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July 13, 2005

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Blanca Bayo, Director
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Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition of Progress Energy Florida for a Rate Increase, Docket No. 050078-EI

Dear Ms. Bayo:

Enclosed for filing are the original and fifteen copies of the prefiled direct testimony and exhibits of Sheree L. Brown, submitted on behalf of the Florida Retail Federation in the above-styled docket. I will appreciate your confirming receipt of this filing by stamping the attached copy thereof and returning same to my attention.

As always, my thanks to you and to your professional Staff for your kind and courteous assistance. If you have any questions, please give me a call at (850)681-0311.

Cordially yours,

Robert Scheffel Wright

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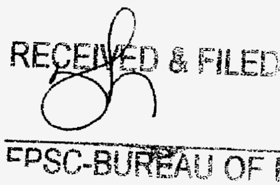

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Progress Energy Florida's Petition for Increase in Base Rates

DOCKET NO. 050078-EI

Submitted for Filing: July 13, 2005

DIRECT TESTIMONY OF SHEREE L. BROWN ON BEHALF OF THE FLORIDA RETAIL FEDERATION

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ON BEHALF OF THE
FLORIDA RETAIL FEDERATION

1 **FPSC DOCKET NO. 050078-EI**
2
3 **IN RE: PROGRESS ENERGY FLORIDA'S PETITION**
4 **FOR APPROVAL OF INCREASE IN BASE RATES**
5
6 **DIRECT TESTIMONY OF SHEREE L. BROWN**
7
8 INTRODUCTION

9 Q: PLEASE STATE YOUR NAME AND OCCUPATION.

10 A: My name is Sheree L. Brown and I am the President and Managing Principal of
11 Utility Advisors' Network, Inc., located at 530 Mandalay Rd., Orlando, Florida
12 32809.

13 Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
14 EXPERIENCE.

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

18 I have been providing utility consulting services to municipal, cooperative,
19 county, and institutional utilities and industrial and commercial consumers since
20 1981. My work has primarily focused in the areas of regulatory affairs, revenue
21 requirement and costs of service, rates and rate design, deregulation and stranded
22 costs, valuation and acquisition, feasibility studies, and contract negotiations.

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

1 A: Yes. I have participated in several proceedings before the FPSC, most recently
2 including the Progress Energy Florida ("PEF") storm surcharge case, Docket No.
3 041272-EI; the last Florida Power & Light Company ("FPL") general rate
4 proceeding, Docket No. 001148-EI; the last PEF general rate proceeding, Docket
5 No. 000824-EI; and in the 2003 Fuel Cost Recovery Proceedings, Docket No.
6 030001-EI, on issues relating to Tampa Electric Company's fuel costs. I have
7 testified before the Federal Energy Regulatory Commission ("FERC"), the
8 Arkansas Public Service Commission, the Council of the City of New Orleans,
9 the Illinois Commerce Commission, the Louisiana Public Service Commission,
10 the Massachusetts Department of Telecommunications & Energy, the Minnesota
11 Public Utilities Commission, the New Hampshire Public Utilities Commission,
12 the North Carolina Utilities Commission, and the Texas Public Utilities
13 Commission. I have prefiled testimony and exhibits in FPL's current general rate
14 case, Docket No. 050045-EI. I have also presented arbitration reports and live
15 testimony in the Circuit Court of the Ninth Judicial Circuit in and for Orange
16 County, Florida, and in the Circuit Court of the Eighteenth Judicial Circuit in and
17 for Seminole County, Florida in PEF's recent arbitrations regarding acquisition of
18 electric distribution facilities.
19 My testimony has addressed a wide range of regulatory and utility-related issues,
20 including revenue requirement issues, cost of service, cost allocation, rate design,
21 terms and conditions of service, merger impacts, utility valuations, stranded costs,
22 and deregulation. My resumé and a listing of my testimony experience is
23 included as Appendix A to my testimony.

1 Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

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

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

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

9 SUMMARY

10 Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

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

18 ▪ PEF has overstated its Test Year employees, resulting in an overstatement
19 of the Test Year jurisdictional revenue requirement of $2.235 million.

20 ▪ PEF has included a portion of capitalized payroll taxes in the Test Year
21 expenses, resulting in an overstatement of jurisdictional revenue
22 requirement of $6.095 million.

1 ▪ PEF has overstated its base pay expense ratio, resulting in an additional
2 overstatement of the Test Year jurisdictional revenue requirement by
3 $6.626 million.
4 ▪ The Company erred in removing non-utility equity from its capital
5 structure. Correction of this error reduces the Test year revenue
6 requirement by $611,000. Based on PEF's admission of this error, I have
7 assumed the correction as a "given" and all revenue impacts stated herein
8 are based on the changes from the corrected requested rate increase of
9 $204.945 million.
10 ▪ PEF's capital structure adjustment for its 1997 Crystal River 3 outage cost
11 is no longer necessary to maintain an appropriate equity ratio and should
12 be discontinued. This adjustment reduces the Test Year revenue
13 requirement by $9.502 million.
14 ▪ PEF is requesting a 50 basis-point adder to its requested return on equity.
15 This adder is not necessary as a performance bonus and does not provide
16 correct incentives for future performance and should thus be denied.
17 Elimination of this adder from PEF's requested return on equity reduces
18 the Test Year revenue requirement by $21.9 million.
19 ▪ PEF's requested rate of return on equity has also been increased by 90
20 basis points based on an incorrect assumption of additional financial risk.
21 Elimination of this 90 basis point adder further reduces the Test Year
22 revenue requirement by $39.344 million.

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

1 - Based on actual historical experience, PEF has overestimated its bad debt
2 for the Test Year. Reducing the bad debt factor to reflect historical
3 averages reduces the Test Year revenue requirement by $1.162 million.
4 - In removing the retail jurisdiction storm damage asset from rate base, due
5 to its inclusion in the Storm Damage Cost Recovery ("SDCR") clause,
6 PEF allocated a portion of the asset to the wholesale jurisdiction. The rate
7 base elimination was thus understated by $12.732 million. Correcting the
8 allocation results in a reduction in the Test Year jurisdictional revenue
9 requirement of $1.973 million.
10 - PEF has incorrectly stated the balances in its Last Core Nuclear Fuel
11 ("LCNF") and End-of-Life Materials and Supplies ("EOL") reserves,
12 thereby overstating the jurisdictional rate base. Correcting the reserve
13 balances reduces the Test Year jurisdictional revenue requirement by
14 $1.076 million.
15 - PEF has included $2.25 million in working capital associated with
16 deferred rate case expenses. Based on past Commission precedent, this
17 account should be removed from rate base. The impact of removing this
18 account from rate base is a reduction of $348,618 in the Test Year
19 jurisdictional revenue requirement.
20 - PEF has included $1.5 million for rate case expenses in the Test Year,
21 based on total deferred rate case expenses of $3 million, amortized over a
22 two-year period. Based on PEF's current earnings levels, it is

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

3 ▪ PEF has included $82.105 million in rate base for Construction Work in
4 Progress ("CWIP"). A review of PEF's interest coverage ratios, with and
5 without CWIP in rate base, shows that PEF's ratios are excellent even
6 without CWIP in rate base. Therefore, CWIP should be removed from
7 rate base and the Test Year retail jurisdiction revenue requirement should
8 be reduced by $12.721 million.

9 ▪ PEF's request for an additional $44 million per year in storm damage
10 accrual is excessive, particularly in light of the Commission's recent
11 decision in PEF's 2004 storm cost recovery docket and the securitization
12 legislation enacted and signed into Florida law this year. An increase in
13 the annual storm damage accrual to $15.2 million a year would be
14 sufficient to protect the Company without placing an undue burden on
15 ratepayers. This adjustment reduces the retail jurisdiction Test Year
16 revenue requirement by $31.125 million.

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

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

19 A: PEF initially requested a $206.6 million increase in base rates, effective January
20 1, 2006. As noted above, based on PEF's admission of its erroneous treatment of
21 non-utility equity, I am assuming that PEF is actually requesting a base rate
22 increase of $204.945 million per year. PEF's request includes revenues sufficient
23 to produce a 12.8% after-tax return on equity, including a 50 basis point "adder"

1 as an incentive or reward and a 90 basis point adder based on PEF's claim that it
2 has more financial risk than the Company's proxy utility group..
3 Q: IS PEF'S REQUESTED BASE RATE INCREASE OF $204.9 MILLION
4 REASONABLE?
5 A: No. PEF's proposed Test Year revenue requirement includes numerous items that
6 have been overstated, resulting in proposed rates that are not fair, just, or
7 reasonable. I will address each of these issues in my testimony.
8 <u>LABOR EXPENSES</u>
9 Q: DO YOU HAVE ANY CONCERNS REGARDING PEF'S TEST YEAR
10 LABOR EXPENSES?
11 A: Yes. The Company has overstated its level of employees in developing its Test
12 Year payroll and benefits expenses.
13 Q: HOW DID THE COMPANY OVERSTATE ITS LEVEL OF TEST YEAR
14 EMPLOYEES?
15 A: The Company had 4,084 employees at the end of 2004. By the end of April,
16 2005, PEF had reduced its employees to 4,065. As explained by PEF's Witness,
17 Mr. Portuondo, the Company has implemented a reorganization plan which
18 includes voluntary severance and is expected to result in a net reduction of 103
19 positions over 2005 and into early 2006. In its response to OPC's Interrogatory
20 No. 22, PEF stated that no positions were to be added in 2005 and 2006.
21 However, as shown on Schedule C-35, PEF actually included an additional 46
22 positions in the 2006 Test Year, prior to making the adjustment to remove 103 net

1 positions from the reorganization. This overstates the number of employees and,

2 thus, PEF's labor expenses.

3 Q: SHOULD THE COMMISSION ADJUST PEF'S TEST YEAR PAYROLL AND

4 BENEFITS EXPENSES TO REFLECT THE ELIMINATION OF THE EXTRA

5 46 POSITIONS?

6 A: Yes. The number of positions that should be included in the Test Year payroll

7 and benefits expense estimates should be equal to the December 30, 2004 level of

8 employees. This would comport with the Company's indication that there are no

9 positions to be added for 2005 and 2006. This adjustment reduces the

10 jurisdictional Test Year revenue requirement by $2.235 million as shown on

11 Exhibit__(SLB-1).

12 Q: DO YOU HAVE ANY OTHER CONCERNS WITH THE LEVEL OF

13 PAYROLL AND BENEFITS EXPENSES INCLUDED IN THE TEST YEAR

14 REVENUE REQUIREMENT?

15 A: Yes. PEF has overstated the percentage of base payroll and payroll taxes charged

16 to expenses, as opposed to being capitalized. By overstating the expense ratios,

17 PEF has overstated the Test Year revenue requirement. In determining the

18 appropriate Test Year revenue requirement, the Commission should correct these

19 assumptions.

1 Q: PLEASE DESCRIBE HOW PEF HAS OVERSTATED THE PORTION OF ITS

2 PAYROLL TAXES THAT IS INCLUDED IN TEST YEAR EXPENSES.

3 A: In the Commission Staff's Interrogatory No. 90, Staff asked PEF to explain why

4 the percentage of payroll taxes charged to operating expense had increased from

5 60% in 2004 to over 83% in the Test Year. The Company's response was:

6 Payroll taxes follow payroll dollars and are charged to operating expense

7 or capital on the same basis as the actual payroll. The amount charged to

8 operating expense varies from year to year depending on the types of

9 projects undertaken. In 2004, a greater percentage of payroll was

10 associated with projects that were not charged to operating expense.

11 However, PEF provided the percentage of payroll charged to expense for the Test

12 Year in response to FRF Interrogatory No. 26. As shown in that response, 57% of

13 base payroll was charged to expense—not 83% as implied in the response to

14 Staff Interrogatory No. 90.

15 Further, in its response to FRF Interrogatory No. 26, the Company shows an

16 expense ratio of 64% for FICA and unemployment, with a total of $16.040

17 million expensed—although Schedule C-20 shows a total of $19.574 million

18 expensed.

