ORIGINAL

TOM LEE
President

Harold McLean
Public Counsel

STATE OF FLORIDA
OFFICE OF PUBLIC COUNSEL

c/o THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
ROOM 812
TALLAHASSEE, FLORIDA 32399-1400
850-488-9330

EMAIL: OPC_WEBSITE@LEG.STATE.FL.US
WWW.FLORIDAOPC.GOV

ALLAN BENSE
Speaker

Joseph A. McGlothlin
Associate Public Counsel

July 13, 2005

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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

Dear Ms. Bayó:

Enclosed are an original and twenty-five (25) copies of the Direct Testimony of Donna DeRonne on behalf of the Office of Public Counsel for filing in the above-referenced docket.

Also enclosed is a 3.5 inch diskette containing the Direct Testimony of Donna DeRonne in Microsoft Word format. Please indicate receipt of filing by date-stamping the attached copy of this letter and returning it to this office. Thank you for your assistance in this matter.

Sincerely,

Joe A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

JAM/dsb
Enclosures

CMP ____
COM 5
CTR orig
ECR ____
GCL 2
OPC ____
MMS ____
RCA 1
SCR ____
SEC 1
OTH ____

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony of Donna DeRonne, has been furnished by electronic mail and U.S. Mail on this 13th day of July, 2005, to the following:

Jennifer Brubaker, Esquire
Felicia Banks, Esquire
Jennifer Rodan, Esquire
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Michael B. Twomey, Esquire
Post Office Box 5256
Tallahassee, FL 32314-5256

C. Everett Boyd, Jr., Esquire
Sutherland Asbill & Brennan LLP
2282 Killearn Center Blvd.
Tallahassee, FL 32309

James M. Bushee, Esquire
Daniel E. Frank, Esquire
Andrew K. Soto, Esquire
Sutherland Asbill & Brennan LLP
1275 Pennsylvania Avenue, NW
Washington, DC 20004-2415

John W. McWhirter, Jr., Esquire
McWhirter Reeves
400 North Tampa Street, Suite 2450
Tampa, FL 33601-3350

Timothy J. Perry, Esquire
McWhirter Reeves
117 S. Gadsden Street
Tallahassee, FL 32301

Robert Scheffel Wright, Esquire
John T. LaVia, III, Esquire
Landers & Parsons, P.A.
310 West College Avenue
Tallahassee, FL 32301

Karin S. Torain
PCS Administration, (USA), Inc.
Suite 400
1101 Skokie Blvd.
Northbrook, IL 60062

R. Alexander Glenn
Deputy General Counsel - Florida
Progress Energy Service Company, LLC
100 Central Avenue, Suite 1D
St. Petersburg, FL 33701

Gary L. Sasso, Esquire
James Michael Walls, Esquire
John T. Burnett, Esquire
Dianne M. Triplett, Esquire
Carlton Fields, P.A.
Post Office Box 34239
Tampa, FL 33601-3239

HAROLD MCLEAN
PUBLIC COUNSEL

Joseph A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Progress Energy Florida, Inc.	)))	DOCKET NO. 050078-EI Filed July 13, 2005

DIRECT TESTIMONY OF

DONNA DERONNE, CPA

ON BEHALF OF

THE OFFICE OF PUBLIC COUNSEL

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DIRECT TESTIMONY OF DONNA DERONNE

ON BEHALF OF THE CITIZENS OF FLORIDA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PROGRESS ENERGY FLORIDA, INC.

