BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PETITION FOR INCREASE IN RATES BY PROGRESS ENERGY FLORIDA, INC. — DOCKET NO. 090079-EI
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PETITION FOR LIMITED PROCEEDING TO INCLUDE BARTOW REPOWERING PROJECT IN BASE RATES, BY PROGRESS ENERGY FLORIDA, INC. — DOCKET NO. 090144-EI
_____________________________/

PETITION FOR EXPEDITED APPROVAL OF THE DEFERRAL OF PENSION EXPENSES, AUTHORIZATION TO CHARGE STORM HARDENING EXPENSES TO THE STORM DAMAGE RESERVE, AND VARIANCE FROM OR WAIVER OF RULE 25-6.0143(1)(C), (D), AND (F), F. A. C., BY PROGRESS ENERGY FLORIDA, INC. — DOCKET NO. 090145-EU
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VOLUME 16

Pages 2208 through 2341

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN MATTHEW M. CARTER, II
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER KATRINA J. McMURRIAN
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP

DATE: Friday, September 25, 2009

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

PARTICIPATING: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
145	KHD-1	2241	2241
146	KHD-2	2241	2241
147	KHD-3	2241	2241
148	KHD-4	2241	2241
149	KHD-5	2241	2241
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173	DJL-1	2215	2240
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177	DJL-5	2215	2240
178	RLK-1	2270	2270
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181	MJM-1	2291	2291
182	MJM-2	2291	2291
183	MJM-3	2291	2291
184	MJM-4	2291	2291
185	MJM-5	2291	2291

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NUMBER:		ID.	ADMTD.
206	RH-1	2326	2326
207	RH-2	2326	2326
208	JYS-1	2331	2331
287	Excerpt of Deposition Transcript of Witness Dismukes	2243	2243
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290	Audit Findings	2322	2322

P R O C E E D I N G S

(Transcript follows in sequence from Volume 15.)

CHAIRMAN CARTER: Okay. Call your next witness.

MR. REHWINKEL: Mr. Chairman, the Citizens of Florida call Daniel J. Lawton to the stand.

CHAIRMAN CARTER: Okay.

MR. REHWINKEL: Were you sworn?

THE WITNESS: Yeah.

DANIEL J. LAWTON

was called as a witness on behalf of the Office of the Public Counsel and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. REHWINKEL:

Q. Mr. Lawton, could you state your name, address, employer and who you represent for the Commission's benefit, please?

A. Yes. My name is Daniel J. Lawton, L-A-W-T-O-N. My business address is 701 Brazos Street, Suite 500, Austin, Texas 78701. I'm self-employed with the Lawton law firm. I have other attorneys with me, and -- well, back at the firm working, hopefully. And I'm representing the Office of Public Counsel today.

Q. Mr. Lawton, did you prepare and file prefiled direct testimony consisting of some 21 pages?

A. I did.

Q. Do you have any corrections or changes to make to that testimony today?

A. None that I'm aware of.

Q. Okay. If I asked you the questions contained in your prefiled direct testimony, would the answers you gave therein be the same?

A. Yes.

MR. REHWINKEL: Mr. Chairman, I would ask that Mr. Lawton's prefiled direct testimony be moved into the record.

CHAIRMAN CARTER: The prefiled testimony of the witness will be inserted into the record as though read.

MR. REHWINKEL: Thank you.

BY MR. REHWINKEL:

Q. Mr. Lawton, did you also cause to be prepared five schedules, DL-1 through DL-5, identified as Exhibits 172 (sic.) through 177 for this docket?

A. I did.

CHAIRMAN CARTER: Mr. Rehwinkel, it would be 173 through 177.

MR. REHWINKEL: Yes. I'm sorry.

CHAIRMAN CARTER: No problem.

MR. REHWINKEL: My mistake. 173 through 177.

(Exhibits 173 through 177 marked for identification.)

BY MR. REHWINKEL:

Q. Do you have any corrections or changes to make to those schedules?

A. Yes. One, one correction on Schedule DJL-2. At Line 3 of Schedule DJL-2, the words "combined cycle" should be "other production." And Line 4 should be crossed out entirely. And the numbers still add up correctly. That was inadvertently included.

With that correction, these, these schedules are correct.

DIRECT TESTIMONY

Of

DANIEL J. LAWTON

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 090079-EI

SECTION I: <u>INTRODUCTION/BACKGROUND/SUMMARY</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton. My business address is 701 Brazos, Suite 500, Austin, Texas 78701.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility consulting business as an economist since 1983. Consulting engagements have included electric utility load and revenue forecasting, cost of capital analyses, revenue requirements/cost of service reviews, and rate design analyses in litigated rate proceedings before federal, state and local regulatory authorities. I have worked with municipal utilities developing electric rate cost of service studies for reviewing and setting rates. In addition, I have a law practice based in Austin, Texas. My main areas of legal practice include administrative law representing municipalities in electric and gas rate proceedings and other litigation and contract matters. I have included a brief description of my relevant educational background and professional work experience in Exhibit No. ___ (DJL-1).

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN RATE PROCEEDINGS?

A. Yes. A list of cases where I have previously filed testimony is included in Exhibit No. (DJL-1).

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Florida Office of Public Counsel (OPC).

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

A. My testimony will address the ratemaking policy and financial implications before the Florida Public Service Commission ("Commission") surrounding the over-recoveries of depreciation expenses and the associated excess depreciation reserve. I address and pull together the recommended excess depreciation reserve flow-back to customers proposal addressed in the testimony of Mr. Pous, the ratemaking treatment of Mr. Pous' proposal addressed in the cost of service testimony of OPC cost of service witness, and the implications of these adjustments on Progress Energy Florida ("Progress" or "Company") financial metrics addressed in Mr. Woolridge's testimony.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. As the evidence relates to the Progress depreciation reserve, I conclude and recommend the following:

1) Based on the Company's own evidence in this case, the Company's past depreciation rates have resulted in over-collecting at least $645,805,342 of depreciation expense resulting in an excess depreciation reserve of $645,805,642;

2) Mr. Pous' proposal to recommend a return to customers of $645,805,642 is conservative in light of the numerous additional adjustments to the requested level of depreciation expenses he recommends, which indicate the excess depreciation reserve is $858,679,855 or about 32.8% higher than the level of excess reserve recognized by the Company's own study;

3) Mr. Pous' recommendation to amortize the excess reserve over a four year period as an offset to current depreciation expense will result in correcting the excess reserve, and is consistent with sound regulatory policy and ratemaking guidelines;

4) Correcting the excess depreciation reserve over a four year period will not harm the Company's financial integrity or financial metrics; and

5) Mr. Pous' excess depreciation reserve correction proposal assures that the customers that paid the excessive depreciation charges will likely be the same customers that receive the benefits associated with correcting the excess depreciation reserve.

SECTION II: <u>DEPRECIATION EXPENSE AND DEPRECIATION RESERVES</u>

Q. PLEASE SUMMARIZE THE ISSUES THAT ARE BEFORE THE COMMISSION REGARDING THE EXCESS DEPRECIATION RESERVE.

A. There are three basic questions that are before the Commission in this case related to excess depreciation reserves. The first issue is: does an excess depreciation reserve exist and what is the amount of the excess reserve? The answer to this issue is addressed by Mr. Pous and he concludes an excess depreciation reserve exists in the amount of $645,805,342. Given that the Company's own evidence (depreciation study of Earl M. Robinson) supports this $645,805,342, there should be little controversy regarding this matter.

In addition, the $645,805,342 is a conservative estimate of the excess reserve. Mr. Pous recommends numerous additional adjustments to the Company's depreciation study – the results of which show an excess depreciation reserve of about $858 million or about $200 million above the level of the excess reserve adjustment acknowledged by the Company in this case.

The second issue is, how can the excess reserve be corrected? Again, Mr. Pous provides an answer by proposing a four year amortization of the excess reserve to assure that depreciation rates on a going forward basis are cost based.

The third issue: does the correction to the depreciation reserve allow the Company to maintain its financial integrity and is the correction consistent with sound ratemaking guidelines? I address this last issue in the following testimony. As is shown below, the correction to the excess depreciation reserve proposed in the testimony of the OPC witnesses is consistent with sound ratemaking policy, consistent with cost based rates, and does not impair the Company's financial integrity, and is a conservative estimate of the excess depreciation reserve level.

Q. PLEASE DESCRIBE THE EXCESS DEPRECIATION RESERVE YOU HAVE BEEN DISCUSSING.

A. As a result of the analysis by the Company and Mr. Pous' analyses of the Company's most current depreciation rate proposal, it has been determined that the Company's depreciation reserve has an excess or surplus of at least $645,805,342. This means that customers have overpaid, through rates and charges, depreciation expense. While I am not saying that the Company charged incorrect rates, instead past depreciation estimates in rates were high.

Q. PLEASE DESCRIBE DEPRECIATION EXPENSE.

A. Depreciation expense is a charge to a company's operating expense to reflect the annual recovery or amortization of previously expended capital investment. The annual depreciation expense or charge is a non-cash expenditure or charge included in a company's annual revenue requirement to recover the previously expended capital investment over the useful life of an asset investment.

Q. PLEASE EXPLAIN WHY YOU REFER TO DEPRECIATION AS A NON-CASH EXPENSE.

A. Depreciation expense does not involve a specific payment during the test period that is subject to reimbursement in revenue requirements. Unlike test period labor or operating and maintenance expenses, which are out-of-pocket cash payments, depreciation charges are not additional cash payments. While both cash expenditures such as labor and other ordinary costs and non cash depreciation charges are included on the income statement and in the revenue requirement for setting rates and charges, there are no additional cash flows out of the company for depreciation charges.

Rather than reducing cash for depreciation charges, the depreciation expense charged to cost of service is simultaneously debited from the balance sheet by increasing the accumulated provision for depreciation, which is an offset to gross plant accounts. Depreciation is the recovery of previous balance sheet or rate base investments – the return of capital.

Q. PLEASE EXPLAIN THE ACCUMULATED DEPRECIATION CONCEPT YOU ADDRESSED IN YOUR LAST ANSWER.

A. Accumulated depreciation is the measure of all previously recorded depreciation. Thus, an asset of $100 with a five year life, depreciated at $20 per year, after two years would have a gross plant value of $100 (the original cost), an accumulated depreciation of $40 (two years of depreciation recorded) and a net plant or rate base value of $60 ($100 gross plant less $40 of accumulated depreciation). Thus, the $40 accumulated depreciation in the above example is a record of the two years' depreciation payments on the return of invested capital to the Company.

Q. DOES THE ACCUMULATED RESERVE REPRESENT A CASH ACCOUNT OR POT OF DOLLARS IN RESERVE?

A. No. The reserve for accumulated depreciation reflects the recovery of depreciation from a book perspective. The annual dollars of depreciation expense recovered by a company will be comingled with all other funds and spent on salaries, dividends, or reinvested into the company to fund other capital projects.

Q. PLEASE EXPLAIN THE INTERRELATIONSHIP OF DEPRECIATION EXPENSE AND DEPRECIATION RESERVES.

A. Companies such as Progress make numerous capital investments in production, transmission, distribution and general plant facilities to generate, transmit and ultimately deliver electricity to a customer's delivery point, i.e. the meter. These various capital investments made by the Company are made with funds from capital markets (debt, equity, or preferred stocks), or internally generated funds from annual earnings.

Once these capital investments are made (if prudent and included by the regulator as part of invested capital used and useful in providing service), the utility, through cost of service and charges to customers, is allowed to earn a return <u>on</u> capital investment and a return <u>of</u> capital investment. The return on capital is the return necessary for the utility to recover its carrying costs (cost of borrowing) to fund these capital investments. The return of capital is the annual recovery of the initial capital investment over the useful life of the facility. This annual recovery of capital is depreciation expense.

As the annual return <u>of</u> capital (depreciation) is recovered by the Company, an equal and offsetting adjustment is made to invested capital rate base. In other words, as capital is recovered through rates, the amount of outstanding capital for which the company needs to earn a return, declines as it has been returned or paid off through depreciation rate recovery.

Q. WHAT ARE THE GENERAL RATEMAKING GOALS OF CAPITAL RECOVERY OR DEPRECIATION RATES?

A. Generally, regulatory authorities set depreciation rates on a straight-line basis to recover a capital investment over the useful life of an asset. By straight-line recovery, I mean a recovery of an equal amount in each year of the asset life. Thus, as an example, if an investment of $100 in plant is expected to have a useful life of five years, a depreciation expense of $20.00 per year included in rates would allow recovery of $100 over the five year asset life. This example assumes no salvage value or cost of removal associated with the asset.

Q. WHAT ARE THE CONSEQUENCES OF A LOW DEPRECIATION RATE FOR CAPITAL RECOVERY?

A. If the depreciation rate is set too low then at some point in the asset life depreciation recovery will need to be accelerated to fully recover the asset costs over the asset life. The impact is customers in early years did not pay the full cost of the asset and future customers are required to pay higher rates to make up for the early year shortfall in capital recovery.

Q. WHAT ARE THE CONSEQUENCES OF AN ARTIFICIALLY HIGH DEPRECIATION RATE?

A. When depreciation rates are too high, early year customers end up paying more of the costs than future customers. In this case rates (depreciation) must be reduced to avoid further cost shifting.

Setting depreciation rates and capital recovery streams is a continuous estimating process involving forecasts of numerous variables, thus perfection is not possible or likely in the rate setting process. But, when over or under-recoveries are found to exist, the goal should be to correct such capital recovery errors to avoid compounding the rate inequities.

Q. HOW DOES A REGULATORY AUTHORITY DETERMINE WHETHER DEPRECIATION RECOVERY AND ASSOCIATED RESERVES ARE ADEQUATE?

A. As noted above, depreciation cost recovery estimates are based on forecasts of numerous variables. Recognizing forecasts are inherently imperfect, regulatory authorities typically require periodic depreciation study updates (usually four to five years) to assure useful life and/or net salvage estimates remain reasonable and reliable for setting rates.

To determine the adequacy of the depreciation reserve or accrual, a theoretical reserve is often calculated in new depreciation studies. A theoretical reserve is the accumulated provision for depreciation at a point in time, assuming the most current depreciation parameters and estimates had been historically applied in setting rates. The theoretical reserve is compared to the actual reserve to determine whether there has been an over/under recovery of depreciation. In this case, applying all of Progress Energy's assumptions in the Company's depreciation study results in a theoretical reserve that indicates the actual depreciation reserve is over-funded by more than $645,805,342, which can be found at page 2-79 of the Company's depreciation study.

Q. HAS THIS COMMISSION ADDRESSED EXCESS RESERVE ISSUES IN PAST CASES?

A. Yes. There are a number of other instances in which this Commission has addressed the depreciation reserve issue and these cases are discussed in the direct testimony of Mr. Pous.

Thus, the issue of correcting over/under recoveries of capital amortization is not a new issue. This Commission has recognized the need for such corrections in numerous cases to assure rates are just and reasonable.

SECTION III: <u>PROGRESS ENERGY'S CURRENT EXCESS DEPRECIATION RESERVE</u>

Q. IS THERE AN EXCESS RESERVE IN THIS CASE?

A. Yes. Based on the Company's most current depreciation study, the Company has been collecting excessive amounts of depreciation. This means that current customers have been overpaying for electric service and future customers will be subsidized if this problem is not addressed.

Q. WHAT IS THE AMOUNT OF THE EXCESS DEPRECIATION RESERVE?

A. Based on the Company's depreciation study and information provided by witness Pous, the amount of excess depreciation charged to customers is $645,805,342. I have included in my Exhibit No. __ (DJL-2) a breakdown of the excess depreciation reserve by operating function.

As is demonstrated in Exhibit No. (DJL-2), based on the Company's current best estimates, customers of Progress have been charged $645,805,342 in excess depreciation. In other words, past customers have been overcharged for depreciation and future customers will be charged less than full cost of service if this problem of past excess depreciation charges is not addressed.

Q. WHAT DOES THE DEPRECIATION RESERVE SURPLUS INDICATE REGARDING PAST DEPRECIATION RATES AND CHARGES TO CUSTOMERS?

A. These reserve surpluses mean that Progress Energy should have been recording and charging substantially lower depreciation expenses in prior years to recover the costs of using assets serving customers. But instead, customers have been charged excessive costs and the depreciation reserve is overstated. Again, Progress charged the legal rate, but the depreciation rates in cost of service were over-estimated. Only by reversing these excess charges by amortizing the excess reserve over the next few years will customers that paid the excessive rates be compensated, and the depreciation reserve corrected. Any further delay in correcting this excess reserve or employing a longer amortization period will inevitably result in continued intergenerational inequities.

SECTION IV: <u>EXCESS DEPRECIATION RESERVE PROPOSED SOLUTION</u>

Q. HOW SHOULD THE EXCESS RESERVE PROBLEM BE ADDRESSED IN THIS CASE?

A. Mr. Pous has proposed that the excess reserve be flowed back or corrected over a four year period. Quite simply, $161,451,336 ($645,805,342/4) of excess depreciation reserve is being employed to fund a like amount of currently requested depreciation and amortization expense annually in this case. After four years the reserve should be approximately at levels expected by current depreciation parameters and forecasts.

Mr. Pous' four year amortization proposal addresses the excess depreciation reserve problem over a period of time which is consistent with the expected time period between rate increase requests. Waiting for future studies will only result in estimating larger future excess depreciation reserves and an even larger problem to resolve.

Further, Mr. Pous' analysis indicates that the excess depreciation reserve is actually on the order of $858 million. Thus, accepting Mr. Pous' recommendations indicates that this excess reserve problem is likely to continue. Only by addressing the approximate $646 million excess reserve acknowledged by the Company in this case will this problem be minimized.

Q. WILL MR. POUS' PROPOSAL TO CREDIT DEPRECIATION EXPENSE CREATE OR HAVE ANY PRICING IMPLICATIONS?

A. No. As I understand Mr. Pous' proposal, the depreciation excess reserves will be credited based on functional category. In other words, production excess reserves go to credit production depreciation expense, transmission to transmission expense and so on as to other functions. Thus, no pricing or allocation problems are created by Mr. Pous' proposal – the excess reserves are returned or credited to customers by function in the same fashion as the excess depreciation was paid. Thus, Mr. Pous' proposal is both fair and equitable.

Q. IN YOUR OPINOIN IS THE CORRECTION OF THE EXCESS DEPRECIATION RESERVE CONSISTENT WITH THIS COMMISSION'S RULES AND POLICIES?

A. Yes. The correction of the excess reserve in this case adjusts the plant balances and reserves by function. That is there are no reserve transfers between functions. It is my understanding that the Commission's policy allows reserve transfers within the same function, but not across functions.[1] Thus, the transfer of depreciation reserves to cover costs unrelated to depreciation would not be allowable – but correcting depreciation recovery by adjusting the reserve is allowable under this Commission's policies.

Q. IN YOUR OPINION IS THE CORRECTION OF THE EXCESS DEPRECIATION RESERVE CONSISTENT WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. In my opinion the correction of the excess depreciation reserve is consistent with GAAP. First, the goal of the excess reserve adjustment is to assure the recovery of capital investment is equalized over the useful life of the assets. Thus, the cost to customers is allocated as equitably as possible over the period for which service is obtained from the asset. The correction for the excess reserve corrects the amount of annual recovery to assure proper recovery over the expected useful life. It is an issue of proper allocation of costs and does not diminish or impair the asset value. Full costs will be recovered by the Company – the issue is how much should be recovered annually over the expected remaining life of the assets.