19 Q: SHOULD THE COMMISSION ADJUST THE LEVEL OF PAYROLL TAXES

20 INCLUDED IN THE JURISDICTIONAL TEST YEAR REVENUE

21 REQUIREMENT?

22 A: Yes. As shown on the response to OPC's Interrogatory No. 26, 58% of total

23 payroll is expensed in the Test Year. Based on the total payroll taxes of

1 $23,363,155, the amount expensed should thus be $13,550,630. Using the
2 jurisdictional allocation factor of 92.421% as shown on Schedule C-20 provides a
3 retail jurisidictional payroll tax amount of $12,523,628. Schedule C-1 shows that
4 a portion of the expense is recovered through the ECCR and ECRC clauses. The
5 specific amount charged to these clauses associated with the payroll taxes is
6 $528,572 as shown in PEF's response to FRF's Interrogatory No. 16. After
7 removal of the ECCR and ECRC clause recoveries of $528,572, the remaining
8 jurisdictional expense to be recovered through base rates is $11,995,056.

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

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

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

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

1 Interrogatory No. 16 shows a significant increase in charges to operating and
2 maintenance expense accounts, as compared to the historical years. For example,
3 in 2002 through 2004, the amount of base payroll charged to Account 107, CWIP,
4 ranged from $64.2 million to $69.6 million, while the amount allocated in the Test
5 Year is only $54.1 million. The base payroll charged to Accounts 590 to 598 in
6 2002 through 2004 ranged from $2.6 million to $3.3 million, yet the amount
7 allocated in the Test Year is $17.0 million. The amount of base payroll expensed
8 for each year from 2002 through the Test year was provided in PEF's response to
9 OPC's Interrogatory No. 26. As shown in that response:

10

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%

11
12 Even using the highest expense ratio actually experienced in the previous three-
13 year period would reduce the amount expensed in the Test Year from $156.1
14 million to $148.7 million. This assumption has thus caused an increase in Test
15 Year expenses of $7.3 million.
16 Q: WILL PEF BE REQUIRED TO MAINTAIN THIS EXPENSE RATIO DURING
17 THE ACTUAL PERIOD IN WHICH BASE RATES ARE IN EFFECT?
18 A: No. Therefore, to the extent this ratio is overstated, the effect would be a double-
19 recovery from ratepayers. This would occur if the expenses are actually
20 capitalized, then recovered from ratepayers at a later date through amortization or
21 depreciation of the capitalized items.

1 Q: WHAT IS YOUR RECOMMENDATION REGARDING THE LABOR AND
2 BENEFITS EXPENSE RATIO TO BE USED IN THE TEST YEAR?
3 A: The Commission should adjust the base pay expense ratio based on historical
4 experience. Understanding that there may be differences from year to year and
5 that the ratio in 2004 may have been affected by the hurricanes, I would
6 recommend a reduction in the expense ratio based on the highest ratio
7 experienced over the three-year period from 2002 through 2004. The highest
8 ratio occurred in 2002, with 54.5% of base pay capitalized. This adjustment is
9 shown on Exhibit__(SLB-2) and reduces the jurisdictional Test Year revenue
10 requirement by $6.626 million.
11
12 CAPITAL STRUCTURE
13 Q: DID PEF MAKE ADJUSTMENTS TO ITS CAPITAL STRUCTURE IN THIS
14 CASE?
15 A: Yes. As explained by PEF's Witness, Mr. Sullivan, PEF has modified its capital
16 structure to reflect several adjustments. These adjustments included an equity
17 adder for off-balance sheet obligations, an equity adder for non-utility equity, and
18 an adjustment to equity and long-term debt for the Crystal River 3 ("CR3")
19 outage costs.
20 Q: WHY DID PEF INCLUDE AN EQUITY ADDER FOR NON-UTILITY
21 EQUITY?
22 A: This adjustment was simply an error in calculating the capital structure. As PEF
23 explained in its response to White Springs' Interrogatory No. 9, the non-utility
24 equity should have been subtracted from equity, rather than added.

1 Q: WHAT IS THE IMPACT OF THIS ERROR?

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

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

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

1 adjustment to its equity to allow the equity ratio to fall within the range once the
2 rating agencies make the off-balance sheet adjustment.

3 Q: HOW DID PEF MAKE THE ADJUSTMENT?

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

10 Q: PLEASE EXPLAIN THE CR3 ADJUSTMENT.

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

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

1 continue for a number of years after the four year amortization

2 period has concluded. (Pages 6-7)

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

4 Q: SHOULD THE COMMISSION ALLOW THE COMPANY TO CONTINUE

5 THE CR3 ADJUSTMENT TO THE CAPITAL STRUCTURE?

6 A: No. The Company no longer has the need to make this adjustment in order to

7 meet an appropriate equity ratio.

8 Q: PLEASE EXPLAIN.

9 A: As discussed previously, Mr. Sullivan has indicated that, in order to achieve a

10 single A rating, an appropriate range of leverage ratios for a utility with a business

11 risk profile such as that assigned to PEF is between 42% and 50% . This

12 corresponds to an equity ratio of between 50% and 58%. As explained by Mr.

13 Sullivan:

14 The mid-point of this range is 46% and would be the target leverage ratio

15 for a company seeking to achieve a "single A" credit rating. (Sullivan,

16 page 9)

17 Although Mr. Sullivan indicated that 46% would be the target leverage ratio,

18 implying a target equity ratio of 54%, PEF set a target equity ratio of 55%.

19 Q: IS THIS TARGET RATIO APPLIED TO PEF'S TOTAL CAPITAL

20 STRUCTURE AS DEVELOPED FOR RATEMAKING PURPOSES?

21 A: No. The capital structure analyzed by the rating agencies (the structure for

22 "financial reporting purposes") includes debt, equity, and preferred stock. It does

1 not include the other ratemaking capital structure items, such as accumulated
2 deferred income taxes.
3 Q: WHAT IS PEF'S EQUITY RATIO AFTER MAKING THE CR3
4 ADJUSTMENT?
5 A: After making the CR3 adjustment, PEF's equity ratio for financial reporting
6 purposes is 63.00%. Without the CR3 adjustment, PEF's equity ratio for financial
7 reporting purposes is 53.86%--directly in the middle of the target range of 50% to
8 58% supposedly required by S&P to achieve a single A rating. This equity ratio
9 meets the target requirement noted by Mr. Sullivan on page 9 of his testimony.
10 These calculations are shown on Exhibit__(SLB-3), pages 1 and 2 of 3.
11 Q: IS IT APPROPRIATE TO ALLOW PEF TO CONTINUE THE CR3
12 ADJUSTMENT INTO PERPETUITY DUE TO THE LOSSES IT INCURRED
13 IN 1997 DURING THE EXTENDED CR3 OUTAGE?
14 A: No. As explained by the Commission in Order no. PSC-97-0840-S-EI:
15 However, it should be pointed out that the Company has other
16 means to increase equity including reduction of dividends, parent
17 equity infusion and future earnings. (Page 6)
18 Based on the current capital structure and financial targets attested to Mr.
19 Sullivan, the CR3 adjustment should no longer be allowed. While PEF incurred
20 losses in 1997, it has enjoyed attractive earnings in the intervening years;
21 therefore, this adjustment should not be continued into perpetuity.

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

4 A: Yes. As explained by Mr. Portuondo:

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

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

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

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

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

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

1 Q: PLEASE EXPLAIN HOW THE SUBTRACTION OF THE CR3 "EQUITY" FROM
2 LONG-TERM DEBT PROVIDES PEF WITH AN ADDITIONAL EQUITY BONUS.
3 A: Exhibit__(SLB-3), page 3 of 3, shows the capital structure calculations without
4 the CR3 adjustment to debt. A comparison of the capital structure without the
5 CR3 debt adjustment to the corrected capital structure shown on Exhibit__(SLB-
6 3), page 1 of 3, shows the impact of PEF's adjustment on the equity component of
7 the capital structure. The impact of subtracting the CR3 adjustment from Long-
8 Term Debt is an increase in the equity component of the capital structure from
9 56.72% to 57.72% and an increase in the overall return from 9.43% to 9.49%. By
10 subtracting the CR3 adjustment from long-term debt, PEF also increased the
11 equity ratio for financial reporting purposes from 61.80% to 63.00%. As shown
12 on Exhibit__(SLB-3), page 3 of 3, when applied to PEF's Test Year rate base, the
13 revenue impact associated with PEF's CR3 adjustment to long-term debt is
14 $4.975 million.
15 Q: WHAT IS YOUR RECOMMENDATION IN THIS CASE REGARDING THE
16 CR3 ADJUSTMENT?
17 A: For the reasons stated above, the CR3 adjustment should be removed in its
18 entirety – from both equity and long-term debt -- and the Test Year revenue
19 requirement should be reduced by $9.502 million. If, however, the Commission
20 chooses to allow continuation of the CR3 equity adjustment, the adjustment to the
21 long-term debt component should be eliminated and the Test Year revenue
22 requirement should be reduced by $4.975 million.

1 COST OF CAPITAL

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

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

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

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

1 - It is not a reasonable cost of providing service.

2 - Much of the claimed savings that PEF asserts were provided to
3 ratepayers in Docket No. 000824-EI were, in fact, no savings at all,
4 but rather deferred costs for which PEF is now seeking recovery.

5 - The cost savings that PEF has realized during the term of the 2002
6 settlement in Docket No. 000824-EI have accrued solely and
7 exclusively to PEF's shareholders, through higher profits, and to
8 PEF's employees, through incentive payments. In other words,
9 PEF is now asking for an additional reward over-and-above the
10 substantial bottom-line profits that its shareholders have already
11 enjoyed and in which its customers have not shared.

12 - The proposed adder is not a meaningful incentive for future
13 behavior.

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

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

1 Q: HAVE THE COMPANY'S ACTIONS REALLY YIELDED $125 MILLION IN
2 ANNUAL BENEFITS TO CUSTOMERS?
3 A: No. A review of the Settlement and Stipulation in Docket No. 000824-EI shows
4 that the $125 million rate reduction consisted more of cost deferrals than real
5 savings. Fully one-half of the reduction was associated with the suspension of
6 $62.5 million in depreciation expense. Another $8.733 million was suspension of
7 decommissioning costs. Another $5.27 million was suspension of the fossil
8 dismantlement charges. Therefore, $76.503 million, or 61.2%, of the total
9 "reductions" were merely *deferrals* of costs, not *true* savings. In fact, in this
10 proceeding, customers are already seeing the impact of the deferred depreciation
11 expense which is offsetting the reductions to depreciation expense that would
12 otherwise be enjoyed as a result of the new depreciation study.
13 Q: BUT, HASN'T THE COMPANY SUCCESSFULLY REDUCED OPERATING
14 EXPENSES?
15 A: As will be demonstrated later in my testimony, the Company has successfully
16 reduced certain operating expenses from the levels it claimed in Docket No.
17 000824-EI. These reductions, however, have not been enjoyed by PEF's
18 customers but have, instead, accrued to PEF's shareholders in the form of higher
19 returns on equity. Further, it appears that other projected costs that PEF claimed
20 in Docket No. 000824-EI for service improvements have been deferred and are
21 now showing up again in PEF's current cost projections.

