The $31.125 million jurisdictional Test Year revenue impact of reducing the annual accrual to $15.2 million was calculated assuming that the taxes were correctly calculated in PEF's filing; therefore, this adjustment would still be required.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

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

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

DATED THIS 12th day of September, 2005.

Jane Faurot

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