Q. WHAT IS YOUR UNDERSTANDING OF HOW MR. POUS' PROPOSED ADJUSTMENT TO CORRECT THE EXCESS DEPRECIATION RESERVE WILL BE TREATED IN COST OF SERVICE?

[1] FPSC Order No. PSC-94-1199-FOF-EI, September 30, 1994.

A. Mr. Pous' overall findings indicate an excess depreciation reserve of at least $646 million. This level of excess reserve is consistent with the Company's own study. Amortizing this amount over a four year period results in a $161,451,336 annual adjustment (reduction) to depreciation expense. It is my understanding that a cost of service adjustment will reduce depreciation expense in cost of service by the $161,451,336 recommendation and increase rate base by one half of the annual expense adjustment or $80,725,668.

Q. WHAT IS THE CASH FLOW IMPACT TO THE COMPANY OF CORRECTING THE EXCESS DEPRECIATION RESERVE?

A. The cash flow impact is a $161,451,336 reduction in depreciation expense offset by a $12,147,032 increase in return and taxes associated with the increase in rate base. I have included this calculation in my Exhibit No. ___ (DJL-3). Thus, the net impact to the Company's pre-tax cash flow is a net reduction of about $149,304,304.

Q. HOW WILL MR. POUS' PROPOSAL AMORTIZE THE $646 MILLION EXCESS DEPRECIATION RESERVE OVER FOUR YEARS IMPACT PROGRESS?

A. Employing the four year amortization, annual depreciation expenses will be reduced by about $161 million per year. This adjustment will reduce cost of service dollar for dollar that is $161 million. Given that depreciation is not a cash expense, there is no forgone cash recovery by Progress. Instead, the flow of cash to Progress will be reduced. Instead, the rate of recovery of depreciation is adjusted so as to correct the identified excess reserve deficiency. Because recovery of capital is changed by the depreciation adjustment, after four years the level of invested capital will be $646 million higher than it would be absent this adjustment. Again, Progress is not being denied recovery of any cash expense, rather the rate of amortizing invested capital is changed to correct for past accelerated capital recoveries.

Q. WILL MR. POUS' ADJUSTMENT TO CORRECT THE EXCESS DEPRECIATION RESERVE IMPACT THE COMPANY'S CASH FLOW?

A. Yes. By reducing revenue requirements by about $161 million per year, the direct result for a non-cash expense (depreciation), the cash flow paid by customers to the Company will be reduced by this $161 million amount. The cash flow to the Company consists of net income (revenues less expenses) plus depreciation, plus deferred income taxes.

Various measures of cash flow from operations are employed as measures of a firm's financial metrics. One simple measure as described above can be calculated off the Company's rate filing schedule is shown in my Exhibit No. __ (DJL-4).

Thus, under the Company's rate filing assumptions, Progress will have (if the full rate increase is granted) $1,133,646 of cash before income taxes. This amount reflects $574,577 of return to pay interest on debt, preferred stock, and income or return for equity shareholders. The $357,871 is the depreciation and amortization request of the Company, which, if granted, represents the return of capital investment. Lastly, the $201,198 of income taxes represents federal and state current and deferred taxes. Deferred taxes are taxes not currently payable to the taxing authority and are funds available (cash flow) for other business purposes.

Generally, the impact of Mr. Pous' depreciation correction to the excess reserve is to reduce the claimed non-cash depreciation expense of $357,871 by about $161 million before adjustment to Florida retail. The impact of this adjustment is to reduce cash flow by about *$161 million*. In other words, rather than a cash flow of $1,133,646 (shown in Schedule (DJL-4) the annual Company cash flow will be about $976,646 ($1,133,646-$161,000).

Q. WILL MR. POUS' CORRECTION OF EXCESS DEPRECIATION IMPACT THE EARNINGS OF THE COMPANY?

A. No. The return authorized by this Commission will not be impacted by correcting the excess depreciation reserve.

Q. WILL THERE BE AN IMPACT ON EXPENSES FOR CALCULATING INCOME TAXES AS A RESULT OF MR. POUS' CORRECTION TO THE ACCUMULATED DEPRECIATION RESERVE?

A. No. Whatever depreciation expense is allowed by the Commission will still be used *in the tax calculation*. Under Mr. Pous' recommendation, about $161 million of the annual depreciation expense is funded not from increasing customer rates, but instead by reducing the excess depreciation reserve (which was paid by customers in past years).

SECTION V <u>IMPACTS ON FINANCIAL INTEGRITY</u>

Q. IN YOUR OPINION, WILL CORRECTING THE EXCESS RESERVE EMPLOYING A FOUR YEAR AMORTIZATION HARM THE COMPANY'S FINANCIAL INTEGRITY?

A. Correcting the excess depreciation reserve will not harm the Company's financial integrity, although there will be an impact on cash flow financial metrics. It is important to note that under Mr. Pous' proposal cash will decrease by $149 million per anum (see Schedule DJL-3), but at the end of four years rate base will be higher in the amount of $646 million. Thus, Mr. Pous' correction decreases the accumulated provision for depreciation (a rate base reduction) and corrects the depreciation reserve to appropriate or theoretically correct levels. Over the term (4 years), the Company remains whole. Only the recovery period of capital investment changes – no adjustment or reduction is made to the Company's investment.

Q. WHAT FINANCIAL RATIOS AND METRICS ARE IMPORTANT IN EVALUATING A COMPANY'S FINANCIAL INTEGRITY?

A. There is no one key financial metric or group of financial ratios that if attained will result in achieving a particular bond rating level. But, the ratios are helpful in evaluating a company's financial integrity as these financial ratios are helpful in broadly defining a particular company's position relative to a bond rating category. Again, these financial ratios are not used by rating agencies as a prerequisite for achieving or maintaining a specific debt rating.

Key financial metrics and ratios include cash flow-to-debt ratios, a short-term measure of leverage risk, interest coverage ratios measuring earnings coverage of fixed cost interest, and debt to total capital ratio – another measure of leverage. For electric utilities the financial ratio medians by bond rating category are show in my Exhibit No. ___ (DJL-5).

Q. HAVE YOU CALCULATED THE COMPANY'S FINANCIAL METRICS ASSUMING MR. POUS' $646 MILLION EXCESS RESERVE ADJUSTMENT IS IMPLEMENTED IN THIS PROCEEDING?

A. Yes. Included in Exhibit No.(DJL-5) are the results of the excess reserve correction on the financials of the Company. First, this analysis evaluates the impact of only the excess reserve adjustment so that the Commission can evaluate the impact of correcting the excess reserve on the Company. As is discussed below, correcting the excess reserve has a small impact on the Company's cash flow financials. Second, only cash flow is affected by this adjustment. Financial ratios such as "debt ratio" are unaffected by the correction of the excess reserve.

As is demonstrated by the results shown in Exhibit No. (DJL-5), the Company's cash flow ratios decline slightly, but remain well above industry averages. Progress maintains financial integrity after correcting for the excess depreciation.

Q. WHAT DO YOU CONCLUDE REGARDING THE IMPACT OF CORRECTING THE EXCESS DEPRECIATION RESERVE ON THE COMPANY'S FINANCIAL METRICS?

A. Correcting the excess reserve is warranted in that the impact on customers of this correction far outweighs the slight impact on the Company's cash flow financial measures.

Q. IN YOUR CASH FLOW ANALYSIS, HAVE YOU TAKEN INTO CONSIDERATION OTHER CASH FLOW IMPACTS TO PROGRESS?

A. I have included the impact of a 7.50% overall cost of capital, but no other adjustments to cost of service which may impact cash flow. There will be a number of witnesses in this case that make additional adjustment proposals that will impact cash flow. For example, alternative return, depreciation and income tax recommendations will come before the Commission in this case. My analysis focuses solely on the excess depreciation reserve impact and demonstrates that the cash flow reduction allows Progress to maintain solid financial metrics.

Q. BASED ON YOUR ANALYSIS OF THE EXCESS DEPRECIATION RESERVE AND THE CORRECTION PROPOSED BY MR. POUS, WHAT ARE YOUR CONCLUSIONS IN THIS CASE?

A. The excess depreciation reserve, which currently exceeds $646 million of excess depreciation costs collected from customers, should be corrected in this case as recommended by witness Pous. First, if not corrected the situation, in terms of cost shifting, is likely to become worse, not better.

Correcting the excess depreciation reserve does not cut one dollar of cash expense from Progress – correction of the excess depreciation reserve addresses timing of recovery. Customers have paid excess depreciation in past years accelerating the Company's capital recovery. Correcting the excess reserve assures customers pay the true cost of service: no more, no less. Progress will still recover its capital investment, but not on an accelerated basis.

Q. ARE THERE ADDITIONAL REASONS WHY THE COMMISSION SHOULD CORRECT THE EXCESS DEPRECIATION RESERVE?

A. Yes. The Company has requested a substantial increase approaching $500 million annual increase in this case. The economic times and conditions faced by the Company and consumers are well documented and slow recovery is expected. The correction of the excess reserve is an opportunity for this Commission to correct the excess reserve and reduce the rate increase by about $149 million without harming Progress. Such rate reduction does not disallow cash expenditures, but instead corrects the rate of asset recovery. For all of these reasons the Commission should correct the excess reserve at this time as proposed by OPC witness Pous.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. REHWINKEL:

Q. Thank you. Do you have a summary of your prefiled direct testimony prepared?

A. Yes. I have a, a, a brief summary.

Q. And mindful of the Commission's five limit -- five-minute limit, if you can give that to the Commission at this time.

A. I'm fully aware of the Commission's five-minute limit and I'll beat the clock.

Commissioners, it's good to be back in Tallahassee again today. I was here just, what, a couple of weeks ago I guess. And I'm addressing that exciting topic of depreciation reserve, and as well as the financial implications of adjustments thereto.

And the interesting thing is everybody in this case agrees that the depreciation excess reserve is 646 million. The company agrees. Everybody in this room agrees. The issue now is over what period do we amortize that excess reserve? The company proposes somewhat of 20 years. You heard Mr. Pous, who got on prior to me, indicate it should be amortized over a four-year period. So you've got agreement on how much the reserve, excess reserve is.

Now we have two different proposals of how to give it back to customers. Everybody in the room agrees it should go back to customers.

Well, there's some considerations, and that's what my testimony addresses. Not only ratemaking policy, that is, that the customers' money, they have, as we look at it today in that snapshot picture of where we're at on collecting these depreciation dollars, we're overcollected, and the four-year period is a period between rate cases where we can correct this problem.

Well, what other guidance can we look at? Well, in my testimony I address the issue, if you look at the economic times and the size of the rate increase, those are considerations that this Commission may want to employ as guidance on how to determine how that reserve goes back to customers or how quickly.

You've got a company asking for a $500 million rate increase. That's a 30 percent base rate increase, at a time when the economic conditions, not only in the country, but in Florida, with your reliance on tourism and so forth, the economic times are tough. And I'm sure you've heard about it from consumers. Every commission I deal with in rate cases gets letters from consumers at these times when there are high rate increases.

This 161 million, that is the 646 excess reserve divided by four is about 161 million credit to depreciation. The bottom line impact on consumers will be about $150 million because we're making a slight adjustment to rate base with this, and that's pointed out in my testimony.

You can lower in a $500 million increase by $150 million without taking one dime of cash out of the company's pocket, that is just correcting the reserve. A reserve, as I started this discussion, everybody agrees is an excess reserve, and we all know the amounts.

Now what other considerations should the Commission make? I believe the Commission should consider the company's financials. We've gone through, we've calculated the impact. It is $150 million less a year in cash flow to the company. They won't have that cash. That is true. They'll be giving it back to consumers. But it will not harm their financials.

I see my yellow light's on, and I said I'd beat the clock.

CHAIRMAN CARTER: You have two minutes.

THE WITNESS: Well, well, anyway, the 150 million will not harm the company's financials. The company will be able to proceed. If you -- I'm sure there's evidence in this record establishing that this company is not in dire financial trouble. It is consumers at this time that are in financial trouble.

Thank you.

CHAIRMAN CARTER: Thank you very kindly.

MR. REHWINKEL: Mr. Chairman, Mr. Lawton is tendered for cross-examination.

CHAIRMAN CARTER: Thank you.

Ms. Bradley.

MS. BRADLEY: No questions.

CHAIRMAN CARTER: Ms. Kaufman.

MS. KAUFMAN: No questions.

CHAIRMAN CARTER: I'm going to get it right this time, Ms. Alexander. Ms. Alexander.

MS. ALEXANDER: No questions. Thank you.

CHAIRMAN CARTER: Mr. Lavia.

MR. LAVIA: No questions.

CHAIRMAN CARTER: Mr. Burnett.

MR. BURNETT: Have a safe flight back to Austin, sir.

THE WITNESS: Does that mean no questions?

MR. BURNETT: Indeed.

CHAIRMAN CARTER: Staff.

MS. KLANCKE: Staff has no questions for this witness.

CHAIRMAN CARTER: Commissioners, any questions? Wow.

Redirect?

MR. REHWINKEL: I can say no redirect.

CHAIRMAN CARTER: Exhibits? 173 through 177?

MR. REHWINKEL: Yes, sir. The Citizens move those exhibits.

CHAIRMAN CARTER: Are there any objections?

Without objection, show it done.

(Exhibits 173 through 177 admitted into the record.)

Okay. Have a safe flight back to Austin, and thank you so kindly.

THE WITNESS: Can I have another five minutes, Commissioner?

(Laughter.)

Thank you, Commissioners. I appreciate it.

MR. REHWINKEL: And may he be excused?

CHAIRMAN CARTER: And you may be excused. Thank you so kindly.

I think, Commissioners, where we are now, we're going to go through a series of witnesses that have been stipulated. Let's get ourselves together here.

First of all, I think, Mr. Rehwinkel, would you get us together on Witness Dismukes? I think you're recognized. And we'll deal with the testimony, then we'll, direct us to the exhibits.

MR. REHWINKEL: Yes, Mr. Chairman. The Citizens have prefiled the direct testimony of Kimberly H. Dismukes, and we would ask at this time that her prefiled direct testimony be admitted into the record as though read by stipulation of all the parties.

CHAIRMAN CARTER: Okay. Based upon the representations of the parties, that is correct; right? This witness has been stipulated? The prefiled testimony of the witness will be inserted into the record as though read.

Exhibits?

MR. REHWINKEL: Yes. And --

CHAIRMAN CARTER: Tell us what page you're on on staff's Comprehensive Exhibit List.

MR. REHWINKEL: I'm looking on --

MS. FLEMING: Page 37.

CHAIRMAN CARTER: 37? Thank you, staff.

MR. REHWINKEL: Yes. Ms. Dismukes filed exhibits that are identified for hearing at, from Number 145 through 152, and we would ask that those be admitted per stipulation of the parties.

CHAIRMAN CARTER: Are there any objections? Without objection, show it done.

(Exhibits 145 through 152 marked for

identification and admitted into the record.)

I think that takes care of you, Mr. Rehwinkel.

MR. REHWINKEL: Thank you. And I think there was a --

CHAIRMAN CARTER: Yes, sir.

MR. REHWINKEL: The staff had a -- I don't know if there was anything else that was to be --

CHAIRMAN CARTER: Staff? By the way, staff, did we do 286 on Mr. Pous? I think we did.

MS. FLEMING: Yes, we did.

CHAIRMAN CARTER: So we're covered on that. Okay.

Staff, did you have any on Witness Dismukes?

MS. FLEMING: No. I think Mr. Rehwinkel's question was with respect to maybe Mr. Lawton's?

CHAIRMAN CARTER: Mr. Lawton's?

MS. FLEMING: Is that correct?

MR. REHWINKEL: I thought there was a desire to have a portion of her deposition admitted as an exhibit.

MS. FLEMING: Okay. And I believe it is --

MR. REHWINKEL: But that -- I don't know what the agreement with the other parties was.

MS. FLEMING: Yes. I believe it is my understanding -- that was Erik's witness; correct?

Okay.

CHAIRMAN CARTER: What's the plan?

MS. FLEMING: I will make the executive decision. We handed out a portion of a deposition transcript for Ms. Dismukes, and I believe all the parties have stipulated to that, so we would ask that that be marked as hearing Exhibit 287.

CHAIRMAN CARTER: 287. Is that, is that the agreement of the parties, 287? Okay. All right. And hearing no -- and we'll just enter it in without objection. Show it done.

(Exhibit 287 marked for identification and admitted into the record.)

Staff, you can give us a short title, please.

MS. FLEMING: Excerpt of Depo Transcript for Dismukes.

CHAIRMAN CARTER: Outstanding.

Okay. Without objection, show it done.

TESTIMONY

OF
KIMBERLY H. DISMUKES

On Behalf of the
Office of the Public Counsel

Before the
Florida Public Service Commission

Docket No. 090079-EI

Q. **WHAT IS YOUR NAME AND ADDRESS?**

A. Kimberly H. Dismukes, 6455 Overton Street, Baton Rouge, Louisiana 70808.

Q. **BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?**

A. I am a partner in the firm of Acadian Consulting Group, which specializes in the field of public utility regulation. I have been retained by the Office of the Public Counsel (OPC) on behalf of the Citizens of the State of Florida to analyze the transactions between Progress Energy Florida, Inc.'s (PEF, Progress Energy, or the Company) and its affiliates, the nonregulated operations of PEF, and the direct assignment of costs used in the jurisdictional separations study.

Q. **DO YOU HAVE A SUMMARY OF YOUR QUALIFICATIONS IN REGULATION?**

A. Yes. Exhibit KHD-1 was prepared for this purpose.

Q. **DO YOU HAVE EXHIBITS IN SUPPORT OF YOUR TESTIMONY?**

A. Yes. Attached to my testimony are Exhibits KHD-2 through KHD-8 which support my testimony and recommendations.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In the first section of my testimony I discuss the importance of examining transactions between PEF and its affiliates. Second, I briefly describe the organizational structure of Progress Energy, Inc., and third I discuss the Company's nonregulated operations. The fourth section contains a discussion of the Company's allocation to its wholesale operations and associated adjustments. Finally, section five contains a discussion of my concern with PEF's non-recurring fiber indemnification against costs associated with certain assets that were sold by an unregulated affiliate.

I. Affiliate Transactions

Q. WHY IS IT IMPORTANT TO CLOSELY EXAMINE AFFILIATE TRANSACTIONS?

A. In a situation involving the provision of services between affiliated companies, the associated transactions and costs are not arms-length dealings. Cost allocation techniques and methods of charging affiliates should be frequently reviewed and analyzed to ensure that the company's regulated operations are not subsidizing the nonregulated operations. Because of the affiliation between PEF and the affiliates that contribute to expenses included on the books of PEF, the arms-length bargaining of a normal competitive environment is not present in their transactions. Although each of the affiliated companies is supposedly separate, relationships between PEF and these affiliates are still close; they all belong to one corporate family.

In the absence of regulation, there is no assurance that affiliate transactions and allocations will not translate into unnecessarily high charges for PEF's customers. Even when the methodologies for cost allocation and pricing have been explicitly stated, close scrutiny of affiliate relationships is still warranted. Regardless of whether or not PEF explicitly establishes a methodology for the allocation and distribution of affiliate costs, there is an incentive to misallocate or shift costs to regulated companies so that the nonregulated companies can reap the benefits.