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

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

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

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

1 Q: WHY DOESN'T A RATE OF RETURN ADDER PROVIDE AN INCENTIVE
2 FOR BETTER FUTURE PERFORMANCE?
3 A: Under the current regulated ratemaking treatment, utilities have the incentive to
4 cut costs between rate cases, regardless of the authorized return on equity. A rate
5 of return adder will thus not increase the utility's incentive to achieve cost
6 savings.
7 Q: PLEASE EXPLAIN WHY UTILITIES HAVE THE INCENTIVE TO CUT
8 COSTS BETWEEN RATE CASES.
9 A: Utilities, like any other business, seek to maximize profits. Profits can be
10 maximized by increasing revenues or reducing costs. For utilities, however,
11 revenues are generally not controllable, so utilities focus on cost reductions as a
12 means to maximize profit.
13 Under current regulated ratemaking treatment, there are essentially three
14 components to the development of rates: (a) costs that are passed-through directly
15 to consumers through adjustment clauses, (b) costs that are included in the
16 development of base rates with no markup to the utility, and (c) the fair return on
17 assets invested to serve customers, which is also incorporated into base rates.
18 Regulated utilities operating in a monopolistic market have an obligation to serve
19 their customers reliably at the lowest possible costs. However, unlike entities
20 operating in a competitive environment, Florida's regulated utilities are insulated
21 from a large portion of the normal operating risks faced by unregulated entities.
22 The customer base is not at risk due to poor performance and the recovery of a
23 large percentage of operating costs is essentially guaranteed through cost recovery

1 clauses (subject to prudency review) or through tax adders to customer bills.
2 These clauses significantly reduce the utility's risks of operations by essentially
3 "guaranteeing" the Company recovery of prudently incurred costs. As shown in
4 PEF's December, 2004 Surveillance Report, in 2004, 59.42% of PEF's revenues
5 were received through cost recovery clauses and adders. Cost recovery clauses
6 accounted for 54.96% of PEF's jurisdictional revenue and 4.47% was recovered
7 through direct tax adders to customer bills. The cost recovery clauses and adders
8 covered approximately 67.09% of PEF's total operating expenses. This does not
9 provide incentives for the utility to reduce costs, but does protect against volatility
10 of expenses, thereby reducing risks of losses to shareholders.
11 PEF's remaining expenses are included on a dollar-for-dollar basis in the
12 development of base rates using a proforma Test Year. Once those rates are
13 established, PEF's profitability is dependent upon the actual costs incurred (which
14 is controllable by PEF) and the level of revenues received (which is not
15 controllable by PEF). This portion of the ratemaking process thus gives the utility
16 two incentives: the first is to overestimate expenses and underestimate sales and
17 revenues when seeking a change in base rates, and the second is to reduce
18 expenses between rate proceedings in order to maximize profits.
19 Under current regulatory ratemaking, the last component of a utility's rate
20 structure is the return on rate base. In exchange for the obligation to serve, the
21 regulated utilities are provided with an opportunity to earn a fair return on their
22 investments in assets used to serve customers. Since rates are set to include a fair
23 return on the utility's investment in assets used to serve customers, the incentive

1 is to maximize investment and to persuade the regulatory authority to set its "fair
2 return" as high as possible.
3 After the rates are set, the utility will attempt to maximize its profits by reducing
4 its costs. Although it cannot control sales, the utility will also reap the benefit of
5 higher sales if its rates are set based on an unrealistically low sales estimate.
6 Q: HOW WOULD A RATE OF RETURN ADDER CHANGE THE COMPANY'S
7 INCENTIVES?
8 A: A rate of return adder will not change the utility's incentives. Since actual returns
9 are not based on the rate of return set in a rate proceeding, an "incentive" rate of
10 return adder would not change the Company's incentives. Once rates are set, the
11 Company will still have the incentive to maximize returns by reducing expenses
12 between rate cases. A rate of return adder will not really provide an incentive to
13 promote future performance. Such an adder would simply be an additional
14 reward.
15 Q: DOES A UTILITY NEED A RATE OF RETURN ADDER TO ENCOURAGE
16 INVESTORS TO INVEST CAPITAL IN THE COMPANY?
17 A: No. The discounted cash flow and risk premium methodologies employed by the
18 cost of capital witnesses already reflect the relative risk of the Company and the
19 markets in which it is operating. The Company's proposal for a rate of return
20 adder provides additional "upside" for the Company, while still providing the
21 protections inherent in regulation. This adder is not a reasonable cost of
22 providing service, is not necessary to attract capital, and does not provide any

1 additional incentives for improved performance. PEF's proposed adder would be
2 a windfall to shareholders at customer expense.
3 Q: ARE RATEPAYERS PAYING FOR OTHER PERFORMANCE INCENTIVES?
4 A: Yes. As shown on Schedule C-35, PEF has estimated that it will incur $19.4
5 million in Test Year incentive compensation. In 2004, the incentive
6 compensation was $26.6 million. Even with this level of performance-based
7 compensation, the Company still earned a 13.48% rate of return on equity on an
8 FPSC adjusted basis.
9 Q: SHOULD THE COMMISSION APPROVE PEF'S PROPOSED ROE ADDER
10 OR SOME OTHER ADDER AT A LOWER LEVEL?
11 A: No. The Commission should not approve any adder to the "fair" ROE. As
12 demonstrated above, any rate of return adder is not a legitimate or reasonable cost
13 of providing service and is not an appropriate or meaningful incentive for future
14 performance.
15 Q: DR. CICCHETTI DISCUSSED PERFORMANCE BASED AND INCENTIVE
16 PLANS IN OTHER NON-RESTRUCTURING JURISDICTIONS. DO YOU
17 HAVE ANY CONCERNS REGARDING DR. CICCHETTI'S CONCLUSIONS?
18 A: Yes. On page 44 of his testimony, Dr. Cicchetti described a sharing plan
19 employed by the Georgia Public Service Commission. As explained by Dr.
20 Cicchetti, Georgia Power Company has a sharing plan that authorizes it to earn an
21 ROE within a specified band. This band ranges from 10.25% to 12.25%. If
22 Georgia Power earns above the ROE band range, it shares the excess earnings
23 with its customers. In response to FRF's Interrogatory No. 25, the Company also

1 provided a description of the performance incentive plans for the other companies
2 listed in Table 10 of Dr. Cicchetti's testimony. As shown in that response, each
3 of these companies is subject to some form of sharing when profits are above a
4 predetermined range. Even though Dr. Cicchetti's proposed ROE adder does not
5 include a sharing provision, he concludes that:

6 While PEF is not suggesting a performance based sharing
7 mechanism be implemented at this time, the 50 basis point
8 adder for PEF's superior performance accomplishes the
9 same incentives, and as I described above, would be a good
10 approach for PEF. (Dr. Cicchetti Direct Testimony, page
11 45)

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

1 Q: WHAT IS THE IMPACT OF ELIMINATING PEF'S REQUESTED 50 BASIS
2 POINT ROE ADDER TO ITS REQUESTED RETURN ON EQUITY?
3 A: Eliminating the 50 basis point adder reduces PEF's requested rate of return from
4 9.49% (adjusted for the non-utility equity error) to 9.21%. This adjustment
5 reduces the Test Year revenue requirement by $21.9 million, as shown on
6 Exhibit__(SLB-4), page 1 of 3.
7 Q: PLEASE DESCRIBE THE 90 BASIS POINT ROE ADJUSTMENT MADE BY
8 DR. VANDER WEIDE.
9 A: Dr. Vander Weide selected two proxy groups on which he calculated the average
10 return on equity, using five different cost of equity models. He determined that
11 the average cost of equity for these two groups is 11.4%. However, he then added
12 90 basis points to his recommended ROE for PEF based on his claim that PEF's
13 capital structure was more risky than the average capital structure of the proxy
14 groups. He determined the level of adjustment by determining the weighted
15 average cost of capital of the proxy groups, then "backing into" the ROE that
16 would be required for PEF to earn the weighted average cost of capital, given its
17 supposedly higher debt ratio.
18 Q: WHY IS DR. VANDER WEIDE'S PROPOSED 90 BASIS-POINT ROE
19 ADJUSTMENT INAPPROPRIATE?
20 A: Dr. Vander Weide's 90 basis-point adjustment to ROE is inappropriate for two
21 reasons. First, capital structure is not the only risk that rating agencies or investors
22 take into account when determining a company's risk relative to other potential
23 investments. In fact, Dr. Vander Weide lists a myriad of risk factors considered

1 by the investment community. Investment analysts assign measures of risk to
2 companies, such as S&P's "business risk profile" ranking and ValueLine's safety
3 rating. Dr. Vander Weide's ROE analyses have already taken these risk measures
4 into account.
5 Second, Dr. Vander Weide based his adjustment on PEF's target capital structure,
6 which incorporates 55% equity *after* including an adjustment to the debt
7 component for PEF's purchased power contracts. Dr. Vander Weide did not,
8 however, make similar adjustments to his proxy groups, thereby overstating their
9 equity components relative to PEF's.

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

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

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

15 He then goes on to describe the primary factors that affect the business and
16 financial risks of companies such as PEF. Those factors included demand
17 uncertainty, operating expense uncertainty, investment uncertainty, high operating
18 leverage, high degree of financial leverage, and regulatory uncertainty.
19 On pages 36 and 37 of his testimony, Dr. Vander Weide claims that his electric
20 company proxy group is comparable in risk to PEF. He notes that the average
21 Value Line Safety Rank for the proxy group was 2 and that the Value Line Safety
22 Rank for PEF's parent company is also 2. He also claims that the average S&P
23 bond rating of his chosen proxy group is "approximately BBB+" with an average

1 business risk profile of 5.7 and that the S&P bond rating for PEF's parent
2 company is BBB with a business risk profile of 6. While PEF's parent company
3 may have a business risk profile of 6, PEF's other witness, Mr. Sullivan, noted, on
4 page 8 of his testimony, that S&P considers PEF to have a business risk profile of
5 5.

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

8 A: No.

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

13 A: Dr. Vander Weide noted several operating expense uncertainties, including:
14 (a) the prospect of rising employee health care and pension expenses;
15 (b) variability in storm-related expenses due to severe weather;
16 (c) the prospect of increased expenses for security related to the threat of
17 terrorist activities;
18 (d) high volatility in fuel prices; and
19 (e) uncertainty in the cost of purchased power.

20 The Commission, however, should readily recognize that PEF is quite effectively
21 insulated from all but one of these uncertainties. In fact, the price uncertainties
22 associated with storm-related expenses, incremental security costs, fuel costs, and
23 purchased power are all greatly mitigated, by the use of adjustment clauses and

1 surcharges. As explained above, more than 67% of PEF's total operating
2 expenses are covered through pass-through clauses and tax adders. While PEF
3 does bear the risk of uncertainties in health costs and pension expenses, this is a
4 common price risk that is spread among all companies in all industries.
5 PEF's recovery of costs through adjustment clauses and the recent decision in the
6 storm damage case, along with the recent enactment of the Securitization Bill into
7 Florida law, should also mitigate concerns over regulatory risks. Further, the lack
8 of movement towards retail competition in Florida provides additional assurances
9 for investors.
10 PEF recognizes the reduction in risks associated with the Commission's treatment
11 of its purchased power expenses. In fact, in a letter to S&P on April 12, 2005,
12 PEF's witness, Mr. Sullivan, claimed that:

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

1 bondholders from any incremental financial risk associated with
2 these contracts. (FRF Request for Production of Documents No.
3 28)

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

9 A: Dr. Vander Weide calculated an average capital structure for the electric proxy
10 group as having 40.7% debt, 1.34% preferred stock, and 57.97% common equity.
11 Based on this capital structure, the weighted cost of capital would be 8.433%. He
12 then calculated the average capital structure for the gas proxy group as having
13 33.90% debt, .24% common stock, and 65.86% common equity. Based on this
14 capital structure, the weighted cost of capital for the gas group would be 8.962%.
15 He then averaged the weighted cost of capital for the two proxy groups, which
16 was 8.697%. When he applied this overall cost of capital to PEF's target
17 structure, the after-tax cost of common equity was 12.35%.

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

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

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

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

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

12 A: No. It should be noted that this is the capital structure PEF claims would be
13 applicable before any adjustment for the off-balance sheet obligations; however,
14 PEF made several adjustments to its capital structure to offset the off-balance
15 sheet obligation adjustment that it anticipates will be made by the rating agencies.
16 Unless Dr. Vander Weide makes off-balance sheet adjustments to the capital
17 structures of his chosen proxy group, his adjustment should reflect the capital
18 structure achieved after applying the Company's proposed adjustments to equity.
19 In other words, the capital structure comparison made by Dr. Vander Weide was
20 comparing "apples to oranges." As explained earlier in my testimony, PEF has
21 made an adjustment to increase equity so that, when rating agencies apply the off-
22 balance obligation adjustment, PEF will be at its targeted capital structure. As
23 shown on Exhibit__(SLB-4), page 2 of 3, PEF's capital structure after all of its

1 recommended adjustments provides 63.00% common equity, .59% preferred
2 stock, 35.82% long-term debt, and .59% short-term debt. This is the capital
3 structure that should be compared to the proxy group capital structures in order to
4 compare "apples to apples" in making the adjustment proposed by Dr. Vander
5 Weide. If Dr. Vander Weide's methodology were applied to this capital structure,
6 the resulting ROE would be 10.87% as shown in the table below.

7
8
9

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%

10
11 Q: WHAT WOULD BE THE REVENUE IMPACT OF REDUCING PEF'S ROE
12 TO 10.87%?
13 A: As shown on Exhibit__(SLB-4), page 3 of 3, if Dr. Vander Weide had utilized the
14 Company's proposed capital structure in making his risk adjustment, the resulting
15 ROE would have been 10.87%. The revenue impact of decreasing the return on
16 equity from the Company's recommended ROE of 12.8% is $61.2 million, or
17 29.86% of PEF's requested increase in base rates (as adjusted for the non-utility
18 equity error). This includes the impact of removing the 50 basis point adder,
19 which is $21.9 million; therefore, the individual impact of reducing the ROE from
20 Dr. Vander Weide's recommended 12.3% rate to the recalculated 10.87% rate is
21 $39.3 million, or 19.2% of the Company's adjusted rate increase.