DOCKET NO. 050078-EI

I. INTRODUCTION

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

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

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

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

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

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

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

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

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

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

II. OVERALL FINANCIAL SUMMARY

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

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

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

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

Q. WOULD YOU PLEASE BRIEFLY DISCUSS SCHEDULE D?

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

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

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

III. <u>NET OPERATING INCOME MULTIPLIER</u>

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

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

IV. RECOMMENDED ADJUSTMENTS

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

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

Rate Case Expense

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

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

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

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

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

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

Q. PLEASE EXPLAIN.

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

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

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

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

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

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

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

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

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

Uncollectible Expense

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

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

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

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

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

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

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

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

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

<u>Service Company Incentive Compensation</u>

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

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

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

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

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

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

Directors & Officers Liability Insurance Expense

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

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

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

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

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

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

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

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

NEIL Distributions

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

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

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

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

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

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

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

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

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

A. No, I do not.

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

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

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

Distribution Vegetation Management Expense

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

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

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

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

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

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

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

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

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

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

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

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

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

Property Tax Expense

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

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

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

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

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

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

<u>Impact of Adjustments to Plant in Service on Depreciation</u>

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

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

Income Tax Expense

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

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

Interest Synchronization

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

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

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

Separation of Winter Park System

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

PROGRESS ENERGY FLORIDA
DOCKET NO. 050078-EI

SCHEDULES OF DONNA DERONNE
TABLE OF CONTENTS

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Docket No. 050078-EI
Donna DeRonne Exh. ___ (DD-1)
Revenue Requirement

Revenue Requirement
(Thousands of Dollars)

Schedule A

Line No.	Description	Per Company Amount (A)	Per OPC Amount (B)	Col. (B) Reference:
1	Jurisdictional Adjusted Rate Base	4,640,452	4,397,330	Schedule B-1
2	Required Rate of Return	9.500%	6.573%	Schedule D
3	Jurisdictional Income Required	440,937	289,034	Line 1 x Line 2
4	Jurisdictional Adj. Net Operating Income	314,983	509,989	Schedule C-1
5	Income Deficiency (Sufficiency)	125,954	(220,955)	Line 3 - Line 4
6	Earned Rate of Return	6.788%	11.598%	Line 4 / Line 1
7	Net Operating Income Multiplier	1.632000	1.631533	Schedule A-1
8	Revenue Deficiency (Sufficiency)	205,557	(360,496)	Line 5 x Line 7

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Net Operating Income Multiplier

Docket No. 050078-EI
Donna DeRonne Exhibit N ___ DD-1)
Net Operating Income Multiplier

Schedule A-1

Line No.	Description	Percent	
1	Revenue Requirement	100.0000%	
2	Gross Receipts Tax Rate	0.0000%	
3	Regulatory Assessment Rate	0.0720%	
4	Bad Debt Rate, per OPC	0.1444%	Schedule C-2
5	Net Before Income Taxes	99.7836%	
6	State Income Tax Rate (Effective)	5.5000%	
7	State Income Tax	5.4881%	
8	Net Before Federal Income Tax	94.2955%	
9	Federal Income Tax Rate (Effective)	35.0000%	
10	Federal Income Tax	33.0034%	
11	Revenue Expansion Factor	61.2921%	
12	Net Operating Income Multiplier	1.631533	

Source:
Company MFR Sch. C-44.

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Docket No. 050078-EI
Donna DeRonne Exh.__(DD-1)
Schedule B-1
Page 1 of 2

Adjusted Rate Base
(Thousands of Dollars)

Line No.	Rate Base Components	Adjusted Juris. Total Amount per Company	OPC Adjustments	Adjusted Juris. Total Amount per OPC
		(A)	(B)	(C)
1	Plant In Service	8,363,233	(104,158)	8,259,075
2	Accum. Depreciation & Amortization	4,051,946	(85,284)	3,966,662
3	Net Plant In Service	4,311,287		4,292,413
4	Construction Work In Progress	82,105	(82,105)	-
5	Plant Held for Future Use	6,054	(4,937)	1,117
6	Nuclear Fuel (Net)	57,413		57,413
7	Net Utility Plant	4,456,859		4,350,943
8	Working Capital Allowance	183,593	(137,206)	46,387
9	Other Rate Base Items	-		-
10	Total Rate Base	4,640,452	(243,122)	4,397,330

Source/Notes:
Col. (A): Company MFR Schedule B-1
Col. (B): See Schedule B-1, page 2

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Adjusted Rate Base - Summary of Adjustments
(Thousands of Dollars)