Q. **DOES THE COMMISSION HAVE ANY GUIDELINES WHICH CONTROL THE PRICING ARRANGEMENTS BETWEEN UTILITIES AND THEIR AFFILIATES?**

A. Yes. The Commission's Rules set forth the criteria to be followed by electric utilities when transacting with affiliates. Rule 25-6.1351, Florida Administrative Code (F.A.C.) details the Commission's policy. It excludes affiliate transactions related to the purchase of fuel and related transportation services that are subject to the Commission's review in cost recovery proceedings. The section of the Commission's Rule that details the pricing between affiliates is as follows:

> (3) Non-Tariffed Affiliate Transactions
>
> (a) The purpose of subsection (3) is to establish requirements for non-tariffed affiliate transactions impacting regulated activities. This subsection does not apply to the allocation of costs for services between a utility and its parent company or between a utility and its regulated utility affiliates or to services received by a utility from an affiliate that exists solely to provide services to members of the utility's corporate family. All affiliate transactions, however, are subject to regulatory review and approval.

The rules state that purchases from the utility by the affiliate must be at the higher of fully allocated cost or market price.

> (b) A utility must charge an affiliate the higher of fully allocated costs or market price for all non-tariffed services and products purchased by the affiliate from the utility. Except, a utility may charge an affiliate less than fully allocated costs or market price if the charge is above incremental cost. If a utility charges less than fully allocated costs or market price, the utility must maintain documentation to support and justify how doing so benefits regulated operations. If a utility charges less than market price, the utility must notify the Division of Economic Regulation in writing within 30 days of the utility initiating, or changing any of the terms or conditions, for the provision of a product or service. In the case of products or services currently being provided, a utility must notify the Division within 30 days of the rule's effective date.

The rule further state that purchases from the affiliate must be at the lower of fully allocated cost or market.

> (c) When a utility purchases services and products from an affiliate and applies the cost to regulated operations, the utility shall apportion to regulated operations the lesser of fully allocated costs or market price. Except, a utility may apportion to regulated operations more than fully allocated costs if the charge is less than or equal to the market price. If a utility apportions to regulated operations more than fully allocated costs, the utility must maintain documentation to support and justify how doing so benefits regulated operations and would be based on prevailing price valuation.

Finally, the rules states that assets transferred from the affiliate to the utility must be transferred at the lower of cost or market and assets transferred from the utility to the affiliate must be transferred at the higher of cost or market.

> (d) When an asset used in regulated operations is transferred from a utility to a nonregulated affiliate, the utility must charge the affiliate the greater of market price or net book value. Except, a utility may charge the affiliate either the market price or net book value if the utility maintains documentation to support and justify that such a transaction benefits regulated operations. When an asset to be used in

> regulated operations is transferred from a nonregulated affiliate to a utility, the utility must record the asset at the lower of market price or net book value. Except, a utility may record the asset at either market price or net book value if the utility maintains documentation to support and justify that such a transaction benefits regulated operations. An independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000. If a utility charges less than market price, the utility must notify the Division of Economic Regulation in writing within 30 days of the transfer.[1]

Q. HAS THE COMMISSION ADDRESSED AFFILIATE TRANSACTIONS IN ITS ORDERS?

A. Yes. The Commission has also expressed its opinion on affiliate transactions and the precedent that should be followed when examining affiliate transactions.

> By their very nature, related party transactions require closer scrutiny. Although a transaction between related parties is not per se unreasonable, it is the utility's burden to prove that its costs are reasonable. Florida Power Corp. v. Cresse, 413 So. 2d 1187, 1191 (Fla. 1982). This burden is even greater when the transaction is between related parties. In GTE Florida, Inc. v. Deason, 642 So. 2d 545 (Fla. 1994) (GTE), the Court established that the standard to use in evaluating affiliate transactions is whether those transactions exceed the going market rate or are otherwise inherently unfair. (FPSC, Order No. PSC-01-1374-PAA-WS; June 27, 2001.)

II. Progress Energy, Inc. Organizational Structure

Q. WOULD YOU PLEASE DESCRIBE THE PROGRESS ENERGY, INC. ORGANIZATION?

A. Yes. Progress Energy, Inc. (PEI), the parent company of PEF, has approximately 68 subsidiaries and affiliates.[2] My Exhibit KHD-2 contains an organizational chart of PEI and its affiliates. Its primary subsidiaries include:

[1] Rule 25-6.1351 F.A.C.
[2] Response to OPC Document Request 80.

1) Progress Energy Florida, Inc. (PEF) the regulated electric company that provides electric service to customers in Florida.

2) Progress Energy Carolinas, Inc. (PEC), the regulated electric company that provides electric service to customers in North Carolina and South Carolina.

3) Progress Energy Service Co., LLC (Service Company) which provides processing, reporting, and management oversight for both PEF and PEC.

> This includes financial services, human resources, corporate communications, legal, regulatory affairs, audit and compliance, real estate and facility services, information technology, and telecommunications.[3]

Q. HOW LARGE ARE PEI'S NONREGULATED BUSINESSES AND HOW HAVE THEY CHANGED OVER TIME?

A. PEI's nonregulated businesses have declined significantly. Nonregulated revenues represented 21.4% of PEI's consolidated revenue in 2005, decreasing to 8.8% in 2006, to 0.2% in 2007, and to 0.1% in 2008. This is indicative of PEI's strategy as outlined in its annual reports to shareholders:

> TRUE TO OUR WORD. At Progress Energy, we have a consistent record of meeting our commitments to our customers, shareholders and employees. Following the merger in 2000, we were faced with significant debt as well as a complex, diversified corporate structure, all of which exposed us to more volatility and risk than desirable. To mitigate these factors, we made a commitment to reduce debt, strengthen our balance sheet in preparation for future growth and focus on our core electric utility business – all of which we have now achieved, including a $1.7 billion reduction in holding company debt. We have divested most of our noncore assets.[4]

[3] Wyckoff Testimony, pp. 5-6.
[4] 2006 Annual Report, p. 6.

> As discussed more fully in Note 3 and "Results of Operations – Discontinued Operations," in accordance with our business strategy to reduce our business risk and to focus on the core operations of the Utilities, many of our nonregulated business operations have been divested or are in the process of being divested.[5]
>
> Over the last several years we have reduced our business risk by exiting the majority of our nonregulated businesses to focus on the core operations of the Utilities. We divested, or announced divestitures, of multiple nonregulated businesses during 2007 and 2006. Consequently, the composition of other continuing segments has been impacted by these divestitures.[6]
>
> Over the last several years we have reduced our business risk by exiting substantially all of our nonregulated businesses to focus on the core operations of the Utilities. Consequently, the composition of other continuing segments has been impacted by these divestitures.[7]

III. Unregulated Services and Products

Q. LET'S TURN TO THE THIRD SECTION OF YOUR TESTIMONY ON THE SUBJECT OF THE COMPANY'S NONREGULATED OPERATIONS. WOULD YOU BRIEFLY EXPLAIN THESE OPERATIONS?

A. Yes. The Company offers numerous products and services that are not regulated or tariffed by the Commission. The revenues and costs for these products and services are recorded below-the-line for ratemaking purposes. Similar to situations with nonregulated affiliates, because these profits are recorded below-the-line for ratemaking purposes, there is an incentive to shift costs to the regulated operations which will yield higher profits for PEF and its parent company PEI. Like the provision of goods and services between regulated and

[5] 2006 Annual Report, p. 22.
[6] 2007 Annual Report, p. 29.
[7] 2008 Annual Report, p. 18

nonregulated affiliates, the Commission should ensure that the regulated operations of PEF do not subsidize the nonregulated operations.

Q. **DOES THE COMMISSION HAVE ANY RULES GOVERNING THE COSTS CHARGED BETWEEN REGULATED AND NONREGULATED OPERATIONS OF ELECTRIC UTILITIES?**

A. No, it does not. However, I believe the Commission can utilize the same principles embodied in its affiliate transactions rules as guidelines for examining the relationship between the Company's regulated and nonregulated operations. That is, it should ensure that the regulated operations do not subsidize the nonregulated operations.

Q. **WOULD YOU DESCRIBE THE NONREGULATED SERVICES AND PRODUCTS THAT ARE OFFERED BY PEF?**

A. Yes. PEF offers over 20 different products and services that are not regulated by the Commission. In response to OPC Interrogatory 7, the Company gave the following description of these services:

- PCS Engineering Design and Construction - Design and Construction.
- Managed Services - On-site, utility-owned power quality and reliability services.
- Turnkey Solutions - Utility designed, installed, and tested customer-owned power quality and reliability solutions.
- Power Quality Services - Includes surge protectors and meter-readers for residential customers.
- Lighting – Lighting.
- Infrared Scanning Services - Includes a full range of services to detect and document potential trouble spots to maintain equipment in top condition.

- High Voltage Services - Includes a full range of substation, and on and offsite maintenance work to keep high voltage equipment running in top condition.
- Distribution Services - Includes a full range of on and off-site maintenance work to keep distribution equipment running in top condition.
- Vegetation Services - Includes a full range of services to keep right-of-way clear.
- Metering Services - Includes a full range of solutions to keep transformers operating and at peak efficiency.
- Transformer Services - Includes a full range of solutions to calibrate metering equipment.
- Material Solutions - Includes a full range of supply solutions to meet your material and key equipment needs.
- Joint Trenching - Includes a full range of collaboration for telecommunication facilities in a common trench.
- General System Planning - Includes transient stability analysis.
- Transmission Design - Includes full engineering, design and permitting services for transmission facilities.
- Substation Design, Construction and Maintenance – Includes siting, construction and installation of substations.
- System Protection & Control, Fiber Optic & Meter Services - Includes a full range of solutions to meet meter/Fiber Optic needs.
- All-Connect - Sales agent for Home Wire.
- Off System Power Marketing - Off system sales.
- Water Heater Repair Services.
- Wireless Transmission Tower Attachments - Includes full range of solutions to administer, coordinate and design wireless attachments.[8]

[8] Response to OPC Interrogatory 7.

Q. WERE YOU ABLE TO FIND ANY ADDITIONAL INFORMATION ABOUT THESE PRODUCTS AND SERVICES?

A. Yes. Some of these services and products were advertised on the Company's website. In particular, the HomeWire service, only available to residential customers, is described in detail. The service covers the repair costs on selected residential electrical wiring components. HomeWire covers the repair of electrical wiring and components; it includes $500 worth of covered repairs each year for $3.95 a month. According to the Company, if a problem arises involving outlets, switches, dimmers, fuses, breakers, inside wiring or building-mounted electric meter housing, the customer just needs to call Progress Energy. The Company will schedule repairs with a licensed electrician. PEF also notes that as an added value, its contractors will offer a 15-percent discount for upgrades and non-covered repairs such as pre-existing conditions. However, the service is not available immediately upon enrollment; the customer must wait 30 days before they are eligible for the repair service. Nevertheless, repairs that are needed prior to the 30-day waiting period can be made utilizing the 15-percent discount on labor.[9] Attached as Exhibit KHD-3 is an advertisement for this service which is posted on the Company's website.

Q. WERE THE SURGE PROTECTION SERVICE, OR POWER QUALITY SERVICES, EXPLAINED ON PEF'S WEBSITE?

A. Yes. As shown on Schedule KHD-4, there are two stages of surge protection as explained by the Company:

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[9] http://www.progress-energy.com/custservice/flares/homewire/index.asp

> **Stage One**
> A meter-base protector is a high-energy surge protection device that is installed directly behind the electric meter at your home. All power coming into your home runs through the meter-base protector, making it the first stage of protection against surges.
>
> Progress Energy's meter-base protector is capable of diverting the largest portion of any surge away from your home, which effectively protects major appliances such as air conditioning compressors, washers, dryers, and refrigerators from damaging surges.
>
> The monthly rental fee for the meter-base protector is just $5.95 (plus tax) with a one-time payment of $44.95 (plus tax) for installation. The installation includes a free outdoor electrical grounding inspection and any necessary repairs.
>
> **Stage Two**
> While the meter-base protector offers protection from powerful surges, a small portion of a surges (sic) can still pass through interior wiring or enter through phone, satellite and cable lines, where it can damage sensitive electronics such as TVs, computers, DVD players, and more. Our second stage of surge protection takes the form of premium plug-in protectors, which protect those sensitive electronics. These plug-in protectors are up to six times stronger than some found in retail stores.
>
> Prices may vary depending on application.

The website also has a video customers can watch to help them understand how surge protection works.[10]

Q. **WERE THERE ANY OTHER SERVICES PROVIDED BY THE NONREGULATED OPERATIONS OF PROGRESS ENERGY THAT WERE EXPLAINED ON THE COMPANY'S WEBSITE?**

A. Yes. The Company's website also described its water heater repair service. I have attached as Exhibit KHD-5, the relevant pages from PEF's website. Under this program for $4.99 a month, the Company will handle the "unexpected expense

[10] http://www.progress-energy.com/custservice/flares/surgeprotect/index.asp

and trouble of repairing" its customers water heaters.

Q. **WHAT ABOUT OUTDOOR LIGHTING, WAS THIS EXPLAINED ON THE WEBSITE?**

A. Yes. PEF offers outdoor lighting to residential customers. According to PEF, "not only will your home look more attractive, but your world will seem a little brighter" if a customer purchases its outdoor lighting products. PEF offers a wide variety of designs. After a customer selects his or her product, PEF will design and install the outdoor lights. The advertisement on the Company's website states: "We take care of repairs and maintenance – even down to changing lamps – all for an easy, convenient lease payment that is added to your monthly electric bill. Now that's a bright, beautiful idea." Attached as Exhibit KHD-6 is the information contained on the Company's website about outdoor lighting. Although still advertised on its website, the Company is no longer pursuing this line of business, as it is not considered a core business.[11]

Q. **HOW LARGE ARE THESE NONREGULATED OPERATIONS?**

A. As shown on Exhibit KHD-7, in 2007 their operations produced $22.5 million in revenue, in 2008 $18.5 million in revenue, in 2009 revenues are projected at $20.9 million, and in 2010 revenues are projected at $16.7 million. These projected revenue amounts appear to be understated as the Company had revenue in several categories for the first two months of 2009, but did not show any revenue in these categories for 2009 and 2010. Annualizing these revenues for use as a proxy for 2009 and 2010 indicates projected revenue for 2009 and 2010 of $21.5 million, and $22.5 million, respectively. In response to OPC's discovery,

[11] Response to OPC Interrogatory 396.

the Company explained that the revenue for these services would continue into 2010.[12]

Within the total nonregulated operations, the HomeWire service generated the most revenue at $8.1 million followed by Power Quality Services (surge protection) at $7.0 million. PCS Engineering Design and Construction appears next in line with revenue of $3.7 million in 2007 and $3.2 million projected for 2009. There was no revenue reflected for this service for 2008 or projected for 2010. However, in response to OPC Interrogatory 396, the Company explained that it was only budgeted for 2009 but would continue into 2010.[13]

Q. HOW DOES PEF CHARGE COSTS TO ITS NONREGULATED OPERATIONS?

A. In response to OPC Interrogatory 7, the Company explained that costs are directly charged to the non-regulated products and services which are recorded to below-the-line accounts.[14] In a supplemental response the Company stated: "The methodology for charges to non-regulated businesses can be either direct or allocated. Direct charges are expensed as incurred on the books of the non-regulated business. The only charges that are allocated are customer service employee payroll costs. The employees' time is tracked via time sheets and payroll costs are allocated on a percentage-to-total basis using the time spent on each nonregulated activity as the numerator and total time worked by the employee as the denominator."

Q. HOW MANY EMPLOYEES OF PROGRESS ENERGY ATTRIBUTE SOME OF THERE TIME TO THE NONREGULATED OPERATIONS?

[12] Response to OPC Interrogatory 396.
[13] Ibid.
[14] Response to OPC Interrogatory 7.

A. There are approximately 47 persons that attribute time to the nonregulated operations of PEF as well as PEC. Of these 47 employees, 15 are sales representatives, eight provide back office support, seven are field coordinators, six provide technical support, and the remainder provide programming, IT, and accounting support.[15]

Q. HOW DOES THE COMPANY ACCOUNT FOR THE REVENUES, EXPENSES, AND INVESTMENT FOR ITS NONREGULATED OPERATIONS?

A. The revenues and expenses associated with its nonregulated operations are recorded below-the-line. Any capital required for the nonregulated operations is booked to Nonutility Property.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S NONREGULATED OPERATIONS AND HOW ITS COSTS ARE ACCOUNTED FOR?

A. Yes. I have several concerns.

Q. WOULD YOU DISCUSS YOUR FIRST CONCERN?

A. Yes. Although OPC requested that the Company provide the amount of expenses (by account) allocated, assigned, or otherwise charged to its nonregulated operations, the Company provided this information for only two accounts 417001 and 4210701, as depicted on Exhibit KHD-7. The Uniform System Of Accounts (USOA) describes account 417 as expenses of nonutility operations. It also explains the purposes of the expense account and related revenue account as follows:

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[15] Ibid.

A. These accounts shall include revenues and expenses applicable to operations which are nonutility in character but nevertheless constitute a distinct operating activity of the enterprise as a whole, such as the operation of an ice department where applicable statutes do not define such operation as a utility, or the operation of a servicing organization for furnishing supervision, management, engineering, and similar services to others.

B. The expenses shall include all elements of costs incurred in such operations, and the accounts shall be maintained so as to permit ready summarization as follows:

Operation.
Maintenance.
Rents.
Depreciation.
Amortization.

Note: Related taxes shall be recorded in account 408.2, Taxes Other Than Income Taxes, Other Income and Deductions, or account 409.2, Income Taxes, Other Income and Deductions, as appropriate.

Account 421, Miscellaneous Nonoperating Income, is to include "all revenue and expense items except taxes properly includible in the income account and not provided for elsewhere. Related taxes shall be recorded in account 408.2, Taxes Other Than Income Taxes, Other Income and Deductions, or account 409.2, Income Taxes, Other Income and Deductions, as appropriate."[16]

No detail was provided regarding any type of breakdown of the types of expense charged to the nonregulated operations. Therefore, it is difficult to examine or evaluate the reasonableness of the expenses recorded below-the-line.

Q. WHAT IS YOUR SECOND CONCERN?

A. My second concern relates to the type of costs that have been assigned to the nonregulated operations. According to the Company's response to OPC's

[16] FERC Uniform System of Accounts.

Interrogatory 7, only the direct costs and allocated customer service employee payroll costs are charged to these nonregulated operations and thus removed from PEF's expenses recorded above-the-line. The Company's supplemental response to OPC's Interrogatory asking: "For each non-regulated service or product identified in (a), please explain how costs are allocated or charged to the non-regulated operations of Progress Energy Florida."

> The methodology for charges to non-regulated businesses can be either direct or allocated. Direct charges are expensed as incurred on the books of the non-regulated business. The only charges that are allocated are customer service employee payroll costs. The employees' time is tracked via time sheets and payroll costs are allocated on a percentage-to-total basis using the time spent on each nonregulated activity as the numerator and total time worked by the employee as the denominator.[17]

The Company's response indicates that there are common overhead costs that have not been assigned to these nonregulated operations. The Company did indicate in response to OPC Interrogatory 296 that some governance costs from Progress Energy Service Company were allocated to the nonregulated operations.[18]

These overhead costs would include but not be limited to all administrative and general expenses consisting of: Administrative and General Salaries, Office Supplies and Expense, Outside Services, Property Insurance, Injuries and Damages, Employee Pensions and Benefits, Franchise Requirements, Regulatory Commission Expenses, General Advertising Expenses, Miscellaneous General Expenses, and Rents.

[17] Supplemental Response to OPC Interrogatory 7.
[18] Response to OPC Interrogatory 296.

Q. IS THERE ANY EXPLANATION OF HOW THESE COSTS ARE ASSIGNED TO THE COMPANY'S NONREGULATED OPERATIONS IN THE COMPANY'S COST ALLOCATION MANUAL?