1 Q: PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE
2 COMMISSION.
3 A: PEF has made several adjustments to its capital structure and cost of equity which
4 are unnecessary, do not provide proper incentives, and reflect improper risk
5 adjustments. The Commission should reject PEF's proposals to (i) continue the
6 CR3 adjustment to the capital structure (ii) increase the ROE by 50 basis points
7 as a performance reward, and (iii) increase the ROE by 90 basis points to reflect
8 PEF's risk relative to the proxy group. These adjustments should not be reflected
9 in the Commission's final determination of the cost of capital for PEF, based upon
10 its evaluation of the fair rate of return on equity. In addition, the non-utility
11 equity adjustment error should be corrected.
12 Q: SHOULD THE COMMISSION CONSTRUE YOUR TESTIMONY AS
13 SUPPORTING OR AGREEING THAT AN ROE OF 10.87% IS
14 REASONABLE?
15 A: No. My recommendations only extend to eliminating PEF's requested 50 basis
16 point "incentive" reward and its 90 basis-point "riskiness" factor. There are many
17 other factors that go into determining a fair rate of return on equity, and many
18 other analyses that are performed in such determinations, which have been
19 addressed by other witnesses in this case.

1 DISTRIBUTION RELIABILITY INITIATIVES

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

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

18 Q: WHAT WAS THE LEVEL OF PEF'S OVERSTATEMENT OF
19 DISTRIBUTION RELIABILITY INITIATIVE COSTS IN DOCKET NO.
20 000824-EI?

21 A: In PEF's response to OPC's Interrogatory No. 49, PEF provided a breakdown of
22 the actual expenditures for its distribution initiatives. A comparison of PEF's

1 claimed distribution reliability initiative costs in Docket No. 000824-EI to its

2 actual expenses incurred is shown in the following table.

3

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%

4

5 Q: DID PEF COMPLETE THE PROGRAMS THAT IT INCLUDED IN ITS

6 REQUESTED REVENUE REQUIREMENT IN DOCKET NO. 000824-EI?

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

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

9 that:

10 The Company has made a commitment to the Commission and its

11 customers to improve customer satisfaction and system reliability as part

12 of its Commitment to Excellence. In order to fulfill this commitment, the

13 Company was on track to perform a number of activities that got

14 interrupted by the hurricanes. (Portuondo Rebuttal, Docket No. 041272-

15 EI, page 31.)

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

17 PEF's Commitment to Excellence (CTE) program identified in 2001

18 investments in the transmission and distribution systems . . . . The

19 Company started work on improving reliability immediately in 2001 and

20 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.

1 August. (Wimberly Rebuttal, Docket No. 041272-EI, Page 6) (Emphasis
2 in original).
3 In this case, PEF's witness, Mr. McDonald also indicates that the program was
4 completed.
5 . . .This was accomplished through the successful completion of our
6 Commitment to Excellence (CTE) program as well as other, additional
7 initiatives. (McDonald Direct Testimony, Page 3)
8 Mr. Oliver also contends that the program was completed:
9 We successfully completed our Commitment to Excellence program,
10 making significant improvements in several areas of our operations for
11 employees and customers. (Oliver Direct Testimony, page 3)
12 A review of the Docket No. 000824-EI projections for the distribution reliability
13 initiatives compared to actual expenditures over the 2002 through 2004 period
14 shows that a number of expected projects were either not completed or cost
15 substantially less than PEF had represented. For example, the Company projected
16 $1.5 million for the Transformer Replacement and Inspection Program, yet only
17 spent $100,000. The Company also projected $6.432 million in Targeted Feeder
18 Analysis, yet only spent $2.9 million in total for "other initiatives", including the
19 Targeted Feeder Analysis (as well as infrared inspection, small diameter OH wire,
20 system contingency improvements, AMR, data mapping Suncoast network,
21 switch maintenance, RUDI, project management, visual inspection program
22 overhead mechanical switches, and prior year programs, per PEF's response to
23 OPC's Interrogatory No. 49).

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

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

7 A: As explained earlier, under standard regulatory ratemaking practices, the utility
8 has the incentive to overestimate expenses when setting rates, and then to cut back
9 on expenses to increase returns after the rates are in place. While I cannot
10 definitively say *why* PEF overestimated its distribution expenses in Docket No.
11 000824-EI, the result is the same. Exhibit__(SLB-5) summarizes projected versus
12 actual distribution spending from 2002 to 2004 and projected versus actual
13 distribution initiative spending over that same period. Although PEF projected
14 $6.948 million in annual operating and maintenance expenses for distribution
15 reliability initiatives in Docket No. 000824-EI, it actually spent an average of only
16 $3.1 million a year from 2002 through 2004. The overstatement of costs is even
17 greater when PEF's total distribution operating and maintenance expense
18 projection in Docket No. 000824-EI is compared to its actual expenditures for the
19 same period. PEF projected annual distribution O&M expenses of $97.1 million,
20 or $291.3 million over the 3 year period. Actual expenditures were only $259.9
21 million, indicating an overstatement of $31.44 million, or 12.1%, over the three-
22 year period. This overstatement had the impact of increasing PEF's return on

1 equity. In 2004, the overstatement increased PEF's after-tax return on equity by
2 0.3741% (37 basis points).

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

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

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

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

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

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

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

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

1

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

2

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

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

16 In addition to the large requested increase in incremental vegetation management
17 costs, it appears that costs may have been deferred into the Test Year. For
18 example, as noted previously, transformer replacements and inspections were

1 projected to cost $1.5 million in Docket No. 000824-EI, yet PEF only spent
2 $100,000 on this program. Now, in the current Test Year, PEF is requesting an
3 additional $2.3 million for transformer inspections, repairs, and replacements.
4 This is a clear example of the ratemaking incentives I described earlier in my
5 testimony. When setting rates, PEF overstated its expenses, then, in the
6 intervening years, PEF spent less than it had included in setting its base rates,
7 resulting in higher profits.

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

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

18 TRANSMISSION RELIABILITY INITIATIVES

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

21 A: Yes. As with the distribution reliability initiatives, PEF's estimates of
22 transmission expenses were significantly overstated in Docket No. 000824-EI.
23 Exhibit__(SLB-6) summarizes PEF's projected versus actual transmission

1 spending from 2002 to 2004 and project versus actual transmission initiative
2 spending over that same period. Over the three-year period from 2002 through
3 2004, PEF estimated total operating and maintenance expenses of $34.3 million a
4 year, or $102.9 million, with reliability initiatives accounting for $9.73 million a
5 year, or $29.19 million of the total. Actual transmission operating and
6 maintenance expenses over the same time period were only $85.874 million,
7 indicating an overstatement of $17.026 million or 19.8%. Actual expenditures for
8 transmission reliability initiatives were only $22.8 million; therefore, PEF
9 overstated the operating and maintenance expense portion of the transmission
10 reliability initiatives by $6.39 million, or 28%.

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

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

17 Q: DID PEF BENEFIT FROM ITS LOWER SPENDING LEVELS?

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

1 basis points) in 2004 by keeping transmission and distribution costs lower than
2 anticipated in its last rate filing.
3 Q: IS THE COMPANY ASKING FOR FURTHER RELIABILITY INITIATIVES
4 TO BE INCLUDED IN THE TEST YEAR REVENUE REQUIREMENT?
5 A: Yes. As explained by PEF Witness, Mr. Desouza, PEF is requesting an additional
6 $10 million in "accelerated & proactive reliability initiatives." (Desouza Direct
7 Testimony, Pages 11-12)
8 Q: SHOULD THE COMMISSION ADJUST PEF'S REQUESTED TEST YEAR
9 TRANSMISSION EXPENSES?
10 A: Yes. PEF's transmission reliability initiative costs for the Test Year should be
11 limited to the percentage of actual expenses incurred from 2002 through 2004 as
12 compared to estimated expenses in Docket No. 000824-EI. This adjustment
13 would reduce the Test year transmission operating and maintenance expenses by
14 $2.189 million. The jurisdictional revenue impact of this adjustment is $1.564
15 million.
16 <u>GAINS ON SALES OF UTILITY PROPERTY</u>
17 Q: WHAT IS THE COMMISSION'S POLICY REGARDING GAINS ON SALES
18 OF UTILITY PROPERTY?
19 A: The Commission's policy has been to amortize any gains from sales of utility
20 property as offsets to revenue requirements over a five-year period.
21 Q: HAS PEF HAD ANY GAINS ON SALES OF UTILITY PROPERTY THAT
22 SHOULD BE AMORTIZED AS AN OFFSET TO THE TEST YEAR
23 REVENUE REQUIREMENT?

1 A: Yes. PEF recently closed on its sale of the distribution system in Winter Park to
2 the City of Winter Park, which has established a municipal electric utility system.
3 Q: DID PEF INCLUDE ANY GAINS AS AN OFFSET TO THE TEST YEAR
4 REVENUE REQUIREMENT?
5 A: No.
6 Q: WHAT WAS PEF'S CLAIMED REASON FOR FAILING TO AMORTIZE
7 THE WINTER PARK GAIN?
8 A: As PEF explained in its response to FRF Interrogatory No. 43:
9 The impact from the sale of utility assets to Winter Park was not included
10 in the filing because the date on which the purchase would be
11 consummated and operational control would be transferred had not been
12 established at the time of filing, and that date still has not been established
13 with certainty at the time of providing this answer.
14 Q: IS THIS A VALID REASON FOR PEF TO EXCLUDE THE GAIN FROM THE
15 WINTER PARK SALE IN CALCULATING ITS REVENUE REQUIREMENTS
16 IN THIS CASE?
17 A: No. Although PEF claimed the date had still not been established with certainty
18 at the time of providing the answer, the Winter Park sale closed on June 1,
19 2005—26 days before PEF's response to FRF Interrogatory No. 43 was filed.
20 Additionally, on May 31, the Commission approved Winter Park's new electric
21 tariffs. In its order approving those tariffs, issued on June 13, 2005, the
22 Commission noted that the City of Winter Park had purchased PEF's distribution

1 system in the City. Further, PEF's failure to amortize the gain in the Test Year is
2 not excused by its lack of certainty of the purchase date.
3 Q: SHOULD PEF BE REQUIRED TO ESTIMATE THE GAIN AND AMORTIZE
4 IT AS AN OFFSET TO THE TEST YEAR REVENUE REQUIREMENTS?
5 A: Yes.
6 Q: HAS PEF PROVIDED A CALCULATION OF THE GAIN?
7 A: No. In its response to FRF's Interrogatory No. 21, PEF indicated that the gain or
8 loss resulting from the sale has not yet been quantified.
9 Q: WHAT IS THE MAGNITUDE OF THE GAIN EXPECTED FROM THE SALE?
10 A: The arbitration award indicated that the value of PEF's distribution assets was
11 approximately $9 million on a Replacement Cost Less Depreciation valuation.
12 This would be greater than PEF's original cost less depreciation on which a gain
13 would be calculated. This amount was later adjusted to $8.2 million. The total
14 purchase price, as set forth in the Transfer Agreement, was $41,718,447, broken
15 down as follows:

Line	Item	Amount
16	Equipment and fixtures	$ 8,218,447
17	Stranded costs	$ 7,689,000
18	CWIP true-up	$ 2,800,000
19	Half Joint-Use Attachment Inventory	$ 15,000
20	Real Estate and Easements	$10,000,000
21	Going Concern Value	$12,000,000
22	Separation and Reintegration	$ 996,000
23	Total	$41,718,447

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

1 resulting impact to Test Year revenue requirements would be 1/5 of the gain, or
2 $5.96 million.