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Adjusted Rate Base - Summary of Adjustments

Schedule B-1
Page 2 of 2

Line No.	Adjustment Title	Reference	Total Adjustment	Jurisdictional Separation Factor	Jurisdictional Amount
	Plant in Service Adjustments:				
1	Overstatement of Projected Plant in Service	H. Larkin, Sch. B-1	(139,698)	0.92671	(129,459)
2	Charging Practices - 50% Removal	H. Schultz, Sch. 6			25,301
3	*Total Plant in Service*				(104,158)
4					
5	**Accumulated Depreciation Adjustments:**				
6	Impact of Adjustments to PIS on Depreciation	D. DeRonne, Sch. C-5	(2,473)	0.93960	(2,323)
7	Flow-Back Portion of Excess Depreciation Reserve	Sch. C-1, p. 2, line 19 @ 50%	(89,246)	0.93960	(83,856)
8	Charging Practices - 50% Removal	H. Schultz, Sch. 6			895
9	*Total Accumulated Depreciation*				(85,284)
10					
11	**Construction Work in Progress**				
12	Remove Construction Work in Progress	H. Larkin - Testimony	(98,597)	0.83273	(82,105)
13					
14	**Plant Held For Future Use:**				
15	Reduction to Plant Held for Future Use	H. Larkin - Testimony	(6,459)	0.76430	(4,937)
16					
17	**Working Capital Adjustments:**				
18	OPC Adjustments to Working Capital	H. Larkin, Sch. B-2	(142,056)	various	(137,206)
19					
20	*Total Working Capital*				(137,206)

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Adjusted Net Operating Income

Adjusted Net Operating Income
(Thousands of Dollars)

Schedule C-1
Page 1 of 2

Line No.	Description	Adjusted Jurisdictional Total per Company	OPC Adjustments	Adjusted Jurisdictional Total per OPC
		(A)	(B)	(C)
	Operating Revenues:			
1	Sales of Electricity	1,389,673		1,389,673
2	Other Operating Revenues	92,549		92,549
3	Total Operating Revenues	1,482,222		1,482,222
	Operating Expenses:			
4	Fuel and Net Interchange	10,214		10,214
5	Other Operation & Maintenance	601,922	(83,717)	518,205
6	Depreciation & Amortization	310,893	(200,697)	110,196
7	Taxes Other Than Income	113,631	(7,701)	105,930
8	Current/Deferred Income Taxes	136,152	97,109	233,261
9	Charge Equivalent to Investment Tax Credit	(5,499)		(5,499)
10	(Gain)/Loss on Disposition of Utility Property	(74)		(74)
11	Total Operating Expenses	1,167,239		972,233
12	Net Operating Income	314,983		509,989

Source/Notes:
Col. (A): Company MFR Schedule C-1
Col. (B): See Schedule C-1, page 2

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Net Operating Income - Summary of Adjustments
(Thousands of Dollars)

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Net Operating Income - Summary of Adjustments