A. No. There is no discussion on this in the Company's cost allocation manual.

Q. WHAT IS YOUR NEXT CONCERN?

A. There are substantial benefits to PEF's nonregulated operations of being associated with the regulated company. These benefits include the use of Progress Energy's name, logo, reputation, goodwill, and corporate image; being associated with a large, financially strong, well-entrenched electric company; use of Progress Energy's personnel; and use of Progress Energy's facilities. All of these benefits were developed as a result of the regulated operations. However, the nonregulated operations obtain these significant intangible benefits of being associated with the regulated utility operations at no cost.

Q. HAVE YOU EXAMINED ANY DATA WHICH INDICATES THAT PROGRESS ENERGY'S NONREGULATED OPERATIONS ARE UNDER ALLOCATED COSTS?

A. Yes. I examined the return on net investment earned by the Company's nonregulated operations as a gauge of whether or not the costs have been properly assigned or allocated. To the extent the return on investments appears abnormal, the Commission should be concerned about the attribution of costs between the Company's regulated and nonregulated operations.

Q. WHAT RETURN ON INVESTMENT DID THE COMPANY'S NONREGULATED OPERATIONS EARN?

A. As shown on Exhibit KHD-7, based upon the data supplied by the Company for revenues, expenses, and net investment of the nonregulated operations, this segment of PEF earned a return of 109% in 2007, 131% in 2008, 176% projected for 2009 and 92% projected for 2010. However, as discussed earlier, the two projected years exclude revenue that has historically been generated by the nonregulated operations. Imputing the revenues that are understated in 2009 and 2010 produces a return on net investment of 188% in 2009 and 212% in 2010. Such high returns on investment are abnormal and strongly suggest that the costs attributed to the nonregulated operations are seriously understated.

Q. HOW CAN THE COMMISSION ENSURE THAT THE REGULATED OPERATIONS DO NOT SUBSIDIZE THE NONREGULATED OPERATIONS?

A. There are at least three options the Commission should consider. First, it could require the Company to properly allocate all overhead costs to the nonregulated operations. In addition to allocating costs to the nonregulated affiliate, the Commission could assess a royalty fee for the intangible benefits the nonregulated operations receive from their association with the regulated electric company.

Second, the Commission could determine a reasonable rate of return that should be achieved by the nonregulated operations. Anything in excess of this return, should be returned to ratepayers.

Third, the Commission could move the revenues, expenses, and investment above the line for purposes of establishing rates in this proceeding.

Q. WHAT IS YOUR RECOMMENDATION CONSIDERING THE OPTIONS YOU HAVE CITED?

A. I recommend that the Commission chose the third option that I have offered and essentially treat these revenues, expenses and investment above-the-line for rate setting purposes. The Company has failed to demonstrate that costs have been properly allocated to these nonregulated operations.

To implement this recommendation, I developed an adjustment to net operating income by using the return on rate base recommended by Dr. Woolridge of 7.53%. The difference between the allowed net operating income and the achieved net operating income, grossed up for income taxes, is the amount of revenue that should be moved above-the-line for rate setting purposes. As shown on Exhibit KHD-7, I recommend an adjustment to net operating income of $8.6 million.

In addition, I recommend that the Commission order the Company to conduct a thorough examination of these operations and develop cost allocation procedures that can be used to allocate costs to these nonregulated operations. These procedures can then be examined and audited as part of the Company's next rate proceeding. However, until the Company properly accounts for these costs, the Commission should treat all amounts above the line for ratemaking purposes.

IV. Wholesale Direct Assignment

Q. WOULD YOU PLEASE ADDRESS THE COMPANY'S ALLOCATIONS TO ITS WHOLESALE OPERATIONS?

A. As part of its jurisdictional allocation study, the Company assigned certain cost directly to its wholesale operations. This is different from an allocation which is often used to allocate costs to the utility's wholesale operations. While the Company also allocates costs to its wholesale operations, I am addressing only the direct assignment of certain costs.

Q. WHAT IS A JURISDICTIONAL ALLOCATION OR SEPARATIONS STUDY?

A. A jurisdictional allocation study allocates joint and common costs between the Company's retail operations (regulated by the Commission) and its wholesale operations (regulated by the Federal Energy Regulatory Commission). A jurisdictional allocation study allocates all components of the Company's regulated expenses and rate base between these two jurisdictions.

Q. WITH RESPECT TO THE DIRECT ASSIGNMENT OF COSTS TO THE WHOLESALE JURISDICTION, DID THE COMPANY EXPLAIN HOW THIS WAS ACCOMPLISHED?

A. No, it did not. In Mr. Slusser's testimony, he provides the following explanation of how these costs were treated:

> In accordance with Commission Order No. PSC-99-1741-PPA-EI in Docket No. 990771-EI, specific amounts of plant and expense related to a sale to the City of Tallahassee have been assigned to the wholesale business. These costs, of course, have not been included in the balance of production costs assigned or allocated to any other customers.

Q. DID YOU INQUIRE THROUGH DISCOVERY HOW THESE COSTS WERE DEVELOPED?

A. Yes. In OPC Interrogatory 338, the Company was asked to explain the methodology for determining what plant is included in the plant in service Account 320-325 Nuclear- D/A wholesale. The Company responded:

> The amounts in Accounts 320-325 Nuclear D/A Wholesale relate to PEF's acquisition of the City of Tallahassee's interest its Crystal River Unit 3 plant. Please see the response to Citizens' 2nd Set of Interrogatories, Question #105, for FPSC Order No. PSC-99-174[1]-PAA-EI approving the regulatory treatment of the Tallahassee buy-back.[19]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE METHODOLOGY USED BY THE COMPANY TO ASSIGN COSTS TO THE CITY OF TALLAHASSEE'S INTEREST IN CRYSTAL RIVER UNIT 3 PLANT?

A. Yes. When assigning costs to this category, the Company did not assign any general plant to this group, and it only assigned a very small share of its administrative and general expenses.

Q. DID THE COMMISSION'S ORDER NO. PSC-99-1741-PAA-EI APPROVING THE REGULATORY TREATMENT OF THE TALLAHASSEE BUY-BACK CONTAIN ANY GUIDANCE ON THE ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSES?

A. No, it did not.

Q. WHY SHOULD THESE COSTS BE ASSIGNED TO THIS WHOLESALE DIRECT ASSIGNMENT CATEGORY?

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[19] Response to OPC Interrogatory 338.

A. General plant and administrative and general expenses are common costs which essentially support the Company's entire operations. They are not dedicated to specific groups of customers. These costs should be distributed to all customers, including those for which the Company's uses a direct assignment methodology.

A. DID THE COMPANY ASSIGN ANY OF THESE COSTS TO THE DIRECT WHOLESALE CATEGORY?

A. It did not assign any general plant, but it assigned a very small portion of its administrative and general expenses.

Q. HOW DO YOU RECOMMEND THAT GENERAL PLANT AND ADMINISTRATIVE AND GENERAL PLANT BE ALLOCATED TO THE DIRECT ASSIGNMENT GROUP?

A. I recommend that the Commission allocate general plant to the Company's Directly Assigned Wholesale operations using its percentage of total production, transmission and distribution plant to the total company production, transmission, and distribution plant. As shown on Exhibit KHD-7, this would reduce general plant allocated to the Company's retail operations by $2.3 million. Using the same methodology for allocating accumulated depreciation, net plant for the retail operations should be reduced by $1.8 million.

Q. HOW SHOULD ADMINISTRATIVE AND GENERAL EXPENSES BE ALLOCATED TO THE DIRECT ASSIGNMENT GROUP?

A. I recommend that administrative and general expenses be allocated using this group's percentage of production, transmission, and distribution expenses to the total company production, transmission, and distribution expenses. This allocation assigns the administrative and general expenses in proportion to the costs which are the substance of the Company's operations.

Q. UNDER YOUR RECOMMENDED METHODOLOGY, WHAT ADJUSTMENT IS NEEDED TO THE RETAIL JURISDICTION'S EXPENSES?

A. As shown on Exhibit KHD-8, the Commission should reduce retail test year administrative and general expenses by $6.3 million. This amount is net of the $2.3 million the Company assigned to the direct wholesale group.

Q. ARE YOU RECOMMENDING ANY OTHER ADJUSTMENTS IN THIS AREA?

A. Yes. I am recommending two related adjustments. The first is for the property taxes associated with the general plant. This adjustment reduces test year expenses by $.017 million. Likewise, depreciation expense should be reduced by $.069 million.

V. Non-Recurring Fiber Indemnification

Q. WOULD YOU PLEASE DISCUSS THE SALE OF PROGRESS TELECOMMUNICATIONS, LLC IN 2006 AND ITS POSSIBLE IMPLICATIONS ON THE COMPANY AND ITS CUSTOMERS?

A. Yes. On March 20, 2006 Progress sold its interest in Progress Telecommunications, LLC to Level 3 Communications. As a result of the sale Progress received proceeds of $69 million and about 20 million shares of Level 3 Communications, Inc. common stock. Progress recorded an after-tax gain of $28 million as a result of the sale. In connection with this sale PEF provided an indemnification against costs associated with certain assets performances to Level 3 Communications.[20]

Q. DID THE COMPANY RESPOND TO ANY DISCOVERY ON THIS MATTER?

A. Yes. In response to OPC Interrogatory 328, when asked to explain the purpose of the nonrecurring fiber indemnification and to describe the benefits to customers, the Company explained:

> PEF incorporates its general objections and specific objections to OPC interrogatory 328 and, subject to these objections and without waiving same, PEF answers as follows:
>
> The purpose of the non recurring fiber indemnification in 2006 between Progress Telecommunications LLC (PTLLC) and Progress Energy Florida was to facilitate the sale of Progress Telecom LLC (PTLLC) by accepting the responsibility for 100% of the capital replacement cost of approximately 400 miles of fiber in Florida that was experiencing problems with fiber casings and fiber degradation (referred to as the "Fiber 400 Project"). The indemnification of the fiber was part of negotiations related to the sale of PTLLC to Level 3. As a result of the indemnification, PEF recorded a liability (as required by accounting rules), based on the estimated cost to repair the defective fiber, and a receivable from Progress Telecommunications Corporation (PTC), the parent of PTLLC.
>
> The impact of the indemnification to customers is neutral. While PEF recorded the liability, because the costs to replace the fiber would be incurred by PEF, these liabilities were reimbursed by PTC, so ultimately there would be no cost to PEF, therefore, there would be no impact to Progress Energy Florida customers.[21]

Q. IS THE COMPANY'S RESPONSE SUFFICIENT IN ENSURING THAT CUSTOMERS BEAR NO COST ASSOCIATED WITH THIS INDEMNIFICATION?

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[20] Progress Energy, Inc., 10-K, p. 148.
[21] Response to OPC Interrogatory 328.

A. No. The Company's response suggests that there "would" be no cost to ratepayers as a result of the indemnification and that "ultimately" there would be no cost incurred by PEF. However, given that this has not been resolved and the indemnification could exist for many more years, there may be a cost to PEF and its customers. At this point it is not clear how the costs associated with the indemnification liabilities have been recorded on the Company's books and whether or not they are reflected in the test year.

In addition, the Commission should question why PEF is indemnifying assets which have been sold and for which another affiliate, Progress Telecommunications Corporation, will reimburse PEF. Clearly, there is a cost and value associated with the indemnification, and the Commission should thoroughly examine if the costs are being borne by ratepayers without any benefit.

Q. **WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS?**

A. Yes. I recommend that the Commission increase test year net operating income by $8.6 million to recognize the fact that the Company has not properly allocated common costs to its nonregulated operations.

Second, regarding the Company's direct assignment to its wholesale operations, I recommend that the Commission reduce test year administrative and general expenses by $6.3 million, property taxes by $.017 million, and depreciation expense by $.069 million. In addition, net plant should be reduced by $1.8 million to correct the Company's failure to allocate any general plant to its directly assigned wholesale operations.

Third, the Commission should investigate the indemnification provided by PEF to assets sold by a nonregulated affiliate. The Commission should ensure that no costs associated with this have been passed on to ratepayers.

Q. **DOES THIS COMPLETE YOUR TESTIMONY PREFILED ON AUGUST 10, 2009?**

A. Yes, it does.

CHAIRMAN CARTER: Mr. Rehwinkel.

MR. REHWINKEL: That is it. My only remaining witness is Dr. Woolridge, who is time certain Tuesday morning.

CHAIRMAN CARTER: Okay.

I think Ms. Alexander, you're recognized.

MS. ALEXANDER: Yes. Thank you, Mr. Chairman. We'd like to move in the prefiled direct testimony of Russell L. Klepper by stipulation of the parties into the record as though read.

CHAIRMAN CARTER: Okay. Based upon the stipulation of the parties, no objection, without objection, the prefiled testimony of the witness will be inserted into the record as though read.

Exhibits?

MS. ALEXANDER: Yes. We'd also like to move into the record Exhibits RLK-1 and RLK-2. Those are on staff's composite exhibit numbered 178 and 179.

CHAIRMAN CARTER: That's found on Page 39. 178 and 179?

MS. ALEXANDER: Correct.

CHAIRMAN CARTER: Are there any objections? Without objection, show it done.

(Exhibits 178 and 179 marked for identification and admitted into the record.)

MS. ALEXANDER: We'd also like to move into the record the deposition transcript of Russell L. Klepper. We need a hearing exhibit number on that. I believe it would be 288.

CHAIRMAN CARTER: That'll be 288. Is there any objection of the parties? Is that by stipulation agreement of the parties?

Mr. Burnett?

MR. BURNETT: May I have one moment, sir?

CHAIRMAN CARTER: Yes, sir. Let's take a moment.

(Pause.)

MR. BURNETT: I'll make a command decision, sir. No objection.

CHAIRMAN CARTER: Okay. So 288 would be --

MS. ALEXANDER: I actually have copies with me. I'll pass them around right now.

CHAIRMAN CARTER: Give me a short title.

MS. ALEXANDER: Deposition Transcript of Witness Klepper.

CHAIRMAN CARTER: Okay. Without objection, show it done.

(Exhibit 288 marked for identification and admitted into the record.)

MS. ALEXANDER: And also we'd like to move in the discovery responses of AFFIRM to staff's interrogatories and production requests. I believe those will be provided to the parties by CD. The staff was kind enough to do that. And I believe we'd ask that that have an exhibit number; I would assume 289.

CHAIRMAN CARTER: 289. Are there any objections on 289? Any objections?

MR. BURNETT: No, sir.

CHAIRMAN CARTER: Okay.

MS. FLEMING: And, Mr. Chairman, if I may.

CHAIRMAN CARTER: Yes, ma'am.

MS. FLEMING: I would just note that we are in the process of making copies of the CDs, and we'll provide those to the parties whenever we get a break or later this afternoon.

CHAIRMAN CARTER: Okay. Without objection, show it done. It's entered into as, 289 is entered into the record.

(Exhibit 289 marked for identification and admitted into the record.)

Ms. Alexander, you are recognized.

MS. ALEXANDER: That's it. Thank you, Your Honor.

CHAIRMAN CARTER: That's it? Thank you so kindly, and that completes it for Witness Klepper.

FBEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

RUSSELL L. KLEPPER

ON BEHALF OF FLORIDA AFFIRM

DOCKET NO. 090079-EI

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

A. My name is Russell L. Klepper. I am a Principal of Energy Services Group, LLC, an energy and utility consulting firm that I helped to found. Our business address is 316 Maxwell Road, Suite 400, Alpharetta, Georgia 30009.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science in Business Administration with a major in Economics and a Master of Business Administration with a major in Finance, both from the University of Florida, and a Master of Professional Accountancy from Georgia State University. I have over thirty-two years of applicable utility experience, the first seven of which were spent in the financial areas of Georgia Power Company. During my last three years of employment by that electric utility, I held the title of Manager of Financial Services. For the past twenty-five years, the preponderance of my time has been spent as an independent consultant on utility finance, rates and regulation, and regulatory transition issues, as well as certain facets of the economics of both regulated utilities and unregulated firms that produce, sell, and distribute energy for consumption by ultimate consumers. I have provided professional services to both investor owned and governmental utilities, to private companies that have significant interests in the energy industry, and to entities such as the World Bank, the United States Energy Association, and the Edison Electric Institute. As a consultant, I have developed and presented two national seminars and numerous in-house seminars that focus on different aspects of utility planning and decision-making. A more detailed Summary of Professional Credentials is attached as an Appendix to this direct testimony (Exhibit RLK-1).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am here on behalf of Florida AFFIRM (the "Association For Fairness In Rate Making" or "AFFIRM"), a coalition of quick serve restaurants that have substantially similar electrical usage characteristics. The Members of AFFIRM are the corporations and the corporations' franchisees that own and operate over 250 business locations served by Progress Energy Florida, Inc. ("PEF" or the "Company") under the following brand names: Waffle House, Wendy's, Arby's, and YUM! Brands, doing business as Pizza Hut, Kentucky Fried Chicken, Taco Bell, Long John Silver's, and A&W.

Q. PLEASE BRIEFLY SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

A. As explained in detail below, the AFFIRM Members are economically disadvantaged in the purchasing of electric service from FP&L because the pricing alternatives currently available to such multi-location customers do not reflect the economies of scale to PEF that result from providing such service and because the load characteristics of the AFFIRM Members are not effectively captured by PEF's currently available rates. Accordingly, this testimony will propose that the Florida Public Service Commission (the "Commission") direct the Company to establish one or more new rates to be available to commercial customers that will (1) more effectively reflect the beneficial cost causation characteristics of the AFFIRM Members and similarly situated PEF customers, and (2) provide a realistic, cost based economic incentive for commercial customers to undertake load shifting and other voluntary measures to control loads and associated costs. In addition, it is recommended in this testimony that PEF be required to develop new rates based on a cost of service methodology based on 12 CP and $1/13^{th}$ AD, rather than the 12 CP and 50% AD allocation sought by the Company for fixed production capacity costs.

Q. HOW ARE THE AFFIRM MEMBERS ECONOMICALLY DISADVANTAGED IN PURCHASING ELECTRIC SERVICE FROM THE COMPANY?

A. There are two distinctly different ways in which the AFFIRM Members are economically disadvantaged in such purchases. First, the electrical usage characteristics of the AFFIRM Members reflect consumption patterns that materially differ from the majority of commercial customers. Most AFFIRM Members (1) open in the morning, and business activity starts in earnest before the stores open; (2) remain open until late in the evening, and some remain open twenty-four hours per day; (3) are open for business every weekend day and every holiday, with the possible exception of Christmas; (4) have a significant percentage of their load in exterior lighting, with the preponderance of such loads occurring during off-peak hours, and (5) have significant around-the-clock refrigeration loads that are not typical for commercial customers except for restaurants. Most AFFIRM Members will peak during the Company's designated peak hours, but because exterior lighting is a significant portion of the loads, almost none of the AFFIRM Members will peak in the specific hours during which the Company will experience its monthly peak loads. Typically, the peaks of the individual stores will occur during the lunch rush or after sunset, during the hours that many utilities will designate as either off-peak hours or "shoulder hours" rather than on-peak hours. Based on the electric usage characteristics set forth in this paragraph, when compared to the majority of commercial customers, the AFFIRM Members cause a disproportionately smaller contribution to the Company's monthly system peaks, and also use a disproportionately greater percentage of total energy consumption during off-peak periods.

Almost all of the individual locations of the AFFIRM Members are served under GSD-1. (The very few exceptions may be generally smaller stores that are located in shopping mall food courts.) The structure of GSD-1 is highly unfavorable, for several reasons, to any commercial customers, including the AFFIRM Members, that have the electrical usage characteristics described in the previous paragraph.