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

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

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

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

1 Q: HOW COULD THE COMMISSION PROTECT THE REMAINING RETAIL
2 RATEPAYERS?
3 A: While it is inappropriate for the remaining retail ratepayers to pay for Winter
4 Park's share of the storm damage costs, the amount can be effectively viewed as a
5 reduction to the gain on the sale. In other words, the gain could be viewed as
6 partially repaying the hurricane damage costs, with the remainder attributable to
7 actual gain on the sale. The net amount to be credited to ratepayers would be the
8 same under either circumstance. However, the Commission could protect the
9 remaining retail ratepayers by adjusting its policy, in this instance, to allow the
10 ratepayers to receive the gain over an accelerated basis, beginning January 1,
11 2006 and continuing for a two-year period. This accelerated amortization would
12 partially offset the added burden that ratepayers are bearing through the
13 implementation of the SCRC. Based on my preliminary calculations of the gain,
14 this adjustment would reduce the Test Year revenue requirements by $14.9
15 million.
16 CONSTRUCTION WORK IN PROGRESS
17 Q: HAS THE COMPANY INCLUDED CONSTRUCTION WORK IN PROGRESS
18 ("CWIP") IN RATE BASE?
19 A: Yes. As shown on Schedule B-1, the Company has included $82.105 million of
20 CWIP in rate base.
21 Q: SHOULD CWIP BE INCLUDED IN RATE BASE?
22 A: No. In past decisions, the Commission has evaluated the need for including
23 CWIP in rate base by determining the amount needed for the Company to

1 maintain financial integrity. The main factor used to measure financial integrity
2 has been interest coverage. On page 20 of his testimony, Dr. Vander Weide set
3 forth the S&P financial guidelines for an A-rating. As shown on Table 2 of his
4 testimony, the interest coverage ratio guidelines for an A-rating are between 3.8 x
5 and 4.5 x. This means that, to achieve an A-rating, a utility should have earnings
6 before income taxes between 3.8 and 4.5 times its interest expense. As shown on
7 Schedule D-9, PEF has indicated Test Year interest coverage ratios (excluding
8 AFUDC) of 5.04 times at present rates and 6.77 times at proposed rates. As
9 shown on Exhibit__(SLB-7), removing CWIP from rate base, and reducing
10 revenues and net income accordingly, reduces the Test Year interest coverage
11 ratio at proposed rates from 6.77 to 6.67 times, yielding a reduction of 0.1 times.
12 The Test Year interest coverage ratio at present rates drops from 5.04 times to
13 4.94 times, which is still comfortably above the high end of the range needed for
14 an A-rating. Since PEF's EBIT interest coverage is greater than the level needed
15 for an A rating, even without CWIP in rate base, PEF's CWIP should be removed
16 from rate base.

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

19 A: The revenue impact of removing CWIP from rate base is $12.721 million.
20 ($82.105 million x 9.4939% x 1.6320).

1 BAD DEBT EXPENSE

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

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

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

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

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

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

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

19 A: No.

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

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

1 Q: WHAT IS THE REVENUE IMPACT OF REDUCING THE TEST YEAR BAD
2 DEBT FACTOR FROM 0.1743% TO 0.1444%?
3 A: The use of this factor reduces the Test Year write-offs from $6.298 million to
4 $5.194 million. In addition, reducing the bad debt factor also reduces the revenue
5 expansion factor from 1.63202 to 1.63153. The combined impact of these
6 adjustments is a reduction in the Test Year revenue requirement of $1.162
7 million. These calculations are shown on Exhibit__(SLB-8).
8 WORKING CAPITAL
9 Q: DO YOU HAVE ANY CONCERNS WITH THE AMOUNT OF WORKING
10 CAPITAL PEF HAS INCLUDED IN RATE BASE?
11 A: Yes. I have several concerns with the amount of Working Capital that PEF has
12 included in rate base. PEF has understated its regulatory liabilities associated
13 with Last Core Nuclear Fuel and End-of-Life ("EOL") Nuclear Materials and
14 Supplies Inventory. These understatements have the direct effect of overstating
15 Working Capital and thus overstating rate base. The Working Capital component
16 of rate base has also been overstated by an improper jurisdictional allocation in
17 the removal of the storm damage reserve that is to be recovered through the Storm
18 Cost Recovery Clause ("SCRC"). In addition, PEF has included the unamortized
19 balance of Rate Case expenses in rate base. The net effect of these Working
20 Capital errors is an increase to the jurisdictional rate base of $21.929 million,
21 resulting in an overstatement of the jurisdictional Test Year revenue requirement
22 of $3.4 million. The Commission should, accordingly, disallow these amounts
23 from rate base and revenue requirements, respectively.

1 Q: HOW HAS PEF UNDERSTATED ITS REGULATORY LIABILITIES
2 ASSOCIATED WITH LAST CORE NUCLEAR FUEL AND END OF LIFE
3 NUCLEAR MATERIALS AND SUPPLIES INVENTORY?
4 A: PEF has proposed reduced accruals to its Last Core Nuclear Fuel and EOL
5 Materials and Supplies reserves. While these accruals would reduce the reserve
6 balances for the end of the Test Year, PEF has incorrectly assumed a beginning
7 reserve balance for the Test Year that is significantly less than the actual reserve
8 balances. In accordance with Order No. PSC-02-0055-PAA-EI in Docket Nos.
9 981246-EI, 001835-EI, 990342-EI, and 991931-EI, PEF has been accruing $1.1
10 million a year into the Last Core Nuclear Fuel reserve and $1.5 million a year into
11 the End of Life Materials and Supplies Inventory reserve. As shown on Schedule
12 B-21, Page 6 of 6, the balances in the Last Core Nuclear Fuel and EOL Materials
13 and Supplies reserves at December 31, 2004 were $4.4 million and $6 million,
14 respectively. With the accruals continued through 2005, the balances at
15 December 31, 2005 will be $5.5 million and $7.5 million; however, as shown on
16 Schedule B-21, Page 3 of 6, the amounts PEF included in the calculation of the
17 reserve balances at December 31, 2005 were only $1.459 million and $4.217
18 million for the Last Core and EOL reserves, respectively.
19 Q: DID PEF REVISE SCHEDULE B-21?
20 A: Yes. PEF revised its Schedule B-21 in response to FRF Interrogatory No. 55;
21 however, the revised Schedule B-21 is still in error. As shown on Revised
22 Schedule B-21, the beginning balance in the Last Core Nuclear Fuel reserve was
23 revised from $1.459 million to $4.217 million. This is still $1.3 million less than

1 the projected December 31, 2005 reserve balance based on continued accruals of
2 \$1.1 million prior to the implementation of revised base rates. In addition, the
3 \$4.217 million is a reduction in the Last Core Nuclear Fuel reserve account from
4 the December 31, 2004 balance, thus implying actual charges against the account,
5 which should not occur until the time the nuclear unit is retired.

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

8 A: The beginning balance of the EOL reserve for the Test Year was revised from
9 \$4.217 million to \$5.750 million. Even with this adjustment, the EOL reserve is
10 \$1.75 million less than it should be at December 31, 2005 and is even \$250,000
11 less than it actually was at December 31, 2004. Again, this implies no accruals
12 for 2005 and, in fact, results in charges against the account. The purpose of the
13 EOL reserve is to pay for materials and supplies on hand at the nuclear facility at
14 the time of retirement. There is no reason for charges against the reserve until
15 that time.

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

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

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

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

1 Materials and Supplies reserve. These accruals were then offset by charges
2 against the reserves, resulting in no change to the reserve for the Test Year.
3 Q: WHAT WERE THE ACCRUALS FOR THE TEST YEAR?
4 A: PEF has included accruals of $764,000 and $681,000 for the Last Core Nuclear
5 Maintenance and EOL Materials and Supplies reserves, respectively. These
6 amounts should be added to the reserves in the Test Year, thus increasing the
7 regulatory liability and reducing rate base.
8 Q: DID PEF MODIFY ITS REVENUE REQUIREMENT BASED ON ITS
9 REVISED SCHEDULE B-21?
10 A: No. In its response to FRF's Interrogatory No. 55, PEF claimed that the net effect
11 of the change does not impact the total rate base as reflected on Schedule B-1.
12 Q: DO YOU AGREE WITH PEF'S CONCLUSION THAT THE CHANGE DOES
13 NOT IMPACT RATE BASE?
14 A: No. A review of PEF's Working Capital schedules shows that the Working
15 Capital component includes the balances in Accounts 228.1 through 228.4.
16 Therefore, any understatement of the regulatory liability has been carried forward
17 into rate base.
18 Q: HAS PEF PROVIDED ANY ADDITIONAL INFORMATION ON THE LAST
19 CORE NUCLEAR FUEL AND EOL MATERIALS AND SUPPLIES
20 BALANCES?
21 A: Yes. In response to OPC's Interrogatory No. 3, PEF provided a detailed trial
22 balance showing expected balances as of December 31, 2005. As shown in that
23 response, PEF assumed end-of-year balances of $4,675,009 and $6,375,000 for

1 the Last Core Nuclear Fuel and EOL Materials and Supplies, respectively. These
2 balances assume 2005 accruals of only $275,000 for Last Core Nuclear Fuel and
3 $375,000 for EOL Materials and Supplies, which are significantly less than the
4 amounts actually accrued in accordance with Order No. PSC-02-0055-PAA-EI.

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

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

10

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

11
12
13 Q: WHAT IS THE IMPACT OF ADJUSTING THE LAST CORE AND EOL
14 MATERIALS AND SUPPLIES RESERVE BALANCES ON PEF'S TEST
15 YEAR REVENUE REQUIREMENT?

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

1 Q: HOW DID THE COMPANY ERR IN REMOVING THE STORM COST
2 RECOVERY CLAUSE REGULATORY ASSET FROM WORKING CAPITAL?
3 A: As shown on Schedules B-21 and B-17, Page 2 of 3, the Company has removed
4 $139 million from its working capital associated with amounts that will be
5 recovered through the SCRC. While this removal is appropriate since the SCRC
6 includes the addition of interest charges, PEF has incorrectly allocated a portion
7 of this amount to the wholesale jurisdiction, resulting in a credit to Working
8 Capital of only $126.3 million. In its response to FRF Interrogatory No. 59, PEF
9 provided a breakdown of the Test Year Other Regulatory Assets. On that
10 response, PEF indicated that the Regulatory Asset associated with the retail SCRC
11 is $139 million and the Regulatory Asset associated with the wholesale storm
12 damage is $11.9 million. Therefore, the full $139 million should be deducted
13 from the jurisdictional rate base.
14 Q: WHAT IS THE REVENUE IMPACT OF THIS ADJUSTMENT?
15 A: This adjustment would decrease rate base by $12.732 million, resulting in a
16 reduction in the Test Year revenue requirement of $1.973 million.
17 Q: WHAT OTHER ADJUSTMENTS SHOULD BE MADE TO WORKING
18 CAPITAL?
19 A: Based on previous Commission precedent, the unamortized balance of rate case
20 expenses should be excluded from rate base. This adjustment reduces the rate
21 base by $2.25 million, with a corresponding $348,618 reduction in the Test Year
22 revenue requirement.

1 Q: DID ANY OF THESE ADJUSTMENTS AFFECT THE ACCUMULATED
2 DEFERRED INCOME TAXES INCLUDED IN THE CAPITAL STRUCTURE?
3 A: Apparently not. As shown on Schedule C-22, PEF adjusted its deferred income
4 taxes in the Test Year for $2.5 million associated with the Last Core and EOL
5 reserve accruals. While this amount should have been $2.6 million, the
6 adjustment shows that PEF was assuming an increase in the associated Account
7 190 deferred income tax balances. As shown on Schedule D-1b, PEF also
8 adjusted its deferred income taxes to remove the effects of storm costs. Lastly,
9 while PEF made a pro-rata adjustment to the capital structure for the $2.25
10 million average rate base associated with rate case expenses, it did not make a
11 corresponding adjustment to deferred income taxes; therefore, removal of the rate
12 base item would not require removal of an associated deferred income tax.

13 RATE CASE EXPENSES

14 Q: WHAT IS THE TOTAL REVENUE REQUIREMENT INCLUDED IN THE
15 TEST YEAR FOR RATE CASE EXPENSES?
16 A: The Company has included $1.5 million of rate case expenses in the Test Year,
17 along with a regulatory asset of $2.25 million in working capital. The total
18 revenue requirement included in the Test Year associated with rate case expenses
19 is thus $1.849 million as shown on Exhibit__(SLB-9).

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

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

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

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

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

21 The Commission should thus deny PEF's request to defer the rate case expenses
22 for recovery in the Test Year. Elimination of rate case expenses would reduce the
23 Test Year revenue requirement by $1.5 million. The associated rate base

1 component should also be removed and was addressed in the Working Capital
2 portion of my testimony.