Schedule C-1
Page 2 of 2

Line No.	Adjustment Title	Reference	Total Adjustment	Jurisdictional Separation Factor	Jurisdictional Amount
1	**Operating Expense Adjustments:**				
2	Operation and Maintenance:				
3	Reduction to Storm Fund Accrual	H. Schultz, Sch. 1	(37,500)	0.96949	(36,356)
4	Reduction to Incentive Compensation	H. Schultz, Sch. 2	(7,967)	various	(7,143)
5	Payroll Expense	H. Schultz, Sch. 3	(7,985)	0.90840	(7,254)
6	Healthcare Expense	H. Schultz, Sch. 5	(3,046)	0.90840	(2,767)
7	Charging Practices - 50% Removal	H. Schultz, Sch. 6			(17,094)
8	Rate Case Expense	D. DeRonne - Testimony	(1,500)	1.00000	(1,500)
9	Uncollectible Expense	D. DeRonne, Sch. C-2	(1,080)	1.00000	(1,080)
10	Remove Service Company Incentive Compensation	D. DeRonne - Testimony	(5,671)	0.87872	(4,983)
11	Remove Directors & Officers Liability Insurance Expense	D. DeRonne - Testimony	(1,953)	0.92421	(1,805)
12	Increase NEIL Distributions	D. DeRonne - Testimony	(639)	0.93535	(598)
13	Vegetation Management Expense	D. DeRonne, Sch. C-3	(3,145)	0.99761	(3,137)
14					-
15					-
16	*Total Operation and Maintenance*				(83,717)
17					
18	Depreciation and Amortization:				
19	Flow-Back Portion of Excess Depreciation Reserve	J. Pous	(178,493)	0.92209	(164,586)
20	Flow-Back of Excess Decommissioning Funds	J. Pous	(32,439)	1.00000	(32,439)
21	Impact of Adjustments to PIS on Depreciation	D. DeRonne, Sch. C-5	(4,945)	0.94062	(4,652)
22	Charging Practices - 50% Removal	H. Schultz, Sch. 6			980
23	*Total Depreciation and Amortization*				(200,697)
24					
25	Taxes Other Than Income:				
26	Payroll Taxes	H. Schultz, Sch. 4	(3,314)	0.92421	(3,063)
27	Property Tax Expense	D. DeRonne, Sch. C-4	(4,198)	0.92619	(3,888)
28	Charging Practices - 50% Removal	H. Schultz, Sch. 6			(750)
29	*Total Taxes Other Than Income*				(7,701)
30					
31	Income Taxes:				
32	Impact of Other Adjustments	D. DeRonne, Sch. C-6			112,683
33	Interest Synchronization Adjustment	D. DeRonne, Sch. C-7			(15,574)
34	*Total Income Tax*				97,109

Notes:
Jurisdictional Separation factors from MFR Schedule C-4 or other schedules within the Company's filing.

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Uncollectible Expense
(Thousands of Dollars)

Docket No. 050078-EI
Donna DeRonne Exhibit No._ (DD-1)
Uncollectible Expense

Schedule C-2
Page 1 of 1

Line No.	Year	Net Write-Offs	Adjusted Gross Revenues	Bad Debt Factor
1	2001	3,438	2,795,612	0.123%
2	2002	3,345	2,724,244	0.123%
3	2003	4,812	2,830,809	0.170%
4	2004	4,978	3,124,103	0.159%
5	Total 2001 - 2004	16,573	11,474,768	0.144%
7	2006 Adjusted Gross Revenues, per PEF			3,612,553
8	OPC Recommended Bad Debt Rate			0.144%
9	OPC Recommended Bad Debt Expense			5,218
10	Bad Debt Expense (Net Write-Offs), per PEF			6,298
11	Reduction to Bad Debt Expense			(1,080)

Source:
Amounts from Company MFR Sch. C-11.

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Distribution Vegetation Management Expense
(Thousands of Dollars)

Docket No. 050078-EI
Donna DeRonne Exhibit No.__ (DD-1)
Distribution Vegetation Management Expense

Schedule C-3

Line No.	Description	Amount	% Change
	Annual Distribution Vegetation Management Expense:		
1	2000	9,600	
2	2001	9,500	-1.0%
3	2002	13,200	38.9%
4	2003	14,520	10.0%
5	2004	15,410	6.1%
6	2005 Budgeted	15,260	-1.0%
7	2006 Projected (Requested)	26,260	72.1%
8	Percentage Change Between Actual 2004 and Requested 2006		70.4%
9	Actual 2004 Distribution Vegetation Management Expense	15,410	Line 5
10	Allowance for 50% Above 2004 Actual Expense	7,705	Line 9 x 50%
11	Recommended Distribution Vegetation Management Expense	23,115	
12	Reduction to Projected Test Year Expense	(3,145)	Line 11 - Line 7

Source:

Lines 1 - 7: Response to OPC Interrogatory No. 111.