Q. WHY DO YOU CONTEND THAT GSD-1 IS UNFAVORABLE TO THE MEMBERS OF AFFIRM?

A. First, GSD-1 assumes that all customers served under this rate will make approximately the same contribution to the system peak. But as explained above, this assumption is incorrect with respect to the AFFIRM Members, whose monthly peaks typically occur during what most utilities deem to be either off-peak hours or shoulder hours rather than on-peak hours. Second, GSD-1 sets forth a proposed base energy charge for all hours of 2.320 cents per kWh, based upon an assumption that the allocation of energy usage between on-peak and off-peak hours is approximately the same for all commercial customers. But as explained above, this assumption is incorrect with respect to the AFFIRM Members, whose pattern of energy consumption is disproportionately higher during off-peak hours compared to the commercial class as a whole. Third, GSD-1 provides that during the five winter months, the period from 6:00 PM to 10:00 PM will be a peak period. Because of the outdoor lighting loads of most AFFIRM Members, the monthly peaks for these customers will almost always occur during these hours. But data produced by the Commission Staff published in the February 2009 Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act (FEECA), attached hereto as Exhibit RLK-2 and entitled "Typical Florida Daily Electric Load Shapes", shows that the winter peaks during the PM hours are no more than 82% of the corresponding winter peaks during the AM hours. Based on such data, customers that peak during the winter PM hours are unjustifiably penalized.

In summary, GSD-1 is made available as a "one size fits all" rate for commercial customers, but the AFFIRM Members have usage characteristics that make GSD-1 particularly ill-suited. Regrettably, notwithstanding the very poor correlation between the structure of GSD-1 and the usage characteristics of the AFFIRM Members, there is no other rate that provides a better economic result to the individual locations of the AFFIRM Members.

Q. PLEASE EXPLAIN WHY NO RATE OTHER THAN GSD-1 WOULD PROVIDE A BETTER ECONOMIC RESULT TO THE AFFIRM MEMBERS.

A. There are only two rates available from PEF to commercial and industrial customers that do not have their own generating resources and that do not wish to take curtailable or interruptible electric service. These rates are GSD-1 (General Service Demand), as discussed above, and GSDT-1 (General Service Demand – Time of Use).

In its present form, GSDT-1 is a highly ineffective rate. From a technical standpoint, the structure of this rate is deficient because the generally higher customer cost incurred under GSDT-1 weighs against the use of this rate by the vast preponderance of commercial and industrial customers. In turn, the unwillingness of customers to use the higher cost GSDT-1 rate precludes any cost reduction benefits that might otherwise be obtained through the rate incentive inherent within time of use rate. Under the rate structure of GSDT-1, it is nearly impossible for any commercial customer to obtain a better economic outcome by using the GSDT-1 rate instead of the "one size fits all"

GSD-1 rate. This situation exists because when the around the clock base energy charge under GSD-1 is compared to the on-peak and off-peak base energy charges under GSDT-1, the customer can consume no more than 29.4% of its total energy usage during on-peak hours to realize a lower cost. By way of comparison, the number of on-peak hours during a calendar year is about 25% of the total hours, and the total energy provided by PEF during on-peak hours is in the neighborhood of 45% of all energy provided by PEF. To place these percentages into perspective, a typical AFFIRM Member consumes about 32% of its total energy usage during on-peak periods, compared to around 45% for the total system, so the load pattern of the AFFIRM Members is clearly more favorable than the Company's total load because the costs incurred in serving off-peak loads are substantially lower than the corresponding costs incurred in serving on-peak loads.

The inferior nature of PEF's commercial time of use rate (GSDT-1) is difficult to illustrate because PEF does not provide the public reporting of information that would demonstrate the ineffective nature of GSDT-1. Specifically, the information shown on PEF's Sales of Electricity by Rate Schedules, a component of PEF's filing of the 2007 FERC Form No. 1, reports aggregate revenues and the aggregate number of customers served under both GSD-1 and GSDT-1. The failure to report separately the revenues and the number of customers under each of GSD-1 and GSDT-1 serves to disguise the fact that very few customers, if any at all, can obtain a lower average cost per kWh by use of GSDT-1 than by simply using the GSD-1, the "one size fits all" rate.

Q. DO YOU BELIEVE THAT A NEW COMMERCIAL TIME OF USE RATE SHOULD BE DEVELOPED AND IMPLEMENTED, AND IF SO, WHY?

A. Yes, a new commercial time of use rate should be developed and implemented. It should be noted that residential customers are a substantially homogeneous group (PEF seeks to terminate its residential time of use rate because only 38 out of approximately 1,455,000 residential customers use the time of use rate). However, by contrast to residential customers, commercial and industrial customers are a heterogeneous group with wide variations in patterns of energy usage. When placed within the same rate class, some commercial and industrial customers have favorable load patterns and others have unfavorable load patterns. When the only viable rate available has a "one size fits all" structure, the commercial and industrial customers with favorable load patterns are forced to subsidize the commercial and industrial customers in the same class. Simply stated, an array of rates should be made available to commercial and industrial customers such that the revenue burden borne by individual customers is more closely related to the costs caused in serving such customers. The most effective means to accomplish this objective is through properly structured time of use rates where the rates in each time period are aligned as closely as possible to the costs in each such time period.

Unfortunately, the existing time of use rate (GSDT-1) is so badly structured that for most customers, it results in a total cost that exceeds the total cost that would be realized by that same customer under the plain vanilla rate (GSD-1). Accordingly, commercial customers (including the AFFIRM Members) who wish to become more energy efficient by responding to electric price signals are denied the realistic opportunity to do so. For this reason, the Commission should instruct the Company to develop a new commercial time of use rate that would be more effective by providing periodic price signals that would in turn provide an incentive to customers to actively endeavor to control their energy costs.

Q. DOES THE COMPANY SUPPORT THE CONCEPT THAT RATES SHOULD PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A. It appears so. The testimony of PEF Witness Slusser recommends the setting of rates in a manner such that the vast majority of PEF customers would pay rates that are very close to parity, i.e., the rates would cover the costs attributable to the major customer classes without any unreasonable degree of cross subsidization between customer classes. When rates are established based on related costs, as recommended by the Company, then the rates provide appropriate price signals and the objective of economic efficiency is well served.

On behalf of AFFIRM, it is requested that the Commission direct the Company to extend this same theory of ratemaking on a more micro-cosmic basis by allocating costs more precisely among sub-groups in the commercial and industrial class and by creating rates that recover revenues from the commercial and industrial customers based more precisely on the cost causation of the individual customers.

AFFIRM asserts that the rates approved by the Commission in this ratemaking proceeding should be reasonable, cost-based and send the appropriate price signals to customers. Unfortunately, while the GSD-1 rate may be just and reasonable as required by applicable statutes, the indiscriminate application of GSD-1 to a group with widely differing load characteristics does not produce just and reasonable charges to all electric customers within the GSD-1 rate class. As discussed above, because the electric characteristics of the AFFIRM Members are materially different from the assumptions upon which the GSD-1 rate is based, the AFFIRM Members are the most disadvantaged customers within the GSD-1 rate group. Further, the only commercial rates available from PEF to AFFIRM Members are not just and reasonable because they are not based on the cost causation characteristics of the AFFIRM Members nor do they send the appropriate price signals to AFFIRM Members or other similarly situated customers.

Q. ARE YOU ABLE TO CITE ADDITIONAL AUTHORITY PROVIDING FOR THE DEVELOPMENT AND IMPLEMENTATION OF COST BASED TIME OF USE RATES FOR AFFIRM MEMBERS AND SIMILARLY SITUATED CUSTOMERS?

A. Yes, I am. The Energy Policy Act of 2005 was enacted by Congress and became federal law on August 8, 2005. Section 1252 of the Energy Policy Act, "Smart Metering", amended Section 111(d) of the Public Utilities Regulatory Policy Act of 1978 by adding the following:

"(14) TIME BASED METERING AND COMMUNICATIONS. – (A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generation and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology."

By submission of this direct testimony in this proceeding, the Members of AFFIRM hereby request that the Commission direct the Company to develop, within the context of this proceeding, a newly developed commercial time of use rate that will satisfy the above cited objective set forth in the Energy Policy Act of 2005.

Q. WHAT IS THE SECOND WAY IN WHICH THE AFFIRM MEMBERS ARE ECONOMICALLY DISADVANTAGED IN PURCHASING ELECTRIC SERVICE FROM THE COMPANY?

A. The AFFIRM Members are multi-location customers that have aggregate diversified loads that in turn provide economies of scale that are realized by the Company in generation, transmission, and administrative functions. Currently, PEF does not make available any multiple location rates that recognize the economic benefits to the Company of serving such customers.

By way of illustration, each of Wendy's/Arby's Group and YUM! Brands has over one hundred fifty locations served by PEF, with each having an aggregate load of approximately 12,000 kW. But this load of 12,000 kW is the sum of the non-coincident peak loads at each location rather than the coincident peak of all locations operated under the same brand. Given the widespread dispersion of such restaurants within the PEF territory, it is possible that the diversity in peaks is 4%, or 480 kW per month. Based on PEF's proposed demand charge of $5.65 per kW per month, the recognition of peak diversity among restaurants operated under the same brand would produce an annual savings of $32,544.

The primary reason for this cost difference is that the AFFIRM Members are treated for rate making purposes as if they were hundreds of unaffiliated small retail customers. This treatment as individual customers is inconsistent with the collective manner in which the AFFIRM Members are treated in competitive markets by almost all energy suppliers, and is further inconsistent with the collective treatment that the AFFIRM Members enjoy from the suppliers of almost all other products purchased by such companies.

Q. WHAT ACTION DOES AFFIRM ASK OF THE COMMISSION WITH RESPECT TO THE ISSUE OF THE DEVELOPMENT OF MULTI-LOCATION RATES?

A. The Commission is aware that a primary purpose of rate regulation is to attempt to create, in the absence of competition for the regulated entity, the same competitive pressures that would exist if competition were present. The Commission should take notice that in states where electric service or natural gas service has been deregulated, it is common for energy suppliers to actively seek to provide service to these multi-locations customers under pricing schemes that recognize the aggregate size and usage characteristics of these customers. For that reason, AFFIRM requests that the Commission direct the Company to engage in good faith negotiations with representatives of AFFIRM such that multi-location rates can be developed and considered in this rate proceeding or in subsequent rate proceedings of the Company.

Q. ARE THERE OTHER ASPECTS TO THE DEVELOPMENT OF MULTI-LOCATION RATES THAT THE COMMISSION, AND IN TURN THE COMPANY, SHOULD CONSIDER?

A. Yes. Another important aspect of the consideration of multiple location rates is that the customers to whom such rates would be available should be defined as all premises operated as a single brand under common ownership or under common control via written franchise agreements with a single controlling entity.

Q. WHY SHOULD ALL PREMISES THAT ARE OPERATED AS A SINGLE BRAND UNDER COMMON CONTROL PURSUANT TO FRANCHISE

AGREEMENTS WITH A SINGLE CONTROLLING ENTITY BE ALLOWED TO USE A MULTIPLE LOCATION RATE/

A. The operation of certain premises under franchise agreements is an integral component of the business operation of many recognized brands, including all of the AFFIRM Members. Franchise holders operate their premises subject to the same degree of operational control by the controlling entity as the controlling entity exercises over its company-owned premises. Such controls include, but are not limited to, signage, appearance of premises, training of employees, products offered, product pricing, and adherence to the policies and rules of the controlling entity as set forth in written documents. In essence, the controlling entity holds every incidence of ownership in the premises, with the exception of title to the premises. This is the reason that customers are unable to distinguish between stores operated by the company versus stores operated by franchisees.

The existence of a franchise arrangement should properly be viewed not as an ownership issue, but rather as an alternative form of financing. The franchisee provides the initial financing, and earns a return on that investment. The controlling entity (the franchisor) is relieved of the burden of financing, and receives revenues from franchise fees and royalties instead of through the direct operation of the premises. One of the elements of the value of a franchise or brand is the ability to realize reduced operational costs through widespread economies of scale, including the collective purchase of goods and services such as energy products and services. This value is often directly reflected in the level of franchise fees collected by the controlling entity.

Q. DOES AFFIRM WISH TO COMMENT ON THE COST OF SERVICE METHODOLOGY SUGGESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes. In this proceeding, the Company proposes that fixed production capacity costs should be allocated based on 12 CP and 50% AD rather than the historical allocation factor of 12 CP and 1/13th AD. The Members of AFFIRM object to the Company's proposed methodology and urges the Commission to reject this proposal and instead to adopt the methodology that has historically been used. The 12 CP and 1/13th AD methodology for allocating fixed production capacity costs has been a foundation for electric rate regulation in Florida, as evidenced by the fact that the MFRs that must be submitted by the Company require cost of service data to be submitted using the 12 CP and 1/13th AD allocator.

The testimony of Company Witness Slusser advocates the use of the 12 CP and 50% AD methodology on the basis that it "is intended to provide a better matching of the allocation of costs and benefits to customer rate classes". The Members of AFFIRM agree that the cost of service study should provide the optimum matching of the allocation of costs and benefits to customer rate classes. However, the issue to be addressed by the Commission in this matter is to choose the methodology that best accomplishes the objective of matching costs and benefits.

The Company argues that the methodology that provides a 50% weighting to energy in the allocation of fixed production capacity costs is appropriate because generation investment strategies are different today than the strategies used in developing the Company's generation fleet thirty years ago. That premise fails on two counts. First, a significant portion of the generation related capacity costs that are being allocated today arose from the generation related investment strategies of thirty years ago, and thus should continue to be allocated on the same basis as the decisions to make those investments. As explained by Mr. Slusser, the methodology developed by the Commission at that time was the 12 CP and $1/13^{th}$ method, and as those investments remain in place today, such investments should be allocated on the basis that was adopted at the time of investment.

Second, and equally important, the changes in generation investment strategies that have occurred over time may reflect differences in the choices of generation resources based to fuel costs and environmental considerations, but at the foundation of such generation planning is the proposition that whatever generating resources are developed must be capable of reliably serving the expected loads of the Company. As the underlying foundation for generation investment planning remains the objective of reliably serving loads, it is inappropriate to provide such a disproportionate weighting to energy usage in the allocation of fixed production capacity costs.

Q. Are there other factors that should be considered by the Commission in the selection of the appropriate methodology for allocating fixed production capacity costs?

A. Yes, there are. The Commission should be sensitive to the fact that price signals for the consumption of electric energy are becoming increasingly important in the way that customers use electricity. Accordingly, when rates are developed, the Commission should take great care in assuring that rates are established and structured in a manner that most closely aligns the price with the related costs.

The failure properly to align prices with related costs results in sub-optimal price signals and inappropriate usage of energy. Customers that receive a price signal that does not reflect the full cost of service have an incentive to overuse energy, instead of foregoing energy usage or undertaking investments that will suppress energy consumption. Correspondingly, customers that receive a price signal that reflects more than the full cost of service have an incentive to forego energy use that would be economically productive. The objective of economic efficiency is satisfied best when prices directly reflect related costs.

The use of the allocation method proposed by the Company is not supported by economic principles and does not result in prices that reflect related costs, and accordingly should be rejected by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CHAIRMAN CARTER: Ms. Kaufman, you're recognized.

MS. KAUFMAN: Thank you, Mr. Chairman. FIPUG would move to enter into the record the direct testimony of Martin J. Marz. And I want to point out so the record is clear that we have withdrawn his testimony on Page 7, Lines 15 to 20, and Page 8, Lines 1 to 9, in keeping with the discussion we had, I guess it was at the beginning of the hearing --

CHAIRMAN CARTER: Okay.

MS. KAUFMAN: -- in regard to the revised forecast.

CHAIRMAN CARTER: Okay. I'm sensing agreement. Okay. Affirmation. Okay. The prefiled testimony of the witness will, the prefiled testimony of the witness with the corrections will be entered into the record as though read.

Okay. Exhibits?

MS. KAUFMAN: Mr. Marz has Exhibits 180 through 185.

CHAIRMAN CARTER: Okay. Let me get over there. 180 through 185. Are there any objections?

MR. BURNETT: No, sir.

CHAIRMAN CARTER: Without objection, show it done.

(Exhibits 180 through 185 marked for identification and admitted into the record.)

Anything further, Ms. Kaufman, on Witness Marz?

MS. KAUFMAN: No, Mr. Chairman. Thank you.

1. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Martin J. Marz; J. Pollock, Incorporated, 1525 Lakeville Drive, Kingwood, Texas 77339.

Q. **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A. I am an Energy Advisor and Senior Consultant for J. Pollock, Incorporated.

Q. **WHAT IS YOUR EDUCATIONAL BACKGROUND?**

A. I have a Bachelor of Arts in Political Science from the University of Akron, and a *Juris Doctor* from the University of Akron, School of Law.

Q. **PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.**

A. I have 27 years of experience in the energy industry (both in gas and electricity matters). This includes participation in various regulatory proceedings. More information is provided in **Appendix A**.

Q **ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). Participating FIPUG members purchase electricity from Progress Energy Florida (PEF).

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A I will address the following issues:

- Adjustments to certain test year operation and maintenance (O&M) expenses;
- Incentive compensation; and
- PEF's proposed increase in the annual storm damage accrual.

Q **ARE YOU FILING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?**

A Yes. I am filing **Exhibits MJM-1** through **MJM-5**. These exhibits were prepared by me or under my direction and supervision.

Summary

Q **PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A First, I am recommending adjustments to the following Test year O&M expenses:

- $17.65 million for Transmission and Distribution Overhead Line maintenance expenses;
- $15 million for Production maintenance expense.

These adjustments are essential to correct a severe "spike" in PEF's projected O&M expenses. Specifically, test year transmission and distribution O&M would increase by 60% and 37%, respectively, relative to actual/projected expenses for the period 2006 through 2009, under PEF's proposal. This includes 47% (transmission) and 44% (distribution) increases from 2009 to 2010. Similarly, steam and other generation maintenance expense would increase by 36% relative to 2009 and by 57% relative to the average of the most recent four- year period. These increases are excessive and have not been supported. Because base rates established in this proceeding are likely to remain in effect for a period well beyond 2010, the recommended adjustments are necessary to ensure that rates are representative of what is likely to occur.

Second, I am recommending $18.25 million of adjustments to exclude incentive compensation that is specifically targeted to achieving financial goals. This includes all of the executive/senior management incentive compensation and 50% of the incentive compensation for other management and non-management employees. These costs benefit Progress (the holding company) shareholders and should not be subsidized by PEF ratepayers.

Finally, PEF's proposed $10 million increase in annual contributions to the storm reserve should be rejected because the current $133 million storm reserve balance is sufficient to cover all but the most serious of storm events. PEF's proposal clearly violates the Commission's existing framework, which is predicated upon a multi-faceted approach to funding storm damage. This approach does not rely solely on the storm reserve accrual to provide coverage for storm damage. Even without any additional contributions, the storm reserve is adequate to provide coverage for the estimated annual average loss for the next eight years. Thus, contributions should cease.

2. TEST YEAR

Background

Q **WHAT TEST YEAR IS PROGRESS ENERGY FLORIDA (PEF) PROPOSING IN THIS PROCEEDING?**

A PEF is proposing to use calendar year 2010 as its test year.

Q **EXPLAIN THE CONCEPT OF THE TEST YEAR.**

A A test year is a period of 12 months (sometimes but not always a calendar year) used to measure the utility's revenues and expenses for the purpose of setting base rates. In order to set rates that provide the utility a reasonable opportunity to earn a reasonable return on its used and useful investment in property and equipment, the test year must be representative of and reflect the conditions expected to exist during the period when new base rates are expected to be in effect. Thus, non-recurring and other atypical items (both on the revenue and expense side of the equation) need to be adjusted to reflect expected conditions.