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

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

1 Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR RATE CASE
2 EXPENSES.
3 A: In all cases, the unamortized deferred rate case expenses should be removed from
4 rate base. This adjustment is explained in the Working Capital section of my
5 testimony and reduces the Test Year revenue requirement by $348,618.
6 The Commission should deny PEF's request for deferral and recovery of rate case
7 expenses in the Test Year. This adjustment would reduce the Test Year revenue
8 requirement by $1.5 million. If the Commission chooses to allow deferral, the
9 Commission should require PEF to book a regulatory liability if the rates are not
10 changed following the amortization period.
11 STORM DAMAGE ACCRUALS
12 Q: WHAT IS THE LEVEL OF STORM DAMAGE ACCRUAL THAT PEF IS
13 REQUESTING IN THIS CASE?
14 A: The Company is requesting a $50 million annual accrual to the storm damage
15 reserve. This is a $44 million increase over the present annual accrual of $6
16 million.
17 Q: HAS PEF PERFORMED ANY ANALYSES OF THE EXPECTED ANNUAL
18 UNINSURED STORM DAMAGE COSTS?
19 A: Yes. PEF engaged ABS Consulting to perform a storm damage study. In that
20 study, ABS has analyzed the average expected annual uninsured costs based on an
21 analysis of historical and random storms to determine an average expected level
22 of damage. ABS then applied estimates from the 2004 storm restoration costs to
23 determine the costs associated with the average expected level of damage. Based

1 on this analysis, ABS concluded that the expected annual uninsured cost to PEF's
2 system is estimated to be $15.2 million.
3 Q: HAVE YOU REVIEWED PEF'S ACTUAL STORM DAMAGE COSTS?
4 A: Yes. In exhibit (JP-1) of Mr. Portuondo's testimony submitted November 24,
5 2004 for Docket No. 041272-EI, the Company provided the annual charges to the
6 reserve for storm damages. Beginning with 1994 and ending with the 2004
7 season, the Company experienced storm damage in 9 of the 11 years, although
8 some years were negligible in terms of damage. I escalated the costs from each
9 year to 2006 to account for inflation.
10 Based on PEF's actual experience from 1994 through 2003, the annual average
11 uninsured storm damage cost is $2.252 million. This reflects expected costs for
12 smaller, Category 1 and 2 storms.
13 Q: WHAT HAS BEEN PEF'S EXPERIENCE REGARDING THE FREQUENCY
14 OF LARGER, CATEGORY 3 TO 5 STORMS?
15 A: The National Oceanic and Atmospheric Administration reports that there were
16 only seven Category 3 to 5 storms occurring in Northeast and Northwest Florida
17 from 1900 to 2000, or one approximately every 14 years. Progress Energy's
18 website has a breakdown of major storms affecting its service territories. On that
19 website, the only major storms listed for the PEF service territory are those storms
20 that occurred in 2004. Based on this information, I have assumed that PEF will
21 experience a Category 3 through 5 storm approximately every 10 years, as shown
22 on Exhibit__(SLB-10), page 1 of 3.

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

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

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

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

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

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

1 Florida. Therefore, it is not necessary for the storm damage reserve to cover
2 100% of potential storm damage costs.
3 Q: WHAT LEVEL OF STORM DAMAGE ACCRUAL ARE YOU
4 RECOMMENDING IN THIS CASE?
5 A: I am recommending that PEF be allowed to increase its annual storm damage
6 accrual to the expected annual average storm damage of $15.2 million. This level
7 of accrual is 2.3 times the highest annual storm damage incurred from 1994
8 through 2003 and is 6.7 times greater than the average annual storm damage
9 incurred during that same period. Assuming the average annual storm damage of
10 $2.25 million over a ten-year period, this would allow the reserve balance to
11 increase by $12.75 million a year. While no one can predict when PEF's service
12 territory will experience another major storm, this level of accrual, combined with
13 PEF's ability to seek recovery of any storm damages in excess of reserve balances
14 through a SCRC, provides the protection PEF needs. This level of accrual also
15 protects ratepayers, who are already burdened by the SCRC for the extraordinary
16 2004 storm damage costs, on top of PEF's existing rates that have produced and
17 are continuing to produce extraordinary, excessive returns to PEF's shareholders.
18 Q: WHAT IS THE IMPACT OF REDUCING THE STORM DAMAGE ACCRUAL
19 FROM THE $50 MILLION REQUESTED BY THE COMPANY TO THE
20 $15.2 MILLION EXPECTED ANNUAL AVERAGE STORM DAMAGE?
21 A: As shown on Exhibit__(SLB-10), page 2 of 3, this adjustment reduces the
22 jurisdictional Test Year revenue requirement by $31.125 million. This adjustment
23 takes into account the $34.8 million reduction in the annual accrual and the

1 corresponding decrease in Account 228, which has the effect of increasing rate
2 base.
3 Q: DO YOU HAVE ANY OTHER CONCERNS WITH PEF'S STORM DAMAGE
4 RESERVE?
5 A: Yes. PEF has understated its year-end balance in the storm reserve. In addition,
6 PEF has understated the tax impact of its requested increase to the annual accrual.
7 Q: HOW DID PEF UNDERSTATE ITS YEAR-END BALANCE IN THE STORM
8 RESERVE?
9 A: As shown on Schedule B-21, PEF has assumed a beginning balance of $6.515
10 million, with an accrual of $6 million and an ending balance of $12.015 million
11 (prior to PEF's requested $44 million adjustment in annual accrual). This
12 mathematical error understates the year-end balance by $500,000 and the average
13 Test Year reserve balance by $250,000. This error overstates the jurisdictional
14 Test Year revenue requirement by $37,536. These calculations are shown on
15 Exhibit__(SLB-10), page 3 of 3.
16 Q: HOW DID PEF UNDERSTATE THE TAX IMPACTS ASSOCIATED WITH
17 ITS REQUESTED INCREASE IN THE ACCRUAL TO THE STORM
18 RESERVE?
19 A: PEF has assumed a jurisdictional factor of 96.949% for the storm damage accrual.
20 However, as shown on Schedule C-3, page 1, the net of tax storm reserve
21 adjustment is allocated 99.796% to the retail jurisdiction. A review of the
22 increase to the reserve and the associated income taxes shown on Schedule C-2,
23 page 3 shows that the increase to the reserve is allocated on the 96.949% factor;

1 however, the increase in net operating income for the income tax deduction was
2 calculated at 36.77%, rather than PEF's tax rate of 38.575%. This error results in
3 an overstatement of the jurisdictional Test Year revenue requirements of $1.256
4 million, as shown on Exhibit__(SLB-10), page 3 of 3.

5 Q: IS THIS ADJUSTMENT STILL APPLICABLE IF THE COMMISSION
6 ADOPTS YOUR RECOMMENDED ADJUSTMENT TO THE ANNUAL
7 STORM DAMAGE ACCRUAL?

8 A: Yes. The $31.125 million jurisdictional Test Year revenue impact of reducing the
9 annual accrual to $15.2 million was calculated assuming that the taxes were
10 correctly calculated in PEF's filing; therefore, this adjustment would still be
11 required.

12 Q: DOES THIS CONCLUDE YOUR TESTIMONY?

13 A: Yes, it does.

EXHIBITS OF
SHEREE L. BROWN

ON BEHALF OF
THE FLORIDA RETAIL FEDERATION

Progress Energy Florida
Labor and Benefits Adjustment

Line	Description	C-35	Amount Capitalized [1]	Amount Expensed [1]
1	Base Payroll	272,926,655	116,856,385	156,070,270
2	Incentive Compensation Plan	18,761,714	6,670,732	12,090,982
3	Long-Term Incentive Plan	684,000		684,000
4	Total Payroll	292,372,369	123,527,117	168,845,252
5	FICA and Unemployment	23,363,155	8,323,221	15,039,934
6	Workers' Compensation	5,010,000	-	5,010,000
7	Pension Plan Expense	(7,450,000)	-	(7,450,000)
8	OBB Benefit Plans	60,354,789	23,608,337	36,746,452
9	Employee Educational Assistance	658,312	83,000	575,312
10	Performance Awards & Relocation	962,076	297,000	665,076
11	Total Fringe Benefits	82,898,332	32,311,558	50,586,774
12	Total Payroll and Fringe Benefits	375,270,701	155,838,675	219,432,026
13	Cost Recovery Clauses [2]			10,129,832
14	Non-Regulated O&M [3]			4,260,418
15	Amount Expensed in Base Rates			205,041,776
16	Add back Pension Plan Expense			7,450,000
17	Labor and Benefits excl Pension Plan			212,491,776
18	Adjust to Year-End 2004 Employees (C-35)			+4083/4130
19	Adjusted Test Year Payroll and Benefits			210,073,589
20	Adjustment (L.17- L.19)			2,418,187
21	Jurisdictional Allocation (C-20)			0.92421
22	Jurisdictional Adjustment			$ 2,234,913

[1] Response to OPC Interrogatory No. 26.
[2] Amounts allocated to cost recovery clauses per the response to FRF Interrogatory No. 16.
[3] Amounts allocated to Non-Regulated O&M per the response to FRF Interrogatory No. 16.

Progress Energy Florida
Labor and Benefits Adjustment

Line	Base Payroll	C-35	Amount Capitalized [1]	Amount Expensed [1]	Percent Expensed
(a)	(b)	(c)	(d)	(e)	(f)
1	2002	245,246,334	111,648,520	133,597,814	54.47%
2	2003	260,992,358	119,947,187	141,045,171	54.04%
3	2004	292,064,099	152,254,156	139,809,943	47.87%
4	2006	272,926,655	116,856,385	156,070,270	57.18%
5	Revised Expense [1]			148,676,655	54.47%
6	Adjustment			7,393,615	
7	Percent for Clause Recovery and Non-Regulated [2]			3.04%	
8	Test Year Revenue Req [3]			7,169,172	
9	Jurisdictional Factor [4]			92.421%	
10	Jurisdictional Revenue Impact			$ 6,625,821	

[1] Col. c, line 4 x Col. f, line 5, using maximum expense ratio from 2002-2004.
[2] Per the response to OPC Interrogatory No. 16, including non-regulated O&M, ECCR, ECRC and Account 501.
[3] Line 6 x (1-Line 7)
[4] Per Schedule C-20.

Progress Energy Florida
Capital Structure

Capital Structure as Filed by PEF

Line No.	Class	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Ratio for Financial Reporting	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
1	Common Equity	2,715,814	49.68%	874,683	(8,126)	3,582,371	63.11%	0.749341	2,684,417	57.83%	12.80%	7.40%
2	Preferred Stock	33,497	0.61%		(100)	33,397	0.59%	0.749888	25,044	0.54%	4.50%	0.02%
3	Long Term Debt-fixed	2,131,302	38.99%	(97,379)	(6,377)	2,027,546	35.72%	0.749997	1,520,653	32.76%	5.73%	1.86%
4	Short Term Debt	72,288	1.32%	(38,652)	(216)	33,420	0.59%	0.752484	25,148	0.54%	4.04%	0.02%
5	Total for Financial	4,952,901				5,676,734	100.00%					
6	Active Customer Deposits	136,401	2.50%		(408)	135,993		0.749884	101,979	2.20%	5.92%	0.13%
7	ITC-Total	26,572	0.49%	1,587	(80)	28,079		0.749777				
8	Equity								13,485	0.29%	12.70%	0.04%
9	Debt								7,568	0.16%	5.83%	0.01%
10	Deferred Income Taxes	407,236	7.45%	6,596	(1,218)	412,614		0.749853	309,400	6.67%	0.00%	0.00%
11	FAS 109 DIT	(56,547)	-1.03%	(5,098)	169	(61,476)		0.749691	(46,088)	-0.99%	0.00%	0.00%
12	Total	5,466,563	100.00%	741,737	(16,356)	6,191,944			4,641,607	100.00%		9.50%

Adjustment to Correct Error in Eliminating Non-Utility Property

Line No.	Class	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Ratio for Financial Reporting	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
13	Common Equity	2,715,814	49.68%	858,495	(8,126)	3,566,183	63.00%	0.749341	2,672,287	57.72%	12.80%	7.39%
14	Preferred Stock	33,497	0.61%		(100)	33,397	0.59%	0.749888	25,044	0.54%	4.50%	0.02%
15	Long Term Debt-fixed	2,131,302	38.99%	(97,379)	(6,377)	2,027,546	35.82%	0.749997	1,520,653	32.85%	5.73%	1.88%
16	Short Term Debt	72,288	1.32%	(38,652)	(216)	33,420	0.59%	0.752484	25,148	0.54%	4.04%	0.02%
17	Total for Financial	4,952,901				5,660,546	100.00%					
18												
19	Active Customer Deposits	136,401	2.50%		(408)	135,993		0.749884	101,979	2.20%	5.92%	0.13%
20	ITC-Total	26,572	0.49%	1,587	(80)	28,079		0.749777				
21	Equity								13,485	0.29%	12.70%	0.04%
22	Debt								7,568	0.16%	5.83%	0.01%
23	Deferred Income Taxes	407,236	7.45%	6,596	(1,218)	412,614		0.749853	309,400	6.68%	0.00%	0.00%
24	FAS 109 DIT	(56,547)	-1.03%	(5,098)	169	(61,476)		0.749691	(46,088)	-1.00%	0.00%	0.00%
25	Total	5,466,563	100.00%	725,549	(16,356)	6,175,756			4,629,476	100.00%		9.49%

Line No.	Item	Amount
26	Rate Base	$ 4,640,452
27	Revised Rate of Return	9.49%
28	Return on Rate Base	$ 440,562
29	Less Current Return per A-1	314,983
30	Return Deficiency per A-1	$ 125,579
31	NOI Multiplier	1.632
32	Adjusted Revenue Increase	204,945
33	Less Requested Increase	205,556
34	Revenue Impact of Correcting Non-Utility Property Elim.	$ (611)

Note: This correction is made in accordance with PEF's response to White Springs' Interrogatory No. 9.