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Property Tax Expense
(Thousands of Dollars)

Docket No. 050078-EI
Donna DeRonne Exh. _ (DD-1)
Property Tax Expense

Schedule C-4

Line No.	Description	Amount	
1	OPC Reduction to December 31, 2005 PIS Balance	(137,485)	Line A.3, below
2	OPC Reduction to PHFFU	(6,459)	H. Larkin - Testimony
	Remove 2 Turbines in Materials & Supplies	(46,800)	H. Larkin, Sch. B-2
3	Remove Above-Market Affiliate Transfer from Utility Plant	(23,361)	MFR. Sch. B-1, OPC Interrog. 226
4	Reduction to Net Taxable Plant	(214,105)	
5	Assessed Value as % of Net Plant, per Co.	108.50%	OPC Interrog. 53
5	Reduction to Projected Assessed Value	(232,304)	
6	Effective Millage Rate, per Co.	0.01807	OPC Interrog. 53
7	Reduction to Property Tax Expense	(4,198)	
	Calculation of OPC Reduction to 12/31/05 PIS Balance:		
A.1	Taxable Plant In Service Balance @ 12/31/05, per PEF	9,033,198	OPC Interrog. 53
A.2	% Projected PIS Balance is Overstated, per OPC	1.52%	H. Larkin, Sch. B-1
A.3	Amount 12/31/05 PIS Balance is Overstated	137,485	

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Impact of Adjustments to PIS on Depreciation

Docket No. 050078-EI
Donna DeRonne Exhibit No.__ (DD-1)
Impact of Adjustments to PIS on Depreciation

Schedule C-5

Line No.	Description	Amount	
1	Overstatement of Projected Plant in Service	(139,698)	H. Larkin, Sch. B-1
2	Composite Depreciation Rate	3.54%	(A)
3	Reduction to Depreciation Expense	(4,945)	
4	Reduction to Accumulated Depreciation	(2,473)	

Source:
(A) PEF Exhibit No.__(RHB-7), Vol. 1 of 3, page 1-13.

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Income Tax Expense

Income Tax Expense
(Thousands of Dollars)

Schedule C-6

Line No.	Description	Amount
1	Jurisdictional Operating Income Adjustments (1)	(292,115)
2	Composite Income Tax Rate	38.575%
3	Adjustment to Income Tax Expense	112,683

Source:
(1) Schedule C-1, p. 2

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Interest Synchronization Adjustment
(Thousands of Dollars)

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Interest Synchronization Adjustment

Schedule C-7

Line No.	Description	Amount	
1	Jurisdictional Rate Base, per OPC	4,397,330	Schedule B-1
2	Weighted Cost of Debt	3.07%	Schedule D
3	Interest Deduction, per OPC	134,947	
4	Jurisdictional Interest Deduction, per PEF	94,573	MFR Sch. C-4, p. 15
5	Increase (Decrease) in Deductible Interest	40,374	
6	Consolidated Tax Rate	38.575%	
7	Reduction (Increase) in Income Tax Expense	15,574	

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Overall Cost of Capital, per OPC

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Overall Cost of Capital, per OPC

Schedule D
Page 1 of 2

Line No.	Description	Amounts Adjusted to Reflect OPC Cap. Ratios	OPC Rate Base & DIT Adjustments	Per OPC Adjusted Amounts	Ratio	Per OPC Cost Rate	Weighted Cost
		(A)	(B)	(C)	(D)	(E)	(F)
1	Common Equity	1,778,700	(112,126)	1,666,574	37.89%	9.10%	3.45%
2	Preferred Equity	21,276	(1,341)	19,935	0.45%	4.58%	0.02%
3	Long Term Debt	2,297,841	(144,851)	2,152,990	48.95%	5.73%	2.80%
4	Short Term Debt	157,445	(9,925)	147,520	3.35%	4.04%	0.14%
5	Customer Deposits	101,979	(6,429)	95,550	2.17%	5.92%	0.13%
6	Investment Tax Credit - Equity	13,485	(850)	12,635	0.29%	9.10%	0.03%
7	Investment Tax Credit - Debt	7,568	(477)	7,091	0.16%	5.73%	0.01%
8	Deferred Income Taxes	309,400	29,971	339,371	7.72%	0.00%	0.00%
9	FAS 109 DIT - Net	(46,088)	2,905	(43,183)	-0.98%	0.00%	0.00%
10	Total Capital Structure	4,641,606	(243,122)	4,398,484	100.00%		6.57%

Source/Reference:

Cols. (A) & (E): Amounts are sponsored by Citizens' witness James A. Rothschild and may be found on Sch. JAR 1, page 2, included with Mr. Rothschild's testimony.