Q **IS PEF PROJECTING A CONTINUATION OF THE GROWTH IN SALES THAT HAS OCCURRED IN THE MOST RECENT 10-YEAR PERIOD?**

A No. PEF has experienced sales growth of 2.0% through 2008. In the short run, 2009 and 2010, PEF is projecting sales growth of only 0.1% and 0.4%, respectively. Long-term sales are projected to grow 1.7% per year. (Progress Energy Florida, Inc., *Ten-Year Site Plan*, April 2009).

~~**Q DOES SLOWER PROJECTED GROWTH IN THE TEST YEAR RAISE ANY CONCERNS?**~~

~~A Yes. Base rates reflect a utility's test year costs divided by test year sales. The higher the costs (*i.e.*, the numerator) and/or the lower the sales (*i.e.*, the denominator), the higher the rates. All other things being equal, higher rates will provide the utility the opportunity for increased revenues and increased returns to shareholders. Given that PEF is forecasting slower than normal sales growth and substantial increases in certain O&M expenses, the Commission should review the filing with some degree of skepticism.~~

Q ARE PROJECTED TEST YEAR SALES THE ONLY FACTOR THE COMMISSION SHOULD CONSIDER IN SETTING RATES IN THIS PROCEEDING?

A No. The Commission also needs to give consideration to the time frame that new base rates may be expected to be in effect. That is, based on past history, the rates set in this proceeding may very well remain in effect for a period out to 2014-2015. Setting rates based on depressed sales will create an enhanced opportunity for PEF to increase its overall shareholder return and charge ratepayers rates that are potentially unjust and unreasonable. Additionally, the overall growth in expenses needs to be examined in detail to ensure that the projected level of expenses is representative of what may be incurred over more than one year.

Q HAS THE COMPANY INDICATED HOW LONG IT ANTICIPATES THAT THE PROPOSED RATES MAY BE IN EFFECT?

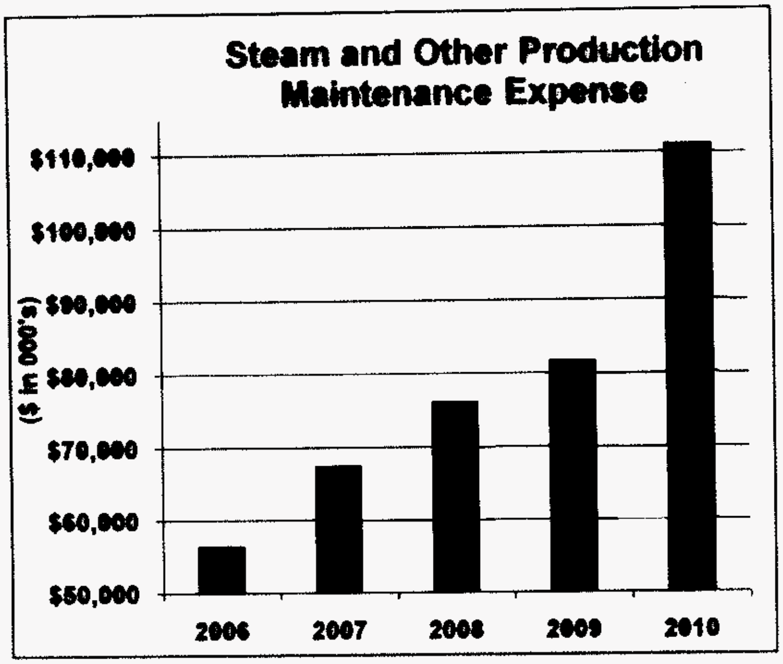
A No. However, PEF's last fully litigated rate case was in 1993. (*PEF Petition to Increase Rates* at 5). Because it may be some time before PEF's next full base rate review, it is critical to ensure that test year projections, which form the basis for the proposed rates, are accurate.

Q DESPITE THE SLOWER GROWTH, IS PEF PROJECTING SUBSTANTIAL INCREASES IN TEST YEAR O&M EXPENSES RELATIVE TO PAST YEARS?

A Yes. PEF's test year O&M expenses are dramatically higher than the corresponding expenses for the period 2006 through 2009, as shown in the table below:

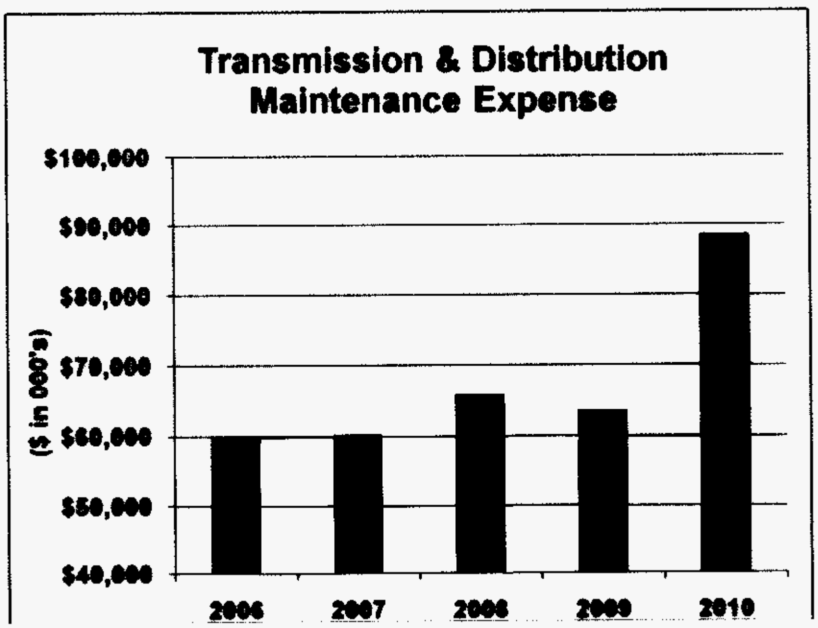
Projected Increases in O&M Expenses ($Millions)				
Function	**Average 2006-2009**	**Test Year**	**Increase**	**Percent Increase**
Production Maintenance Steam and Other	$70.6	$111.1	$40.6	57%
Transmission	$14.0	$22.4	$8.4	60%
Distribution	$48.4	$66.2	$17.8	37%

Annual non-fuel production maintenance expenses are shown in the following tables. As can be seen, for steam and other generation maintenance expense, the largest increase would occur from 2009 to the test year ($29.3 million, or 36%). *See*, **Exhibit MJM-2**. This increase is even more remarkable given that PEF is not projecting to add generation capacity in the test year.



1 A similar spike is projected in test year transmission and distribution O&M

2 expenses, as shown below.



3 (Amounts from MFR Schedule C-6 Account Nos. 568-573 and 590-598).

The test year spikes highlight the need for the Commission to carefully review the overall expenses reflected in PEF's test year.

Q **DO YOU HAVE ANY OTHER CONCERNS REGARDING PEF'S 2010 TEST YEAR BUDGET NUMBERS?**

A Yes. The 2010 budget was prepared in 2008 as part of a two-year budget. (*Direct Testimony of Peter Toomey* at 14). I would not expect that the test year expenses will be the actual expenses under which PEF operates in 2010. In my experience, corporations go through an annual budget process for purposes of establishing operating budgets for the upcoming year. Further, given the challenging economic times, it would be reasonable for PEF to have semi-annual or even quarterly reviews of the existing budget, with senior management putting pressure on the various operating groups or departments to reduce expenditures in order to maintain or increase overall earnings to shareholders. In fact, Mark Mulhern—Chief Financial Officer of Progress Energy, Inc. (the parent of PEF), in a presentation to analysts and investors made at Progress Energy Inc.'s Analyst and Investor Day on February 27, 2009—indicated that there was significant "belt tightening" efforts underway along with an effort to reduce 2009 budgets. Given the current economic conditions, there will more than likely be a similar effort directed at 2010 expenditures (see: http://www.progress-energy.com/investors/newsevents/webcasts/index.asp).

Q **WILL PEF BE ADDING GENERATION DURING AND AFTER THE TEST YEAR THAT WILL CAUSE THE NEED FOR RATE RELIEF?**

A No. PEF's next capacity addition is the up-rate at the Crystal River 3 Plant planned for 2011. These costs will be recovered through the Nuclear Cost Recovery clause and will not impact base rates. The next planned capacity additions occur in 2014 and 2015. (Progress Energy Florida Inc., *Ten-Year Site Plan,* April 2009 *at* 3-2).

Q **IS IT LIKELY THAT THE BASE RATES IMPLEMENTED IN THIS PROCEEDING WILL REMAIN IN EFFECT BEYOND 2010?**

A Yes. Given that there are no substantial generation additions impacting base rates until 2014, the proposed kWh sales levels reflected in the filing and PEF's history of rate requests, I believe that any rate change approved by the Commission will likely remain in place for a minimum of three years, if not longer. This makes it important that the sales (billing determinants) and expenses be set at a level that will result in just and reasonable rates for a period beyond 2010.

O&M Adjustments

Q **WHAT ADJUSTMENTS SHOULD BE MADE TO TEST YEAR O&M EXPENSE?**

A In order to make the test year more representative, the following reductions should be made to O&M expenses:

- **$3.75 million for FERC Account No. 571 – Transmission Overhead Lines Maintenance;**
- **$13.9 million for FERC Account 593 – Distribution Overhead Line Maintenance;**

- $15 million adjustment to Steam and Other Generation Maintenance expenses.

Each of the proposed adjustments is discussed in greater detail below.

Maintenance of Overhead Lines

Q WHAT ARE FERC ACCOUNT NOS. 571 AND 593?

A FERC Account No. 571 is for the recording of expenses associated with maintenance of overhead transmission lines. FERC Account No. 593 is for the recording of expenses associated with the maintenance of overhead distribution lines. Included within the type of expenses to be recorded in the two accounts are maintenance costs associated with tree trimming and vegetation removal and management.

Q HOW MUCH HAS PEF INCLUDED IN THE RESPECTIVE ACCOUNTS FOR THE 2010 TEST YEAR?

A **Exhibit MJM-1** shows budgeted amounts for the test year of $11.8 million in Account 571 and $45.8 million for Account 593.

Q WHAT DO YOU RECOMMEND FOR THE TWO ACCOUNTS?

A I recommend that these expenses be reduced by $3.75 million and $13.9 million, respectively. This would result in adjusted expenses of $8.05 million and $31.9 million for Account 571 and Account 593, respectively.

Q WHAT REASON HAS THE COMPANY PROVIDED FOR THE INCREASES IN THOSE TWO ACCOUNTS?

A PEF witness Joyner attributes the large increase to additional cost of vegetation management related to certain Commission initiatives pertaining to hurricane preparation and storm hardening.

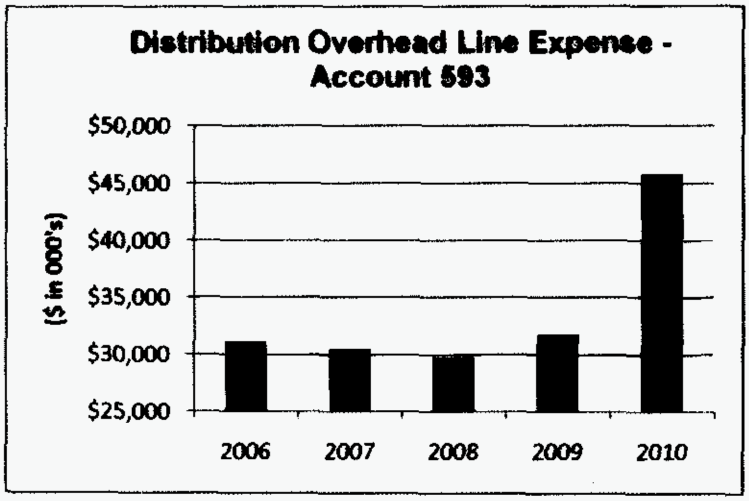
Q ARE HURRICANE PREPARATION AND STORM HARDENING INITIATIVES NEW UNDERTAKINGS?

A No. The Commission established a ten-step program to encourage vegetation management in 2006 following a series of tropical storms and hurricanes that struck Florida during the 2004 – 2005 time frame. In 2006, the Commission "issued Order No. PSC-06-0351-PAA-EI, requiring the investor-owned electric utilities to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives on or before June 1, 2006." (*Order No. PSC-06-0947-PAA-EI, Docket No. 060198-EI*, November 13, 2006). By 2006, PEF had already undertaken a review of its vegetation management policy and implemented an integrated vegetation management (IVM) program. The IVM program was approved by the Commission in late 2006. *(Id.)* Separately, in 2007, the Commission approved PEF's storm hardening plan. (*Order No. PSC-07-1021-FOF-EI* Docket *No.* 070288-EI, December 28, 2007). As such, implementation of both the IVM program and storm hardening began well before 2010.

Q WHAT DOES THE IMPLEMENTATION OF THE INTEGRATED VEGETATION MANAGEMENT PROGRAM IN 2006 SUGGEST FOR COSTS IN 2010?

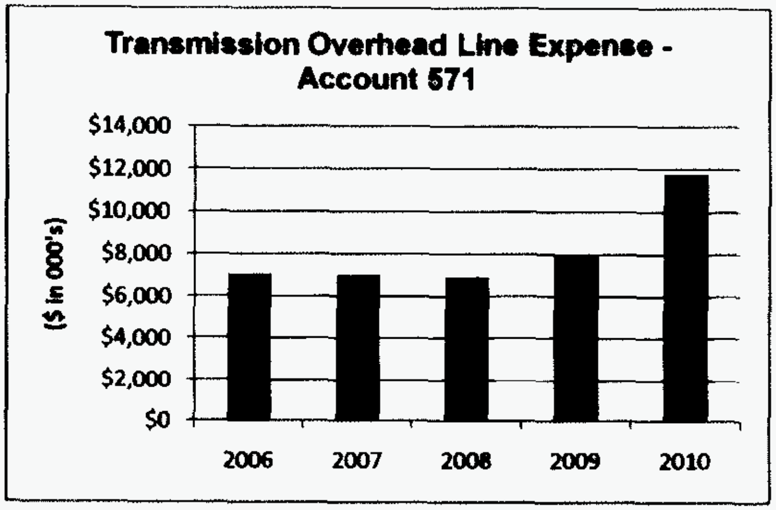
A First, the overall increase in costs associated with the IVM program should already be reflected in actual tree trimming and vegetation management expenses in both Accounts 571 and 593 as far back as 2006. Actual Account

593 costs remained relatively constant from 2006 through 2008 up to and including the budgeted 2009 expense, as shown on the table below. However, PEF is projecting a substantial increase in 2010.



(MFR Schedule C-6).

Similarly, as shown in the table below, Account. 571 costs increased by $3.8 million (47%) from 2009 to 2010, and $4.5 million (62%) higher than the 2006-2009 average expenses, as shown in **Exhibit MJM-1**.



Given that the IVM program was approved and implemented in 2006, a substantial cost increase should not only now be reflected in the test year expenses. In fact, comparing actual to budgeted expenses on MFR C-6 for the two accounts, it is clear that there has already been a substantial increase in costs for maintenance of overhead lines beginning in 2007.

This spike in overhead line expense creates a separate question: Did PEF implement the IVM in 2006 as claimed and the storm hardening program following Commission approval in 2007? If so, there should not be a spike in overhead line maintenance in the 2010 test year. The cost increases associated with those programs should be reflected in PEF's actual 2008 and 2009 budget expenses. Thus, the projected increase in test year costs cannot be explained by the IVM and storm hardening programs. Therefore, I recommend that 2009 levels be used for the test year expenses for Accounts 571 and 593. This would reduce O&M expenses by $3.75 million for Account 571 and $13.9 million for Account 593.

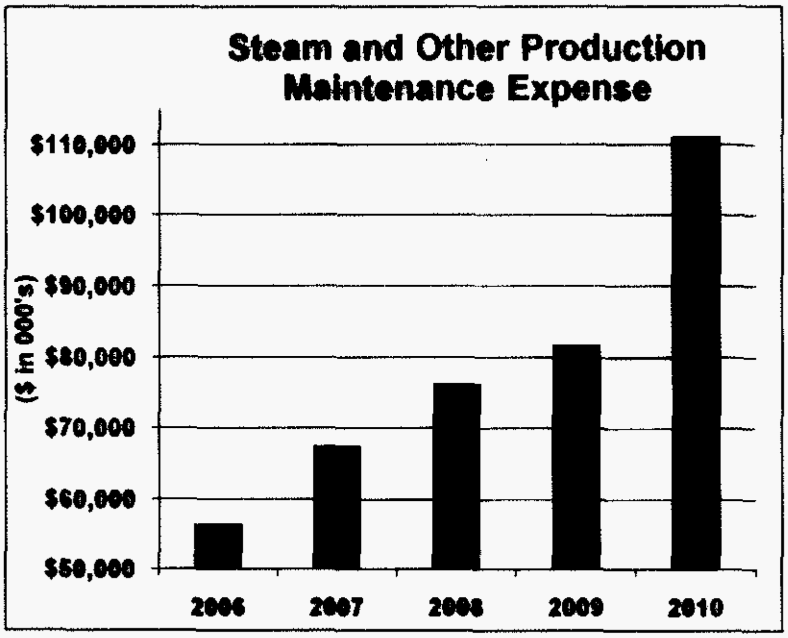
Production Maintenance Expenses

Q WHAT ARE THE STEAM AND OTHER PRODUCTION MAINTENANCE COSTS ON A TOTAL COMPANY BASIS REFLECTED IN THE FILING?

A As shown on Schedule MFR C-6, the 2010 test year Steam and Other Production Maintenance expenses are $111.1 million.

Q WHY ARE YOU PROPOSING TO ADJUST PRODUCTION MAINTENANCE EXPENSES?

A The test year steam and other generation maintenance expenses are overstated. Comparing the 2010 test year expense to the 2009 budgeted numbers, PEF is projecting a $29.3 million or a 36% increase. The corresponding four-year average (2006-2009) increase is $40.6 million or 57% as shown on **Exhibit MJM-2**. The following table highlights the overall increase in production maintenance expenses year over year.



Q WHAT IS CONTRIBUTING TO THESE SUBSTANTIAL INCREASES?

A PEF witness Sorrick identifies an accelerated outage at Crystal River 4 (CR4), for major boiler and turbine maintenance that will cost $9.3 million. Thus, it accounts for 28% of the projected increase in Steam Generation Maintenance expense.

Q WAS THE CR4 OUTAGE ORIGINALLY SCHEDULED FOR THE TEST YEAR?

A No. The CR4 outage was moved to 2010 from a later time period (sometime after 2010). (*Direct Testimony of David Sorrick* at 27).

Q DOES THE CR4 OUTAGE OCCUR ANNUALLY?

A No. PEF has acknowledged that this particular outage occurs every nine years:

> The type of work that will be performed during the boiler outage includes scaffolding the boiler, inspecting the boiler and repairing the items identified during the inspection. The type of work that will be performed during the turbine outage, which is typically performed every 9 years, includes the inspection and repairs of the internal and external steam components. Therefore, these outages have been scheduled to be performed during the spring of 2010 at the same time the FGD and SCRs will be installed. PEF would normally schedule these maintenance outages in the normal course of its operations but PEF decided to accelerate them to capture synergies in outage costs with the outage for the FGD and SCR work as well as minimize lost generation instead of taking an additional outage. (*PEF Response to OPC Interrogatory No. 260)*

Q IS IT APPROPRIATE TO REFLECT THE FULL COST OF THIS OUTAGE FOR RATEMAKING PURPOSES?

A No. Even assuming that the outage should be recognized, the full cost should not be included in setting rates in this case. Doing so assumes that PEF would incur the full outage cost annually instead of once every nine years. Thus, PEF would over-recover its costs. At most, only 11.1% (one-ninth) of the CR4 outage costs should be recognized for ratemaking purposes.

Q ARE THERE OTHER EXPENSE INCREASES REFLECTED IN THE 2010 TEST YEAR BUDGET?

A Yes. There are also additional planned outages at certain of the combined cycle and combustion turbine plants increasing overall O&M costs. Mr. Sorrick also points to increased costs at the Hines Power Block and overhauls and increased staffing for the repowered Bartow facility. Finally, there is also a $5.3 million increase for emerging equipment issues and other repairs.

Q ARE THERE ANY OTHER QUESTIONABLE COSTS?

A Yes. PEF has included a $5.3 million dollar expense for "emerging equipment" costs and other items. In reviewing the Testimony of Company witness Sorrick and PEF's Response to OPC Interrogatory No. 260, I conclude that the amount is a contingency put in to preserve options. In response to OPC Interrogatory No. 260, PEF indicates that "This funding would be used for forced outage repairs or to take advantage of opportunities to enhance the fleet." From this statement I can only conclude that the amount is a "contingency expense" – something placed in the budget in case expense estimates are too low.

Q WHAT ADJUSTMENTS SHOULD BE MADE TO PRODUCTION MAINTENANCE EXPENSES?

A I recommend that an overall $15 million reduction be made to the combined Steam and Other Generation maintenance expense. The adjustment represents an approximate 50% reduction in PEF's projected increase in these expenses from 2010 over 2009. Even at the lower recommended level, it would still represent a 17% increase over PEF's 2009 budget and a 36% increase over the four- year average (2006-2010) expense. **Exhibit MJM-3** highlights the various levels of Steam and Other Generation expenses.

3. INCENTIVE COMPENSATION

Background

Q **WHAT IS MEANT BY INCENTIVE COMPENSATION?**

A Incentive compensation is the additional compensation paid to employees to encourage certain behavior and/or results. It is paid as a reward for the individual and business group achieving pre-established goals and objectives. Payment is discretionary and contingent on the employee/business unit achieving the goals.

Q **IS PEF PROPOSING TO RECOVER COSTS INCURRED UNDER VARIOUS INCENTIVE COMPENSATION PROGRAMS IN BASE RATES?**

A Yes. In this proceeding, PEF has proposed to include a total of $33.9 million of incentive compensation in labor costs as a test year expense. (*MFR Schedule C-35).*

Q **WHY IS INCENTIVE COMPENSATION AN ISSUE IN SETTING RATES?**

A Not all incentive compensation is beneficial to ratepayers. As I discuss below, incentive compensation based on achieving certain operational goals may be a reasonable and necessary expense, which may benefit ratepayers. However, incentive compensation that is targeted to achieve certain financial goals is only for the benefit of shareholders and provides little if any benefit to ratepayers. Thus, the latter expenses should not be charged to ratepayers.

Q **SHOULD PEF BE ALLOWED FULL RECOVERY OF ALL PROJECTED INCENTIVE COMPENSATION PAYMENTS?**

A No. Incentive compensation that is based on achieving certain financial goals of Progress, the parent of PEF, should be disallowed on the basis that it benefits only shareholders not ratepayers. Therefore, I recommend the following disallowances related to incentive compensation:

- $2.6 million of incentive compensation budgeted for executives and senior management (executives).
- $15.6 million (or 50%) of the incentive compensation applicable to other management and non-management.

My recommendation would result in an overall reduction in incentive compensation of $18.25 million from the level shown on Schedule MFR C-35. *See*, **Exhibit MJM-4**.

Q **WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

A All of the *executive/senior management incentive compensation* is contingent and based upon the earnings (operating income or eamings per share (EPS)) of Progress. In the case of other management and non-management employees, at least 50% of the incentive compensation is based upon Progress achieving a certain level of EPS.

PEF Proposal

Q **WHAT INCENTIVE COMPENSATION PLANS DOES PEF OFFER ITS EMPLOYEES?**

A PEF has several incentive compensation plans: (1) the Executive Incentive Plan (EIP), which applies to Executives, (2) the Senior Management Performance

Sub-Share Plan, which applies to senior managers, (3) the Management Incentive Compensation Plan (MICP), which applies to other managers, and (4) the Employee Cash Incentive Plan (ECIP), which applies to all other employees.

Q HOW DO EACH OF THE VARIOUS INCENTIVE COMPENSATION PLANS WORK?

A Under the EIP, the incentive payment is at the discretion of the Organization and Operations Committee of the Board of Directors of Progress (Committee), with the potential award pool to be funded from up to 1% of the operating income of Progress, the parent of PEF. (*PEF Response to OPC Request to Produce No. 116).*

Under the Senior Management Performance Sub-Share Plan, senior managers may receive stock awards. The level of the stock award payout is tied to a combination of the total shareholder return and the rate of growth in the ongoing earnings per share of Progress during the performance period. Both of these measures are based on the financial results of Progress.

Under the MICP, payout is based in part on EPS of Progress and upon "legal entity" EBITDA (this measure looks at Earnings before Interest, Taxes, Depreciation and Amortization the "legal entity," the operating company, such as PEF or Progress Carolina, as applicable;). (*PEF Response to OPC Request to Produce No. 116).*

Finally, under the ECIP, any payout is based upon two equally weighted components. One component is based upon an EPS target for Progress, with an additional percentage allowable to all employees at the CEO's discretion. *(Id.)*

The other half of the payout is tied to business unit goals and the individual's performance in helping the business unit achieve the goals. Individuals may receive up to 150% of their targeted award, depending upon performance in both categories. (*Id.*) To the extent that only the minimum targeted EPS goal for Progress is met, any payment under the Progress benchmark portion of the award would be zero. Further, to the extent the minimum EPS goal for Progress is not achieved, not only would the portion contingent on Progress achieving its EPS goal not be paid, but the overall business unit portion of the award, referred to as the Operational Excellence portion of the award, may also be reduced by up to 15% (*Id.*).

Q WHAT PORTION OF THE TEST YEAR INCENTIVE COMPENSATION IS RELATED TO MANAGEMENT AND NON-EXECUTIVE COMPENSATION?

A Total incentive compensation reflected on MFR Schedule C-35 is $33.9 million, of which $2.6 million is for executive incentive compensation and $31.3 million is for incentive compensation for management and non-executive employees. This is shown in **Exhibit MJM-4**.

Q HOW IS PEF TREATING THE INCENTIVE AWARDS FOR PURPOSES OF DETERMINING EXPENSES FOR RATEMAKING PURPOSES?

A PEF has assumed that the total payout for 2010 will be its full budgeted amount of $33.9 million across all employee classes and has sought to include that full amount in the setting of rates. (*MFR Schedule C-35*).

Q **IS THE PAYMENT OF THE INCENTIVE COMPENSATION GUARANTEED UNDER ANY OF THE PLANS?**

A No. With the exception of the ECIP, the other programs are discretionary and contingent upon the earnings target(s) being met. Under the ECIP, at least one half of the potential payout is contingent on the EPS minimum target for the year being exceeded, and as to the remaining portion of the payout, it is contingent upon the employee's performance and that of the business unit in achieving the business unit goals.

Q **WHY IS THE CONTINGENT NATURE OF THE PAYMENT AN IMPORTANT CONSIDERATION IN THE RATE SETTING PROCESS?**

A PEF is assuming that all goals and objectives will be met, and it will make the payments. By definition, a contingent payment is one that may not be required. Incentive compensation by definition is not guaranteed. As such, the inclusion of 100% of the potential incentive compensation dollars simply provides a fund that management may choose to use to boost earnings.

Q **DOES THE CONTINGENT NATURE OF THE PAYMENT ALSO JUSTIFY A DISALLOWANCE?**

A Yes. Because the payment is contingent, it is not known and measurable. As a general rule, unless an expense is subject known or measurable it should not be allowed. In this case, the total level of payment cannot be known until after the end of the performance period for which any payment is to be made.

Q HOW DO YOU RECOMMEND THAT THE INCENTIVE COMPENSATION FOR SENIOR EXECUTIVE MANAGEMENT BE TREATED FOR RATEMAKING PURPOSES?

A All of the compensation paid to executives under the EIP and the Performance Sub-Share Plan should be excluded from the calculation of operating expenses and rates. All of that compensation is predicated upon the earnings of the parent company, Progress, and not tied to the results of the operating company, PEF. Therefore, none of these costs should be borne by ratepayers. This results in a disallowance of $2.6 million.

Q HOW DO YOU RECOMMEND THAT THE INCENTIVE COMPENSATION FOR OTHER MANAGEMENT AND NON-MANAGEMENT EMPLOYEES BE TREATED FOR RATEMAKING PURPOSES?

A I recommend that 50% of the total incentive compensation for management and non-management employees in the amount of $15.6 million be removed from labor expense. Incentive compensation under the MICP is based on a combination of the EPS of Progress and upon "legal entity" (which appears to be a reference to the operating company for which the employee works) EBITDA. (*PEF Response to OPC Request to Produce No. 116).* Each of these items benefits shareholders. Similarly, 50% of any award under the ECIP is based upon Progress achieving a minimum EPS level. Absent Progress achieving that minimum level, a payout under the ECIP would be 50% or more lower than the target maximum award level. To the extent that the reward is for enhancing shareholder returns, the payment is much more in the nature of a profit sharing between shareholders and management. To the extent that employees are being paid for enhancing value to shareholders, it is shareholders that should bear the overall responsibility of such costs.

Q **IS THERE ANY PRECEDENT FOR EXCLUDING A PORTION OF INCENTIVE COMPENSATION WHEN SETTING RATES?**

A Yes. The Public Utility Commission of Texas (PUCT) has disallowed the portion of incentive compensation tied to corporate financial objectives. (*See,* Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Final Order* issued August 15, 2005 at paragraphs 164-170.) Specifically, in the AEP Central case, the PUCT permitted inclusion of the incentive compensation to the extent that it was tied to operational factors. To the extent the compensation was the result of financial measures, the payment was viewed as beneficial to shareholders and not ratepayers. In permitting some recovery of incentive compensation, the PUCT concluded:

> The financial measures are of more immediate benefit to shareholders, and the operating measures are of more immediate benefit to ratepayers.
>
> Incentives to achieve operational measures are necessary and reasonable to provide T&D utility services, but those to achieve financial measures are not. (*__Id__. at 169-170)*

Likewise, the Wyoming Public Service Commission in an Application of PacifiCorp for a retail increase chose to disallow 50% of incentive compensation because business unit and corporate incentives are primarily for the benefit of shareholders. (*In the Matter of the Application of PacifiCorp. for a Retail Electric Utility Rate Increase of $41.8 Million per Year*, 232 P.U.R. 4th at 295 (2004).

Q **HAS THIS COMMISSION RECENTLY ADDRESSED THE ISSUE OF INCENTIVE COMPENSATION THAT MAY BE INCLUDED IN THE CALCULATION OF RATES?**

A Yes. In the recent Tampa Electric Company (TECO) rate case, the Commission excluded from incentive compensation that portion of incentive compensation for senior officers that is related to TECO's parent company's earnings, stating:

> We also find, however, that the incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent Company TECO Energy. (*In re: Tampa Electric Company*, FPSC Order No. PSC-09-0283-FOF-EI at 58).

In the case of PEF, a large portion of incentive compensation for all levels of employment is tied directly to the earnings of the parent company, Progress. and not the results of PEF or upon measures that benefit ratepayers of PEF.

Q **IN CONCLUSION, WHAT IS AN APPROPRIATE DISALLOWANCE FOR INCENTIVE COMPENSATION FOR EXCLUSION FROM OPERATING EXPENSES?**

A All of the incentive compensation included in the test year for executive management and one half of the incentive compensation for other management and non-management employees should be excluded from the calculation of the rates in this proceeding, resulting in a total reduction of $18.25 million to incentive compensation shown on MFR Schedule C-35.

4. STORM RESERVE ACCRUAL

Background

Q WHAT IS A STORM RESERVE?

A Under Rule 25-6.0143, Florida Administrative Code, electric utilities are allowed to establish a "separate subaccount . . . that portion of Account No. 228.1, which is designated to cover storm-related damages to the utility's own property or property leased from others that is not covered by insurance." (*Direct Testimony of Company witness Peter Toomey*, at 25).

Q WHAT IS THE CURRENT STORM RESERVE LEVEL?

A The balance in the reserve is approximately $133 million. This takes into account Tropical Storm Fay expenses of approximately $10 million, which had not been charged to the storm reserve as of last March.

Q HOW DID YOU CALCULATE THAT AMOUNT?

A PEF Response to OPC Interrogatory 153 shows a reserve of $140 million as of March 2009 without any reduction for Tropical Storm Fay. PEF's Responses to OPC Interrogatory 109 and 355 indicate that amounts for Tropical Storm Fay of approximately $10 million had not yet been charged to the storm reserve. Reducing the March 31 balance by the $10 million and adding $460,000 per month produces a balance of approximately $133 million as of July 31, 2009.

Q **HOW IS THE STORM RESERVE FUNDED?**

A It has been funded by ratepayer contributions through the agreed upon continuation of a surcharge designed to recover the costs of the 2004 hurricane season (*Order No. PSC-06-0772-PAA-EI, Docket No. 041712-EI* September 18, 2006) and through ratepayer contributions that the Commission authorizes in setting base rates. Ratepayers currently contribute $6 million per year to the storm reserve.

Q **DOES THE COMMISSION HAVE A FRAMEWORK FOR STORM RESTORATION COST RECOVERY?**

A Yes. According to the recent order in the TECO rate case, the following is the framework in which the Commission addresses the storm restoration cost issue:

> We have established a regulatory framework consisting of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all storm years; and, (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve. (*In re Tampa Electric Company*, FPSC Order No. PSC-09-0283-FOF-EI at 17).

Q **WHO ULTIMATELY ASSUMES THE RISK OF LOSS FROM STORM DAMAGE UNDER THE EXISTNG COMMISSION FRAMEWORK?**

A PEF's customers ultimately bear all of the risk of losses due to hurricanes and other storms:

> . . . under the current approach to the recovery of storm restoration costs, the risk associated with a lower reserve level (i.e., the possibility of storm restoration costs exceeding the Reserve, leading to subsequent customer charges) and the risk associated with a higher reserve level (i.e., paying charges now for storm restoration costs that do not materialize) is completely

> borne by FPL's customers. The customers represented in this proceeding have made clear that they would rather pay to fund the Reserve to a lower level now and risk future rate volatility than pay to fund the Reserve to a higher level before future storm restoration costs have been incurred. (*In re Florida Power & Light Company*, FPSC Order No. PSC-06-0464-FOF-EI, *at paragraph* 57).

As such, PEF is at little or no risk for recovering storm restoration costs regardless of the amount in the storm reserve. Put simply, from a ratepayer perspective, the question is when to pay for the cost of restoration – before or after the damage occurs.

PEF Proposal

Q IS PEF PROPOSING AN INCREASE IN THE ANNUAL ACCRUALS FOR ITS STORM RESERVE?

A Yes. PEF is proposing a $10 million increase in annual contributions. This would raise the current annual accrual from $6 million to $16 million per year. This is a significant increase given that PEF currently has a $133 million storm reserve.

Q HAS PEF SOUGHT TO ESTABLISH A TARGET RESERVE BALANCE?

A No. It appears that PEF is proposing to accrue dollars for the storm reserve in perpetuity.

Q SHOULD PEF'S PROPOSED $10 MILLION ANNUAL INCREASE IN STORM RESERVE ACCRUALS BE APPROVED?

A No. PEF has not supported a $10 million increase. Further, since the current $133 million storm reserve is sufficient to cover all but the most severe storms, all contributions to the storm reserve should cease.

Q **WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

A Under the Commission's framework, the storm reserve accrual and reserve balance are designed to provide coverage for some, but not all storms. However, the Hurricane Loss and Reserve Performance Analyses (Study) presented by PEF witness Harris takes into account all manner and strength of storms. (*Direct Testimony of Steven P. Harris,* Exhibit __ (SPH-1)). In other words, it assumes that the storm reserve should be adequate to cover damage from all storms. Thus, the current $133 million reserve balance covers all Category 1 hurricanes and most, but not the most destructive, Category 2 storms. Thus, it is sufficient to cover eight consecutive years in which the expected annual loss (EAL) chargeable to the storm reserve occurs.

Q **WHY IS PEF SEEKING A $10 MILLION INCREASE IN STORM DAMAGE ACCRUALS?**

A The proposed increase is based on the "expected, average annual recoverable storm loss" derived in the Study (*Direct Testimony of Peter Toomey* at 25). Specifically, PEF witness Toomey concludes that the additional $10 million annual accrual will produce a mean reserve balance of $152 million at the end of five years. (*Id.*)

Q **DO THE STUDY AND THE TESTIMONY OF PEF WITNESS HARRIS EXPLICITLY SUPPORT AN INCREASE IN THE ANNUAL CONTRIBUTIONS?**

A No. PEF witness Harris, the sponsor of the Study, stated in his testimony that PEF asked that he review its storm loss exposure and reserve performance and assess the impact of four varying accrual levels on the reserve performance. Those accrual levels are $6 million, $16 million, $25 million and $35 million. Further, Mr. Harris specifically states that his role

> ....was not to recommend an annual level of accrual or target reserve level. Rather, I presented probabilities to PEF regarding reserve performance based on various levels of annual accrual. (*Direct Testimony of Steven P. Harris* at 9).

Q **WHAT TYPE OF STORMS ARE INCLUDED IN THE STUDY PRESENTED BY MR. HARRIS?**

A Mr. Harris quantifies the EAL using a long-term (100 year) analysis of storm damage. His analysis includes all storms, including the most severe storm to affect PEF's service territory, the 1921 Category 3 hurricane that made landfall in Pinellas County. The EAL for all levels of storms is approximately $20 million per year, with a $16.4 million average expected charge to the reserve. (*Id.* at 6). Over the last three years, PEF has charged less than $13 million (in total) to the reserve, as shown in **Exhibit MJM-5**. This equates to a three-year average of $4.3 million.

Q **WHAT IS THE LIKELIHOOD THAT PEF WOULD INCUR DAMAGE IN EXCESS OF THE CURRENT $133 MILLION RESERVE BALANCE?**

A Table 3-1 of Exhibit No. __ (SPH-1) in the Study provides Aggregate Damage

Excedance Probabilities for various damage levels up to and in excess of $310 million. According to the Study, there is a 3.3% probability that there will be damage in any one year that exceeds the current reserve level of $133 million. In other words, a storm inflicting damage in an amount of approximately $130 million is likely to occur once every 33 years.

Q **WHAT RESULTS DOES THE STUDY SHOW FOR CATEGORY 1 AND 2 HURRICANES?**

A The most destructive Category 1 storm would cause damage of slightly less than $50 million (*Id.,* Exhibit No._ (SPH-1) at 19). The damage from the most costly Category 2 storm would cause damage of slightly in excess of $140 million and require an additional $10 million to cover the estimated costs to restore service.

Q **IS IT NECESSARY TO SET THE STORM RESERVE ACCRUAL TO COVER THE COSTS OF ALL TROPICAL STORMS OR HURRICANES REGARDLESS OF THE LEVEL OF SUCH STORM?**

A No. The storm reserve and associated accrual are only part of the framework for recovering storm restoration costs. The Commission has demonstrated its ability and willingness to promptly consider and act upon a utility request to recover storm costs. As such, the storm reserve need not cover all storms. To do so would impose an unnecessary added burden on ratepayers.

Rather, what is needed is a reasonable accrual and a reasonable reserve designed to cover the expected damage from the more common (but not all) storm events. In this instance, PEF is seeking to establish the reserve at a level designed to provide for coverage for all storms damage. Such a "worst case" approach is only necessary if the storm reserve and associated accrual are the only means by which a utility is able to obtain coverage for damages from storms.

Q **HOW ARE RATEPAYERS AFFECTED BY THE PROPOSED $10 MILLION PER YEAR INCREASE IN CONTRIBUTIONS TO THE STORM RESERVE?**

A Ratepayers will see higher rates.

Q **DO RATEPAYERS BENEFIT FROM HIGHER CONTRIBUTIONS TO FUND THE RESERVE?**

A No. As explained above, the current $6 million contribution and the current storm reserve of $133 million are more than sufficient to cover all but the most severe storms. In contrast, the increase will benefit PEF by increasing its cash flow. Finally, the risk of non-recovery for storm damage restoration costs will remain with ratepayers, so that if a catastrophic storm or storms strike PEF's service territory, ratepayers will be surcharged in an amount to permit PEF to recover the costs of service restoration in excess of the storm reserve amount.

Q **DOES PEF EXPLAIN HOW AN INCREASE IN THE ACCRUAL WILL BENEFIT RATEPAYERS?**

A No. The only explanation provided by PEF Witness Harris suggests that the $16 million accrual may provide for rate stability. However, given the current reserve balance and recent history, it is not necessary to raise rates to achieve rate stability.

Q **IS AN INCREASE IN THE RESERVE NECESSARY TO MAINTAIN THE STATUS QUO?**

A No. The current reserve balance is sufficient to cover all Category 1 hurricanes (at current levels, even two such hurricanes in one year), as well as all but the most severe Category 2 hurricanes. In fact, at the EAL chargeable to the reserve each year, the reserve balance is sufficient to provide coverage for eight years. Thus, it is not necessary to continue the current funding level.

Q **WHAT IS THE IMPACT ON THE STORM RESERVE IF ACCRUALS ARE STOPPED?**

A Over time, the level of the reserve will decline. However, absent a direct strike in the most populated portion of PEF's service territory, or the once in every 33-year storm occurrence causing over $130 million in damage, the current reserve balance is sufficient to cover the EAL for the next eight years. If losses remain at the levels experienced over the 2006-2008 period, the current reserve is more than capable of supporting storm recovery for 30 years, without any further ratepayer contributions.

Q **SHOULD THE COMPANY REVISE ITS STORM RESERVE ANALYSIS IN THE NEXT RATE CASE?**

A Yes. Since the present analysis addresses all manner of storms up to and including the most severe and damaging storms, the Commission should require that in any subsequent study presented, alternative levels of storm damage are considered. I am suggesting that any subsequent study should look at the reserve performance taking into account only Category 1 storms and also potentially Category 2 storms. This approach gives recognition to the framework for addressing storm restoration costs – that being that the accrual and reserve balance is designed to cover most but not the most destructive storms.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A The storm reserve accrual should be suspended as of the effective date of any new rates approved in this proceeding. The current reserve balance is sufficient to provide for coverage of the EAL and also provides coverage for all Category 1 storms. A revised study should be submitted when PEF next files a rate increase, or seeks to re-institute the storm reserve accrual and collection that shows what an appropriate reserve target is assuming coverage of most (Category 1 and 2 storms) instead of all level of storms.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

CHAIRMAN CARTER: Staff, you're recognized. Witness Hicks?

MS. FLEMING: Thank you. Yes. Staff would ask that the prefiled testimony of Rhonda L. Hicks be moved into the record as though read.

CHAIRMAN CARTER: Are there any objections? The prefiled testimony of the witness will be inserted into the record as though read.

Any exhibits?

MS. FLEMING: Yes. The exhibits for Ms. Hicks are contained on Page 42 of the staff composite exhibit. They've been identified as Exhibits Numbers 206 and 207.

CHAIRMAN CARTER: Let me turn my page here. Are there any, any objections?

MR. BURNETT: No, sir.

CHAIRMAN CARTER: Without objection, Exhibits 206 and 207 will be entered into the record -- 206 and 207 will be entered into the record without objection.

(Exhibits 206 and 207 marked for identification and admitted into the record.)

Staff, you're recognized. That was for Witness Hicks.

DIRECT TESTIMONY OF RHONDA L. HICKS

Q. Please state your name and address.

A. My name is Rhonda L. Hicks. My address is 2540 Shumard Oak Boulevard; Tallahassee, Florida; 32399-0850.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as Chief of the Bureau of Consumer Assistance in the Division of Service, Safety, and Consumer Assistance.

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

A. I graduated from Florida A&M University in 1986 with a Bachelor of Science degree in Accounting. I have worked for the FPSC for 23 years. I have varied experience in the electric, gas, telephone, and water and wastewater industries. My work experience includes rate cases, cost recovery clauses, depreciation studies, tax, audit, consumer outreach and consumer complaints. I currently work in the Bureau of Consumer Assistance within the Division of Service, Safety, and Consumer Assistance where I manage consumer complaints and inquiries.

Q. What is the function of the Bureau of Consumer Assistance?

A. The bureau's function is to resolve disputes between regulated companies and their customers as quickly, effectively, and inexpensively as possible.

Q. Do all consumers, who have disputes with their regulated company, contact the Bureau of Consumer Assistance?

A. No. Consumers may initially file their complaint with the regulated company and reach resolution without the bureau's intervention. In fact, consumers are encouraged to allow the regulated company the opportunity to resolve the dispute prior to any

Commission involvement.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to advise the Commission of the number of consumer complaints logged against Progress Energy Florida, Inc. (PEF) under Rule 25-22.032, Florida Administrative Code, Consumer Complaints, from July 1, 2007 through June 30, 2009. My testimony will also provide information on the type of complaints logged and those complaints that appear to be rule violations.

Q. What do your records indicate concerning the number of complaints logged against PEF?

A. From July 1, 1007, through June 30, 2009, the FPSC logged 5,611 complaints against PEF. Of those, 4,386 complaints were transferred directly to the company for resolution via the Commission's Transfer-Connect Program.

Q. What have been the most common types of complaints logged against PEF?

A. During the specified time period, approximately 63 percent or 3,559 of the complaints logged with the Commission concerned billing issues, while approximately 37 percent or 2,052 of the complaints involved quality of service issues.

Q. Do you have any exhibits attached to your testimony?

A. Yes. I am sponsoring Exhibits RLH-1 and RLH-2.

Q. Would you explain Exhibit RLH-1?

A. Yes. Exhibit RLH-1 is a summary listing of complaints logged against PEF under Rule 25-22.032, Florida Administrative Code. The complaints, received July 1, 2007, through June 30, 2009, were captured in the Commission's Consumer Activity Tracking System (CATS). The summary groups the complaints by Close Type and within each Close Type, the complaints are segregated by Pre-Close Type. The first grouping is Pre-Close types that are still pending. The remaining groupings are categorized by Close Type codes such as EB-01, EB-02, EB-12, etc.

Q. What is a Pre-Close Type?

A. A Pre-Close Type is an internal categorization code that is applied to each complaint upon receipt. A complaint is assigned a Pre-Close Type based solely on the initial information provided by the consumer.

Q. What is a Close Type?

A. A Close Type is also an internal categorization code. It is assigned to each complaint once staff completes its investigation and a proposed resolution is provided to the consumer. In some instances, the Pre-Close Type will differ from the Close Type because staff's investigation reveals facts that were not available upon receipt of the complaint.

Q. A great majority of complaints were resolved as Close Type GI-02, Courtesy Call/Warm Transfer. Can you explain this Close-Type?

A. Yes. PEF participates in the Commission's Transfer-Connect (Warm Transfer) System. This system allows the Commission to directly transfer a customer to the company's customer service personnel. Once the call is transferred to PEF, it provides the customer with a proposed resolution. Customers who are not satisfied with the company's proposed resolution have the option of recontacting the Commission. While the Commission is able to assign a Pre-Close Type to each of the complaints in this category, a specific Close-Type is not assigned because the proposed resolution is provided by Progress Energy Florida. Consequently, the assigned Close-Type allows staff to monitor the number of complaints resolved via the Commission's Transfer-Connect System.

Q. How many of the complaints summarized on your exhibit has staff determined may be a violation of Commission rules?

A. Of PEF's 5,611 complaints, staff determined that 17 appear to be violations of

Commission rules. The 17 complaints that appear to be violations of Commission rules are summarized on Exhibit RLH-2.

Q. Would you explain Exhibit RLH-2?

A. Exhibit RLH-2 is a summary chart of the 17 complaints that appear to violations of Commission rules. The chart provides the complaint number, close type and the nature of each apparent rule violation.

R. How does the Bureau of Consumer Assistance handle apparent rule violations?

A. Apparent rule violations are closely monitored by bureau management. If an apparent violation is habitual or if it appears that an apparent violation could impact the entire customer base, technical staff is notified and forwarded a copy of the complaint(s). Following its review, technical staff determines if Commission action is needed.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN CARTER: You're recognized for Witness Stephens.

MS. FLEMING: Staff would ask that the prefiled direct testimony of Jocelyn Stephens be moved into the record as though read.

CHAIRMAN CARTER: And that's through stipulation by agreement of the parties; is that correct?

MR. BURNETT: Yes, sir.

CHAIRMAN CARTER: The prefiled testimony of the witness will be inserted into the record as though read.

Staff, exhibits?

MS. FLEMING: Jocelyn Stephens has one exhibit, which is Exhibit Number 208, and we would ask that that be moved into the record.

CHAIRMAN CARTER: Are there any objections?

MR. BURNETT: No, sir.

CHAIRMAN CARTER: Without objection, show it done. Exhibit Number 208 entered into the record.

(Exhibit 208 marked for identification and admitted into the record.)

MS. FLEMING: And finally, Commissioners, with respect to Jocelyn Stephens, at this time staff is handing out Progress's response to the PSC's rate case audit findings. I have conferred with all the parties. All the parties have stipulated to this, and we need a hearing exhibit number, please.

CHAIRMAN CARTER: 290. 290. Short title?

MS. FLEMING: Audit Findings.

CHAIRMAN CARTER: Excellent. Give me one second here. My writing got cold. I couldn't read it.

Are there any objections from the parties?

MR. BURNETT: No, sir.

CHAIRMAN CARTER: Without objection, Exhibit Number 290 will be entered into evidence.

(Exhibit 290 marked for identification and admitted into the record.)

Thank you, staff. Anything further?

MS. FLEMING: We have nothing further. Thank you.

DIRECT TESTIMONY OF JOCELYN Y. STEPHENS

Q. Please state your name and business address.

A. My name is Jocelyn Stephens and my business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida, 33609.

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

A. I am employed by the Florida Public Service Commission as a Professional Accountant Specialist in the Division of Regulatory Compliance.

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

A. I have been employed by the Florida Public Service Commission since January 1977.

Q. Briefly review your educational and professional background.

A. In 1972, I received a Bachelor of Science degree from Florida State University with a major in accounting. I am also a Certified Public Accountant licensed in the State of Florida since May 1989.

Q. Please describe your current responsibilities.

A. Currently, I am a Professional Accountant Specialist with the responsibilities of planning and directing the most complex investigative audits. Some of my past audits include cross-subsidization issues, anti-competitive behavior, and predatory pricing. I am also responsible for creating audit work programs to meet a specific audit purpose and integrating EDP applications into these programs.

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

A. Yes. I testified in the Florida Cities Water Co., (South Fort Myers) transfer of certificate, Docket No. 910447-SU; the fuel and purchased power cost recovery clause proceedings, Docket No. 030001-EI; the petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc., Docket No. 041272-EI; and the petition for rate increase by Peoples Gas System, Docket No. 080318-GU.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Progress Energy Florida, Inc. (PEF or utility) which addresses the utility's petition for a rate increase. This audit report is filed with my testimony and is identified as Exhibit JYS-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, I was the audit manager in charge of the audit. The audit report was prepared by me or under my direction.

Q. Please describe the work performed in this audit.

A. **<u>Rate Base</u>:**

We reconciled the individual component rate base balances listed below to the utility's general ledger as of December 31, 2008. We determined that the utility made adjustments to its rate base balances that were properly calculated and consistent with prior approved Commission rate case adjustments. We reviewed and tested the allocation methodology used by Progress Energy Service Company (Service) and Progress Energy Carolina (PEC) to charge costs to PEF. We reviewed and analyzed the costs recorded on the books of Service and PEC.

We scheduled and analyzed plant additions, adjustments/reclassifications and retirements for the period January 2005 through December 2008 using the Federal Energy Regulatory Commission Form 1 Annual Reports (Form 1). We reconciled annual balances from the Form 1to the general ledger. We requested and received a reconciliation of the Form 1 balances to the Power Plant System. We selected plant account activity for further analysis and verification using third party documentation. We verified the general ledger balance for Plant Held for Future Use (PHFU) at December 31, 2008, and determined that the utility removed PHFU in its entirety from rate base consideration. On a test basis, we recalculated the 13-month average balance of plant accounts. We reconciled Construction Work in Progress (CWIP) recorded in the MFRs with general ledger balances and reviewed a reconciliation of CWIP balances as of December 31, 2008, with the balances recorded in the Power Plant System. We selected a sample of open work orders and reconciling entries charged to CWIP and recorded in the Power Plant System as of December 31, 2008, verified that the work order pertained to an authorized and approved construction project, and reviewed supporting source documents for authenticity. We determined that Allowance for Funds Used During Construction (AFUDC) was not charged to any work orders included in CWIP and we recalculated the 13-month average balances for CWIP. On a sample basis, we verified that accumulated depreciation and amortization as of December 31, 2008, were properly recorded, using rates in the depreciation study approved by the Commission for the period January 1, 2006, through December 31, 2008.

We reviewed the Commission order from PEF's prior rate case and determined the treatment of working capital items. We determined that the utility's adjustments for the current working capital were consistent with the adjustments in PEF's prior rate case. We reviewed a sample of the transactions recorded in clearing accounts, stores expenses, prepayments, deferred debits and credits, and accrued liabilities to determine if they were proper, utility-related in nature, and that expenses were not overstated. We reviewed transactions in Materials and Supplies and Other Accounts Receivable to determine if non-utility items were posted. We determined that no interest bearing accounts were included in the calculation of working capital. We recalculated the 13-month average balances for all accounts included in the working capital computation.

Net Operating Income:

We reconciled the individual component net operating income (NOI) balances to the utility's general ledger as of December 31, 2008. We verified utility adjustments to NOI balances and reconciled the adjustments to the utility's other Commission filings during the test year or to prior orders that required the specific adjustment. We reviewed and tested the allocation methodology used by Service and PEC to charge costs to PEF. We reviewed and analyzed the costs recorded on the Income Statement of Service and PEC.

We verified that adjustments to NOI were accurately calculated, agreed with amounts in the general ledger, or were included in clause filings. We reconciled utility revenues for the 12-month period ended December 31, 2008, to the general ledger and determined that revenues for all recovery clauses were removed in the proper amounts from the historical base year.

We verified the calculation of unbilled revenues. We tested customer bills to determine that customers were charged rates in accordance with the Commission-approved tariff sheets. We verified, based on a sample of utility transactions for select Operation and Maintenance (O&M) expense accounts, that utility O&M expense balances are adequately supported by source documentation, prudent, utility-related in nature and do not include non-utility items. We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses, and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed. We reviewed intercompany allocations and charges between affiliated companies and non-utility operations to determine if expenses were properly allocated. We verified, based on a sample of depreciation expense accruals, that the company is using correct depreciation rates as authorized in Commission Order No. PSC-05-0945-S-EI. We verified, based on a sample of utility transactions for select Taxes Other than Income Tax (TOTI) accounts, that utility TOTI expense balances are adequately supported by source documentation.

Capital Structure:

We reconciled the individual component capital structure balances to the utility's general ledger as of December 31, 2008. We verified that non-utility assets supported by the utility's capital structure were removed and that the capital structure adjustments reconciled with the rate base adjustments in the filing. We recalculated the 13-month average balances and the weighted average cost of capital for the utility's historical test year capital structure.

We verified that adjustments to the capital structure were accurately calculated and reconciled the amounts to the general ledger. We traced equity balances to the general ledger. We traced the long-term debt and reacquired debt acquisition cost balances to the original documents and verified the terms, conditions, redemption provisions and interest rates for each bond or note payable. We determined Discount on Debt and Debt Issue Costs and recalculated the amortization of Discount and Debt Issue Cost and Interest Expense. On a sample basis, we traced Debt Issue Costs to source documentation. We recalculated the weighted average cost of long-term debt. We traced the short-term debt balances to supporting documents, verified interest rates, and traced the computation of the average cost of short-term debt to utility documentation.

We reconciled the customer deposit balances to the general ledger and verified that customer deposits are charged in accordance with the tariff rates. We verified that interest on customer deposits is credited to customer bills at the Commission approved rate as designated in the tariff. We recalculated interest expense on Customer Deposits.

We reconciled the deferred tax balances to the general ledger. We reconciled net Investment Tax Credits to the general ledger. We reconciled the ending balance of Investment Tax Credits in the prior audit to the beginning balance in the current audit and verified the calculation of the annual amortization of investment tax credits.

Q. Please review the audit findings in this audit report, JYS-1, which addresses the 2008 actual filings for the PEF Rate Case.

A. We found items which were incorrect in the historical test year. The audit staff only audited the 2008 historical test year per the audit services request. Since rates in this case will be set based on a 2010 forecasted test year, additional work will need to be performed to determine the effect, if any, of the findings on the 2010 test year.

Audit Finding No. 1

Charges for "Order of Taking" on land easements were incorrectly recorded in Plant in Service accounts 355 and 356, Poles and Fixtures and Overhead Conductors and Devices rather than in the account Land and Land Rights.

Audit Finding No. 2

Staff found several errors in the prorata adjustments to the capital structure. However, correction of the errors did not result in a change in the weighted cost of capital.

Audit Finding No. 3

A correction to the income tax interest synchronization adjustment was not included by PEF in the utility's filing. Based upon additional information provided by

PEF after the issuance of the audit report, the correct effect of Audit Finding No. 3 on the filing for 2008 is a decrease to NOI of $1,295,000. This has no effect on the filing for 2009 or 2010. Audit Finding No. 3 was revised on August 24, 2009. Revised Audit Finding No. 3 is included in Exhibit JYS-1.

Audit Finding No. 4

Non-utility related expenses totaling $267,486 were included in the filing.

Audit Finding No. 5

This audit finding provides information concerning amounts billed by Progress Energy Service Company to PEF.

Audit Finding No. 6

This audit finding provides information concerning amounts billed by Progress Energy Carolina to PEF.

Audit Finding No. 7

This audit finding provides information concerning payroll expense.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN CARTER: Okay. Let's do this. Before we call for rebuttal, let's give the court reporter about five minutes, and then we'll be ready to go. Because I think Dr. Vander Weide -- and forgive me if I'm messing up your name -- he's already been sworn. So we'll just, we'll kick off in about -- let's take ten, everybody.

(Recess taken.)

(Transcript continues in sequence with Volume 17.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

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

DATED THIS 30th day of September, 2009.

Linda Boles
LINDA BOLES, RPR, CRR
FPSC Official Commission Reporter
(850) 413-6734