Progress Energy Florida
Capital Structure

Eliminate CR3 Adjustments

Line No.	Class	Co Total per Books	Ratio	Specific Adjustments w/o CR3	Pro Rata Adjustments	System Adjusted with Off-BS Obligations	Ratio	System Adjusted for FPSC Jurisdiction	Jurisdictional Allocation	Jurisdictional Capital	Ratio for Rates	Cost Rate	Weighted Cost Rate
1	Common Equity	2,715,814	47.56%	748,906	(8,126)	3,456,594	53.86%	3,456,594	74.93%	2,590,168	55.95%	12.80%	7.16%
2	Preferred Stock	33,497	0.59%		(100)	33,397	0.52%	33,397	74.99%	25,044	0.54%	4.50%	0.02%
3	Long Term Debt-fixed	2,131,302	37.33%	12,210	(6,377)	2,137,135	33.30%	2,137,135	75.00%	1,602,845	34.62%	5.73%	1.98%
4	Off-Balance Sheet Adj	757,000	13.26%			757,000	11.80%						
5	Short Term Debt	72,288	1.27%	(38,652)	(216)	33,420	0.52%	33,420	75.25%	25,148	0.54%	4.04%	0.02%
6	Total "Financial"	5,709,901	100.00%			6,417,546	100.00%						
7	Active Customer Deposits	136,401			(408)	135,993		135,993	74.99%	101,979	2.20%	5.92%	0.13%
8	ITC-Total	26,572		1,587	(80)	28,079							
9	Equity							17,985	74.98%	13,485	0.29%	12.70%	0.04%
10	Debt							10,094	74.98%	7,568	0.16%	5.83%	0.01%
11	Deferred Income Taxes	407,236		6,596	(1,218)	412,614		412,614	74.99%	309,400	6.68%	0.00%	0.00%
12	FAS 109 DIT	(56,547)		(5,098)	169	(61,476)		(61,476)	74.97%	(46,088)	-1.00%	0.00%	0.00%
13	Total	11,933,464		725,549	(16,356)	6,932,756		6,175,756		4,629,548	100.00%		9.37%

Line	Item	Amount
14	Rate Base	$ 4,640,452
15	Revised Rate of Return	9.37%
16	Return on Rate Base	$ 434,740
17	Less Current Return per A-1	314,983
18	Return Deficiency per A-1	$ 119,757
19	NOI Multiplier	1.632
20	Adjusted Revenue Increase	195,443
21	Less Requested Increase [1]	204,945
22	Revenue Impact of Eliminating the CR3 adjustment	$ (9,502)

[1] Change is made from corrected weighted average cost of capital of 9.49% as shown on Exhibit__(SLB-3), Page 1 of 3.

Progress Energy Florida
Capital Structure

Remove CR3 Debt Adjustment

Line No.	Class	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Ratio for Financial Reporting	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
1	Common Equity	2,715,814	49.68%	858,495	(8,126)	3,566,183	61.80%	0.749341	2,672,287	56.72%	12.80%	7.26%
2	Preferred Stock	33,497	0.61%		(100)	33,397	0.58%	0.749888	25,044	0.53%	4.50%	0.02%
3	Long Term Debt-fixed	2,131,302	38.99%	12,210	(6,377)	2,137,135	37.04%	0.749997	1,602,845	34.02%	5.73%	1.95%
4	Short Term Debt	72,288	1.32%	(38,652)	(216)	33,420	0.58%	0.752484	25,148	0.53%	4.04%	0.02%
5	Total for Financial	4,952,901				5,770,135	100.00%					
6	Active Customer Deposits	136,401	2.50%		(408)	135,993		0.749884	101,979	2.16%	5.92%	0.13%
7	ITC-Total	26,572	0.49%	1,587	(80)	28,079		0.749777				
8	Equity								13,485	0.29%	12.70%	0.04%
9	Debt								7,568	0.16%	5.83%	0.01%
10	Deferred Income Taxes	407,236	7.45%	6,596	(1,218)	412,614		0.749853	309,400	6.57%	0.00%	0.00%
11	FAS 109 DIT	(56,547)	-1.03%	(5,098)	169	(61,476)		0.749691	(46,088)	-0.98%	0.00%	0.00%
12	Total	5,466,563	100.00%	835,138	(16,356)	6,285,345			4,711,668	100.00%		9.43%

Line No.	Item	Amount
13	Rate Base	$ 4,640,452
14	Revised Rate of Return	9.43%
15	Return on Rate Base	$ 437,514
16	Less Current Return per A-1	314,983
17	Return Deficiency per A-1	$ 122,531
18	NOI Multiplier	1.632
19	Adjusted Revenue Increase	199,970
20	Less Requested Increase [1]	204,945
21	Revenue Impact of Eliminating CR3 debt adjustment	$ (4,975)

[1] Corrected for error in removing non-utility equity as shown on Exhibit__(SLB-3), page 1 of 3.

Progress Energy Florida
Cost of Capital Adjustments

Capital Structure Per D-1a, as corrected for Non-Utility Equity Adjustment Error

	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
Common Equity	2,715,814	49.68%	858,495	(8,126)	3,566,183	0.749341	2,672,287	57.72%	12.80%	7.39%
Preferred Stock	33,497	0.61%		(100)	33,397	0.749888	25,044	0.54%	4.50%	0.02%
Long Term Debt-fixed	2,131,302	38.99%	(97,379)	(6,377)	2,027,546	0.749997	1,520,653	32.85%	5.73%	1.88%
Short Term Debt	72,288	1.32%	(38,652)	(216)	33,420	0.752484	25,148	0.54%	4.04%	0.02%
Active Customer Deposits	136,401	2.50%		(408)	135,993	0.749884	101,979	2.20%	5.92%	0.13%
ITC-Total	26,572	0.49%	1,587	(80)	28,079	0.749777		0.00%		
Equity		0.00%		-			13,485	0.29%	12.70%	0.04%
Debt		0.00%		-			7,568	0.16%	5.83%	0.01%
Deferred Income Taxes	407,236	7.45%	6,596	(1,218)	412,614	0.749853	309,400	6.68%	0.00%	0.00%
FAS 109 DIT	(56,547)	-1.03%	(5,098)	169	(61,476)	0.749691	(46,088)	-1.00%	0.00%	0.00%
Total	5,466,563	100.00%	725,549	(16,356)	6,175,756		4,629,476	100.00%		9.49%

Remove 50 basis point adder:

	Ratio	Cost Rate	Weighted Cost Rate
Common Equity	57.72%	12.30%	7.10%
Preferred Stock	0.54%	4.50%	0.02%
Long Term Debt-fixed	32.85%	5.73%	1.88%
Short Term Debt	0.54%	4.04%	0.02%
Active Customer Deposits	2.20%	5.92%	0.13%
ITC-Total			
Equity	0.29%	12.70%	0.04%
Debt	0.16%	5.83%	0.01%
Deferred Income Taxes	6.68%	0.00%	0.00%
FAS 109 DIT	-1.00%	0.00%	0.00%
Total	100.00%		9.21%

Remove 90 basis point adder

	Ratio	Cost Rate	Weighted Cost Rate
Common Equity	57.72%	11.40%	6.58%
Preferred Stock	0.54%	4.50%	0.02%
Long Term Debt-fixed	32.85%	5.73%	1.88%
Short Term Debt	0.54%	4.04%	0.02%
Active Customer Deposits	2.20%	5.92%	0.13%
ITC-Total			
Equity	0.29%	12.70%	0.04%
Debt	0.16%	5.83%	0.01%
Deferred Income Taxes	6.68%	0.00%	0.00%
FAS 109 DIT	-1.00%	0.00%	0.00%
Total	100.00%	0.00%	8.69%

Impact on Revenue Requirement	Per Company as Adj for Non-Utility Error	Less 50 basis point adder	Per Company as Adj for Non-Utility Error	ROE at 11.4% without adders	Impact of Eliminating 90 basis point adder
Jurisdictional Rate Base	4,640,452	4,640,452	4,640,452	4,640,452	
Rate of Return	9.49%	9.21%	9.49%	8.69%	
Jurisdictional NOI Needed	440,562	427,169	440,562	403,061	
Jurisdictional NOI per Co	314,983	314,983	314,983	314,983	
NOI Deficiency	125,579	112,186	125,579	88,078	
NOI Multiplier	1.632	1.632	1.632	1.632	
Revenue Increase	204,945	183,088	204,945	143,744	
Revenue Impact		21,858		61,201	39,344
		10.67%		29.86%	19.20%

Progress Energy Florida
Cost of Capital Adjustments

Capital Structure Before Off-Balance Sheet Obligation Adjustment by Rating Agencies

Line No.	Class	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Ratio for Financial Reporting
1	Common Equity	2,715,814	54.83%	858,495	(8,126)	3,566,183	63.00%
2	Preferred Stock	33,497	0.68%		(100)	33,397	0.59%
3	Long Term Debt-fixed	2,131,302	43.03%	(97,379)	(6,377)	2,027,546	35.82%
4	Short Term Debt	72,288	1.46%	(38,652)	(216)	33,420	0.59%
5	Total for Financial	4,952,901				5,660,546	100.00%

Capital Structure After Off-Balance Sheet Obligation Adjustment by Rating Agencies

Line No.	Class	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Ratio for Financial Reporting
6	Common Equity	2,715,814	54.83%	858,495	(8,126)	3,566,183	55.57%
7	Preferred Stock	33,497	0.68%		(100)	33,397	0.52%
8	Long Term Debt-fixed	2,131,302	43.03%	659,621	(6,377)	2,784,546	43.39%
9	Short Term Debt	72,288	1.46%	(38,652)	(216)	33,420	0.52%
10	Total for Financial	4,952,901				6,417,546	100.00%

Progress Energy Florida
Cost of Capital Adjustments

Capital Structure Per D-1a as corrected for Non-Utility Equity Adjustment Error

	Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
Common Equity	2,715,814	49.68%	858,495	(8,126)	3,566,183	0.749341	2,672,287	57.72%	12.80%	7.39%
Preferred Stock	33,497	0.61%		(100)	33,397	0.749888	25,044	0.54%	4.50%	0.02%
Long Term Debt-fixed	2,131,302	38.99%	(97,379)	(6,377)	2,027,546	0.749997	1,520,653	32.85%	5.73%	1.88%
Short Term Debt	72,288	1.32%	(38,652)	(216)	33,420	0.752484	25,148	0.54%	4.04%	0.02%
Active Customer Deposits	136,401	2.50%		(408)	135,993	0.749884	101,979	2.20%	5.92%	0.13%
ITC-Total	26,572	0.49%	1,587	(80)	28,079	0.749777		0.00%		
Equity		0.00%		-			13,485	0.29%	12.70%	0.04%
Debt		0.00%		-			7,568	0.16%	5.83%	0.01%
Deferred Income Taxes	407,236	7.45%	6,596	(1,218)	412,614	0.749853	309,400	6.68%	0.00%	0.00%
FAS 109 DIT	(56,547)	-1.03%	(5,098)	169	(61,476)	0.749691	(46,088)	-1.00%	0.00%	0.00%
Total	5,466,563	100.00%	725,549	(16,356)	6,175,756		4,629,476	100.00%		9.49%

Use the modified Cost of Common Equity	Ratio	Cost Rate	Weighted Cost Rate
Common Equity	57.72%	10.87%	6.27%
Preferred Stock	0.54%	4.50%	0.02%
Long Term Debt-fixed	32.85%	5.73%	1.88%
Short Term Debt	0.54%	4.04%	0.02%
Active Customer Deposits	2.20%	5.92%	0.13%
ITC-Total			
Equity	0.29%	12.70%	0.04%
Debt	0.16%	5.83%	0.01%
Deferred Income Taxes	6.68%	0.00%	0.00%
FAS 109 DIT	-1.00%	0.00%	0.00%
Total	100.00%		8.38%

Impact on Revenue Requirement	Per Company as Adj for Non-utility Error	Using Modified ROE
Jurisdictional Rate Base	4,640,452	4,640,452
Rate of Return	9.49%	8.38%
Jurisdictional NOI Needed	440,562	388,865
Jurisdictional NOI per Co	314,983	314,983
NOI Deficiency	125,579	73,882
NOI Multiplier	1.632	1.632
Revenue Increase	204,945	120,575
Revenue Impact of using modified ROE		84,370
		41.17%

Progress Energy Florida
Distribution O&M Expenses

Distribution Total O&M Estimates vs. Actual	2002	2003	2004	Total
2001 Estimated Distribution O&M Expenses [1]	$ 97,100	$ 97,100	$ 97,100	$ 291,300
Actual Distribution O&M Expenses [2]	$ 81,952	$ 92,964	$ 84,944	$ 259,859
Overestimate ($)	$ 15,148	$ 4,136	$ 12,156	$ 31,441
Overestimate (%)	18.5%	4.4%	14.3%	12.1%

Distribution Incremental O&M Estimates vs. Actual	2002	2003	2004	Total
2001 Estimated Expenditures on Distribution Initiatives [3]	$ 6,948,000	$ 6,948,000	$ 6,243,000	$ 20,139,000
Actual Expenditures on Distribution Initiatives [4]	$ 3,400,000	$ 3,200,000	$ 2,700,000	$ 9,300,000
Overestimate ($)	$ 3,548,000	$ 3,748,000	$ 3,543,000	$ 10,839,000
Overestimate (%)	104.4%	117.1%	131.2%	116.5%
Percent Actual to Estimated				46.2%

Recommended 2006 O&M Spending Levels	
Proposed 2006 Distribution Incremental Reliability Initiatives [5]	$ 18,650,000
Percent Actual to Estimated	46.2%
Recommended 2006 Incremental Distribution Reliability Initiatives	$ 8,612,394
Recommended Reduction in Incremental Distribution Reliability Initiatives	$ 10,037,606
Jurisdictional Allocation Factor (c-4, page 8)	99.761%
Jurisdictional Adjustment	$ 10,013,616

[1] Docket 000824-EI, Sipes direct testimony
[2] PEF FERC Form 1 Filings
[3] Docket 000824-EI, Exhibit RAS-1
[4] Exhibit DO-1
[5] Exhibit DM-2

Progress Energy Florida
Transmission O&M Expenses

Transmission Total O&M Estimates vs. Actual	**2002**	**2003**	**2004**	**Total**
2001 Estimated Transmission O&M Expenses [1]	$ 34,300	$ 34,300	$ 34,300	$ 102,900
Actual Transmission O&M Expenses [2]	$ 31,499	$ 27,659	$ 26,716	$ 85,874
Overestimate ($)	$ 2,801	$ 6,641	$ 7,584	$ 17,026
Overestimate (%)	8.9%	24.0%	28.4%	19.8%

Transmission Incremental O&M Estimates vs. Actual	**2002**	**2003**	**2004**	**Total**
2001 Estimated Expenditures on Transmission Initiatives [3]	$ 9,730,000	$ 9,730,000	$ 9,730,000	$ 29,190,000
Actual Expenditures on Transmission Initiatives [4]	$ 7,900,000	$ 8,300,000	$ 6,600,000	$ 22,800,000
Overestimate ($)	$ 1,830,000	$ 1,430,000	$ 3,130,000	$ 6,390,000
Overestimate (%)	23.2%	17.2%	47.4%	28.0%
Percent Actual to Estimated				78.1%

Recommended 2006 O&M Spending Levels	
Proposed 2006 Transmission Incremental Reliability Initiatives [5]	$ 10,000,000
Percent Actual to Estimated Based on Historical Average	78.1%
Recommended 2006 Incremental Transmission Reliability Initiatives	$ 7,810,894
Recommended Reduction in Incremental Transmission Reliability Initiatives	$ 2,189,106
Jurisdictional Allocation (Schedule C-4, page 6)	71.429%
Jurisdictional Revenue Impact	$ 1,563,656

[1] Docket 000824-EI, Rogers direct testimony
[2] PEF FERC Form 1 Filings
[3] Docket 000824-EI, Exhibit SSR-1
[4] Exhibit DO-1
[5] Exhibit RFD-3

Progress Energy Florida
Interest Coverage Ratios without CWIP

Description	Per Schedule D-9		Remove CWIP	
	Present Rates	Proposed Rates	Present Rates	Proposed Rates
Interest Coverage Ratios				
Including AFUDC	5.18	6.91	5.08	6.81
Excluding AFUDC	5.04	6.77	4.94	6.67
Interest	130,906	130,848	130,906	130,848
EBIT				
Including AFUDC	678,093	904,160	665,403	891,470
Excluding AFUDC	659,766	885,841	647,076	873,151

NOTES:

CWIP Impact	
CWIP in Rate Base	82,105
Rate of Return	9.49%
Tax gross-up factor	1.632
Revenue Impact	12,721
Less Reg. Assess & Uncollect.	31
EBIT	12,690
Breakdown of taxes	
Regulatory Assessment	0.0007200
Uncollectible Accounts	0.0017430
State	0.0548650
Federal	0.3299350
Total	0.3872630
Tax gross-up factor	1.63202157

Progress Energy Florida
Bad Debt Expense

Year	Gross Revenues (Retail)	Bad Debt Factor	Bad Debt
2001	2,795,612	0.123%	3,438
2002	2,724,244	0.123%	3,345
2003	2,830,809	0.170%	4,812
2004	3,124,103	0.159%	4,978
2006	3,612,553	0.174%	6,298
Avg 2001-2004		0.144%	5,194
Difference			**$ 1,104**

Source: Schedule C-11

Net Operating Income Multiplier per C-44	Per Company	Revised
Revenue Requirement	1	1
Gross Receipts Tax Rate	0	0
Regulatory Assessment	0.00072	0.00072
Bad Debt Rate	0.001743	0.00144
Net Before Income Taxes	0.997537	0.99784
State Income Tax Rate	0.055	0.055
State Income Tax	0.05486	0.05488
Net Before Federal Income Tax	0.94268	0.94296
Federal Income Tax Rate	0.35	0.35
Federal Income Tax	0.32994	0.33004
Revenue Expansion Factor	0.612737	0.61292
Net Operating Income Multiplier	1.63202	1.63153
FPL Claimed NOI deficiency from E-1		125,954
Required Increase		205,498
Requested Increase		205,556
Adjustment to Revenue Requirement		**$ 58**
Total Adjustment to Revenue Requirement		**$ 1,162**

EXHIBIT NO. ________ (SLB-9)
SHEREE L. BROWN – FRF
DOCKET NO. 050078-EI

Progress Energy Florida
Rate Case Expenses

1	Rate Case Expense	$ 1,500,000
2	Working Capital Component	2,250,000
3	Change in WACC [L18]	-
4	Return Component[L2 * 1.632*WACC]	348,618
5	Total Revenue Impact [L1+L6]	$ 1,848,618

6 Capital Structure with Elimination of Rate Case Expense Adjustment

		Co Total per Books	Ratio	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
7	Common Equity	2,715,814	49.68%	858,495	(9,244)	3,565,065	0.749341	2,671,449	57.73%	12.80%	7.39%
8	Preferred Stock	33,497	0.61%		(114)	33,383	0.749888	25,034	0.54%	4.50%	0.02%
9	Long Term Debt-fixed	2,131,302	38.99%	(97,379)	(7,254)	2,026,669	0.749997	1,519,996	32.84%	5.73%	1.88%
10	Short Term Debt	72,288	1.32%	(38,652)	(246)	33,390	0.752484	25,125	0.54%	4.04%	0.02%
11	Active Customer Deposits	136,401	2.50%		(464)	135,937	0.749884	101,937	2.20%	5.92%	0.13%
12	ITC-Total	26,572	0.49%	1,587	(90)	28,069	0.749777		0.00%		
13	Equity		0.00%		-			13,480	0.29%	12.70%	0.04%
14	Debt		0.00%		-			7,565	0.16%	5.83%	0.01%
15	Deferred Income Taxes	407,236	7.45%	6,596	(1,386)	412,446	0.749853	309,274	6.68%	0.00%	0.00%
16	FAS 109 DIT	(56,547)	-1.03%	(5,098)	192	(61,453)	0.749691	(46,071)	-1.00%	0.00%	0.00%
17	Total	5,466,563	100.00%	725,549	(18,606)	6,173,506		4,627,790	100.00%		9.49%
18	D-1a WACC										9.49%
19	Change										0.00%

Progress Energy - Florida
Reported Hurricane Damage
(Data in Millions)

Year	Unadjusted Damage	2006$ Damage	/1	Excluding 2004
1994	0.001	0.001		0.001
1995	4.367	5.743		5.743
1996	0.007	0.009		0.009
1997	1.159	1.447		1.447
1998	-	-		-
1999	4.506	5.420		5.420
2000	2.102	2.446		2.446
2001	5.896	6.672		6.672
2002	-	-		-
2003	0.715	0.779		0.779
2004	366.000	388.289		

Total 1994-2003	22.517
Category 1 and 2 Annual Average	2.252
2004 Average per Storm	129.43
Category 3 to 5 Annual Average	12.943
Total	**15.195**

/1 Escalated at CPI.

Florida Direct Hit Landfall Hurricanes 1900-2000

Category	Northeast Florida	Northwest Florida	Total
1	2	10	12
2	7	8	15
3	0	7	7
4	0	0	0
5	0	0	0
Total	9	25	34
Major	0	7	7

Per National Oceanic and Atmospheric Administration

Category 3 through 5 -100 years	7
Category 3 through 5, 2004	3
Total Category 3 through 5-104 years	10
Frequency, one every 10.4 years	10.4
Round to 10 years	

Progress Energy Florida
Storm Damage Reserve Accrual

1	Storm Damage Accrual per Company	$	50,000,000
2	Storm Damage Accrual Recommended	$	15,200,000
3	Reduction in Test Year Expenses	$	34,800,000
4	Working Capital Component per Co.		31,265,000
5	Working Capital Component Revised		13,865,000
6	Reduction in Working Capital Liabilities		17,400,000
7	Return Component[L12 * 1.632*WACC]		2,695,964
8	Total Revenue Impact [L3-L7]	$	32,104,036
9	Jurisdictional Allocation [Schedule C-4]		96.949%
10	Jurisdictional Revenue Impact	$	31,124,542

Note:
No adjustments to DIT were assumed, since the Company did not make an adjustment to ADIT in its specific cost of capital adjustments on Schedule D-1b. Prorata adjustments to the cost of capital did not affect the weighted average cost of capital.

Progress Energy Florida
Storm Damage Reserve Accrual

End-of-Year Storm Reserve Balance

		Per Company	Corrected		Correction
1	Beginning Balance, Storm Reserve	6,515,000	6,515,000		
2	Accrual	6,000,000	6,000,000		
3	Ending Balance	12,015,000	12,515,000		
4	Average Balance	9,265,000	9,515,000		(250,000)
5	Revenue Impact [L4 x .0949 x 1.632]				(38,719)
6	Jurisdictional Allocation Factor				96.949%
7	Retail Jurisdictional Impact				(37,538)

Correction of Taxes on Schedule C-2

8	Jurisdictional Increase in Expense	42,658,000	42,658,000		
9	Income taxes	15,686,000	16,455,324		
10	Net Operating Income	(26,972,000)	(26,202,677)		769,324
11	Tax Gross Up				1.632
12	Effect on Test Year Revenue Requirement			$	1,255,536