Cols. (B), (C) & (D): See page 2

PROGRESS ENERGY FLORIDA
Projected Test Year Ended December 31, 2006

Docket No. 050078-EI
Donna DeRonne Exh. __ (DD-1)
Overall Cost of Capital, per OPC

Overall Cost of Capital, per OPC
- Allocation of DIT and Rate Base Adjustments in Capital Structure

Schedule D
Page 2 of 2

		Adjusted Amounts to Reflect OPC Capitalzation Ratio	OPC Adj. to Deferred Income Taxes	Adjusted Amount	Adjusted Capital Ratio	Allocation of Remaining Rate Base Adjustments	Total OPC Adjustments
		(A)	(B)	(C)	(D)	(E)	(F)
1	Common Equity	1,778,700		1,778,700	37.89%	(112,126)	(112,126)
2	Preferred Equity	21,276		21,276	0.45%	(1,341)	(1,341)
3	Long Term Debt	2,297,841		2,297,841	48.95%	(144,851)	(144,851)
4	Short Term Debt	157,445		157,445	3.35%	(9,925)	(9,925)
5	Customer Deposits	101,979		101,979	2.17%	(6,429)	(6,429)
6	Investment Tax Credit - Equity	13,485		13,485	0.29%	(850)	(850)
7	Investment Tax Credit - Debt	7,568		7,568	0.16%	(477)	(477)
8	Deferred Income Taxes	309,400	52,804	362,204	7.72%	(22,833)	29,971
9	FAS 109 DIT - Net	(46,088)		(46,088)	-0.98%	2,905	2,905
10							
11	Total Capital Structure	4,641,606		4,694,410	100.00%		(243,122)
12							
13	Citizens Adjustments to Rate Base		(243,122)	Sch. B-1			
14	Adjustment to Deferred Income Tax **		52,804				
15	Remaining Amount to Spread to						
16	All components of capital structure		(295,926)				

** Adjustment to Deferred Income Taxes sponsored by Citizens witness Hugh Larkin, Jr.

APPENDIX I
QUALIFICATIONS OF DONNA DERONNE, C.P.A.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and regulatory consultant in the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated with honors from Oakland University in Rochester, Michigan in 1991. I have been employed by the firm of Larkin & Associates, PLLC, since 1991. As a certified public accountant and regulatory consultant with Larkin & Associates, PLLC, my duties have included the analysis of utility rate cases and regulatory issues, researching accounting and regulatory developments, preparation of computer models and spreadsheets, the preparation of testimony and schedules and testifying in regulatory proceedings. I have also developed and conducted five training programs on behalf of the Department of Defense - Navy Rate Intervention Office on measuring the financial capabilities of firms bidding on Navy assets and one training program on calculating the revenue requirement for municipal owned water and wastewater utilities. A partial listing of cases which I have participated in are included below:

Performed Analytical Work in the Following Cases:

Docket No. 92-06-05	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Docket No. R-00922428	The Pennsylvania American Water Company Pennsylvania Public Utility Commission
Cause No. 39498	PSI Energy, Inc. Before the State of Indiana - Indiana Utility Regulatory Commission
Docket No. 6720-TI-102	Wisconsin Bell, Inc. Wisconsin Citizens' Utility Board
Docket No. 90-1069 (Remand)	Commonwealth Edison, Inc. Before the Illinois Commerce Commission
Docket Nos. 920733-WS & 920734-WS	General Development Utilities, Inc. - Port Labelle and Silver Springs Shores Divisions. Before the Florida Public Service Commission
Case No. PUE910047	Virginia Electric and Power Company (State Corporation Commission)
Docket No. U-1565-91-134	Sun City Water Company Residential Utility Consumer Office
Docket No. 930405-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. UE-92-1262	Puget Sound Power & Light Company Before the Washington Utilities & Transportation Commission
Docket No. R-932667	Pennsylvania Gas & Water Company Before the Pennsylvania Public Utility Commission
Docket No. 7700	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. R-00932670	Pennsylvania American Water Company Pennsylvania Public Utility Commission

Case No. 78-T119-0013-94	Guam Power Authority vs. U.S. Navy Public Works Center, Guam - Assisting the Department of Defense in the investigation of a billing dispute.
Case No. 90-256	South Central Bell Telephone Company Before the Kentucky Public Service Commission
Case No. 94-355	Cincinnati Bell Telephone Company Before the Kentucky Public Service Commission
Docket No. 7766	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. 2216	Narragansett Bay Commission On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Docket No. 94-0097	Citizens Utilities Company, Kauai Electric Division Before the Public Utilities Commission of the State of Hawaii
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. E-1032-95-433	Citizens Utilities Company - Arizona Electric Division Before the Arizona Corporation Commission
Docket No. R-00973947	United Water Pennsylvania Before the Pennsylvania Public Utilities Commission
Docket No. 95-0051	Hawaiian Storm Damage Reserve Case Before the Public Utilities Commission of the State of Hawaii
Application Nos. 96-08-070, 96-08-071, 96-08-072	Pacific Gas & Electric Company, Southern California Edison Company & San Diego Gas & Electric Co.; Phases I & II; Before the California Public Utilities Commission
Docket No. E-1072-97-067	Southwestern Telephone Company Before the Arizona Corporation Commission
Docket No. 920260-TL	BellSouth Telecommunications Inc. - Florida On Behalf of the Florida Office of Public Counsel

Docket No. R-00973953	PECO Energy Company Before the Pennsylvania Public Utilities Commission
Docket No. 5983	Green Mountain Power Corporation Before the Vermont Public Service Board
Case No. PUE-9602096	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-34930705	Black Mountain Gas Division - Northern States Power Before the Arizona Corporation Commission
Docket No. T-01051B-99-105*	US West/Qwest Corporation Before the Arizona Corporation Commission
Docket No. 98-10-019	Verizon Audit Report on Behalf of California Office of Ratepayers Advocates
Docket No. 991437-WU*	Wedgefield Utilities, Inc. Before the Florida Public Service Commission
Docket No. 99-057-20*	Questar Gas Company Before the Utah Public Service Commission
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. ER02080614	Rockland Electric Company Before the New Jersey Board of Public Service
Docket No. 5841/5859	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Formal Case No. 1016	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Application No. 02-12-028	San Diego Gas & Electric Company Before the California Public Utilities Commission

Docket No. 03-2035-02**	PacifiCorp - Utah Operations Before the Public Service Commission of Utah
Docket No. 2004-0007-0011-0001	Intercoastal Utilities, Inc. Before the St. Johns County Water & Sewer Authority

Submitted Testimony in the Following Cases

Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Case No. 94-0035-E-42T	Monongahela Power Company Before the Public Service Commission of West Virginia
Case No. 94-0027-E-42T	Potomac Edison Company Before the Public Service Commission of West Virginia
Case No. 95-0003-G-42T*	Hope Gas, Inc. Before the West Virginia Public Service Commission
Case No. 95-0011-G-42T*	Mountaineer Gas Company Before the West Virginia Public Service Commission
Docket No. 950495-WS	Southern States Utilities Before the Florida Public Service Commission
Docket No. 960451-WS	United Water Florida Before the Florida Public Service Commission
Docket No. 5859	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board

Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 98-01-02	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 98-07-006	San Diego Gas and Electric Company Public Utilities Commission of the State of California
Docket No. 99-04-18 Phase I	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 99-04-18 Phase II	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 99-09-03 Phase I	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 99-09-03 Phase II	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 00-12-01	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 6460*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. G-01551A-00-0309	Southwest Gas Corporation Arizona Corporation Commission
Docket No. 01-05-19	Yankee Gas Services Company State of Connecticut Department of Public Utility Control

Docket No. 01-035-23 Interim (Oral testimony)	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 01-035-23**	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 010503-WU	Aloha Utilities, Inc. - Seven Springs Water Division Before the Florida Public Service Commission
Docket No. 000824-EI*	Florida Power Corporation Before the Florida Public Service Commission
Docket No. 001148-EI**	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 01-10-10	United Illuminating Company Connecticut Department of Public Utility Control
Docket No. 02-057-02*	Questar Gas Company Public Service Commission of Utah
Docket No. 020384-GU*	Tampa Electric Company d/b/a Peoples Gas System Before the Florida Public Service Commission
Docket No. 020010-WS	The Woodlands of Lake Placid, L.P. Before the Florida Public Service Commission
Docket No. 020071-WS	Utilities, Inc. of Florida Before the Florida Public Service Commission
Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 030438-EI*	Florida Public Utilities Company Before the Florida Public Service Commission
Docket No. 03-11-20	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 030102-WS	The Woodlands of Lake Placid, L.P. Before the Florida Public Service Commission

Docket No. 04-06-01*	Yankee Gas Services Company State of Connecticut, Department of Public Utility Control
Docket No. 6946 & 6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42*	PacifiCorp Before the Public Service Commission of Utah
Docket No. 05-03-17PH01	The Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 050045-EI	Florida Power & Light Company Before the Florida Public Service Commission

* Case Settled
** Testimony not filed/submitted due to settlement

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony of Donna DeRonne, has been furnished by electronic mail and U.S. Mail on this 13th day of July, 2005, to the following:

Jennifer Brubaker, Esquire
Felicia Banks, Esquire
Jennifer Rodan, Esquire
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Michael B. Twomey, Esquire
Post Office Box 5256
Tallahassee, FL 32314-5256

C. Everett Boyd, Jr., Esquire
Sutherland Asbill & Brennan LLP
2282 Killearn Center Blvd.
Tallahassee, FL 32309

James M. Bushee, Esquire
Daniel E. Frank, Esquire
Andrew K. Soto, Esquire
Sutherland Asbill & Brennan LLP
1275 Pennsylvania Avenue, NW
Washington, DC 20004-2415

John W. McWhirter, Jr., Esquire
McWhirter Reeves
400 North Tampa Street, Suite 2450
Tampa, FL 33601-3350

Timothy J. Perry, Esquire
McWhirter Reeves
117 S. Gadsden Street
Tallahassee, FL 32301

Robert Scheffel Wright, Esquire
John T. LaVia, III, Esquire
Landers & Parsons, P.A.
310 West College Avenue
Tallahassee, FL 32301

Karin S. Torain
PCS Administration, (USA), Inc.
Suite 400
1101 Skokie Blvd.
Northbrook, IL 60062

R. Alexander Glenn
Deputy General Counsel - Florida
Progress Energy Service Company, LLC
100 Central Avenue, Suite 1D
St. Petersburg, FL 33701

Gary L. Sasso, Esquire
James Michael Walls, Esquire
John T. Burnett, Esquire
Dianne M. Triplett, Esquire
Carlton Fields, P.A.
Post Office Box 34239
Tampa, FL 33601-3239

Joseph A. McGlothlin
Associate Public Counsel

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2282 Killearn Center Blvd.
Tallahassee, FL 32309

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Sutherland Asbill & Brennan LLP
1275 Pennsylvania Avenue, NW
Washington, DC 20004-2415

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McWhirter Reeves
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Carlton Fields, P.A.
Post Office Box 34239
Tampa, FL 33601-3239

HAROLD MCLEAN
PUBLIC COUNSEL

Joseph A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel