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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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In the Matter of:

DOCKET NO. 120015-EI

PETITION FOR INCREASE IN RATES
BY FLORIDA POWER & LIGHT COMPANY.
_______________________________/

VOLUME 22

Pages 3177 through 3471

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING:
CHAIRMAN RONALD A. BRISE
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, August 28, 2012

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

REPORTED BY: LAURA MOUNTAIN, RPR
Wilkinson & Associates
(850) 224-0127

APPEARANCES: (As heretofore noted.)

DOCUMENT NUMBER-DATE
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# I N D E X

## WITNESSES

EXHIBITS

P R O C E E D I N G S

(The transcript follows in sequence from Volume 21.)

CHAIRMAN BRISE: All right, we're going to go ahead and reconvene at this time. I think there is a preliminary matter that we have to deal with. It's prefiled testimony that I'm not sure that -- from my understanding, the court reporter wasn't sure we put that into the record, and that was for Mr. --

MR. YOUNG: Baudino.

CHAIRMAN BRISE: Baudino. So without any objections we will move Mr. Baudino's prefiled testimony into the record, okay? All right.

MR. YOUNG: The exhibits have already been moved. The exhibits have already been moved.

CHAIRMAN BRISE: Right. So we were clear on the record that the exhibits are in. That was the only thing that there was a question about?

MR. YOUNG: Yes, sir.

CHAIRMAN BRISE: Perfect. At this time I'm going to turn the gavel over to Commissioner Brown.

COMMISSIONER BROWN: Thank you. South Florida Hospitals, I think you have Mr. Kollen on the stand.

MR. WISEMAN: Thank you.

Thereupon,

LANE KOLLEN

was called as a witness on behalf of South Florida Hospital and Healthcare Association, and having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WISEMAN:

Q Mr. Kollen, could you state your full name and business address for the record, please.

A Yes, my name is Lane Kollen. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q And are you the same Mr. Kollen who caused 57 pages of testimony to be prefiled in this proceeding?

A Yes.

Q And are you also the same Mr. Kollen who caused an errata to be filed to that testimony on July 9th, 2012?

A Yes.

Q And do you have any corrections to your prefiled testimony?

A I have one additional correction. On page 46 of my testimony there is a missing table that would normally follow, or the narrative preceding line 18 suggests that there is a table that is following. It does not -- did not end up in the text. So I can change the wording or we can just recognize that the table isn't there.

It is repeated in the Exhibit LK-25. I think at this point I'd rather just leave the reference in to Exhibit LK-25 and not change the wording and just notify people that the table is in the exhibit.

COMMISSIONER BROWN: Mr. Wiseman, is that acceptable?

MR. WISEMAN: That's acceptable if it's acceptable to the Commission.

COMMISSIONER BROWN: Yes.

BY MR. WISEMAN:

Q And with that you have no further changes to your testimony?

A That's correct, no further changes.

Q And also, did you submit 29 exhibits with your prefiled testimony that have been marked for identification as Exhibits 320 through 348?

A Yes.

Q And do you have any changes to those exhibits?

A No.

MR. WISEMAN: Ms. Chair, with that I would ask that Mr. Kollen's testimony be inserted into the record as read.

COMMISSIONER BROWN: Seeing no objections, I would enter in Mr. Kollen's prefiled direct testimony into the record as though read.

**BEFORE THE FLORIDA**
**PUBLIC SERVICE COMMISSION**

**IN RE:**

**PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY ) DOCKET NO. 120015-EI**

## DIRECT TESTIMONY OF LANE KOLLEN

## I. QUALIFICATIONS AND SUMMARY

**Qualifications**

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

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

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

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with Kennedy and Associates.

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

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified

Public Accountant, with a practice license, a Certified Management Accountant, and a Chartered Global Management Accountant.

I have been an active participant in the utility industry for more than thirty years, both as a consultant and as an employee. Since 1986, I have been a consultant with Kennedy and Associates, providing services to consumers of utility services and state and local government agencies in the areas of utility planning, ratemaking, accounting, taxes, financial reporting, financing and management decision-making. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies in the areas of planning, financial reporting, financing, ratemaking and management decision-making. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions providing services in the areas of planning, accounting, taxes, auditing, and financial and statistical reporting.

I have appeared as an expert witness on utility planning, ratemaking, accounting, reporting, financing, and tax issues before state and federal regulatory commissions and courts on more than two hundred occasions. In many of those proceedings, I have represented state and local ratemaking agencies or their Staffs, including the Louisiana Public Service Commission, Georgia Public Service Commission and various groups of Cities with original rate jurisdiction in Texas. I also have appeared before the Florida Public Service Commission ("Commission") in numerous proceedings, including the three most recent Florida Power & Light Company ("FPL" or "Company") base rate proceedings in Docket Nos. 080677-EI (2009), 050045-EI (2005) and 001148-EI (2002). I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

**Summary**

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am offering testimony on behalf of the South Florida Hospital and Healthcare Association ("SFHHA"), whose members take electric service on the FPL system.

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

A. The purpose of my testimony is to address the Company's proposed base rate increase and the effects on various recovery clauses, to summarize the effects of the SFHHA recommendations on the Company's claimed revenue requirements, and to address and make recommendations on specific issues that affect the Company's claimed revenue requirements.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I recommend that the Commission increase the Company's base rates on January 1, 2013 by no more than $42.784 million, a reduction of at least $473.737 million from the increase of $516.521 million requested by the Company in this proceeding. I also recommend that the Commission increase the Company's base rates by no more than $147.473 million for the Canaveral Modernization step increase on or about June 1, 2013, a reduction of at least $26.378 million from the step increase of $173.851 million requested by the Company in this proceeding. These recommendations include the effects of SFHHA witness Mr. Richard

Baudino's recommended return on common equity. I summarize the effects of the SFHHA recommended adjustments separately for the two increases on the following tables. In addition, I address the substance of each of these adjustments in the following sections of my testimony, except for the return on common equity, although I quantify the effect of Mr. Baudino's recommendation.

**FLORIDA POWER AND LIGHT**
**REVENUE REQUIREMENT MINIMUM REDUCTIONS RECOMMENDED BY SFHHA**
**DOCKET NO. 120015-EI**
**TEST YEAR ENDING DECEMBER 31, 2013**
**($ MILLIONS)**

| | Amount |
|---|---|
| **Base Rate Change per FP&L Filing** | **$ 516.521** |
| **Rate Base Adjustments:** | |
| Modify Cash Working Capital from Balance Sheet to Lead/Lag | (16.177) |
| Modify Nuclear Maintenance Reserve from Prepaid to Postpaid | 1.763 |
| Eliminate Unamortized Rate Case Expense | (0.500) |
| Reduce CWIP in Rate Base | (26.052) |
| **Operating Income Adjustments:** | |
| Normalize Nuclear Maintenance Outage Expense | (15.183) |
| Modify Nuclear Maintenance Expense from Prepaid to Postpaid | (37.402) |
| Reduce Vegetation Management Expense | (9.447) |
| Reflect Projected Net AMI Deployment Savings | (23.731) |
| **Capital Structure and Rate of Return Adjustments:** | |
| Adjust ADIT for Rate Base Adjustments | (0.396) |
| Set Return on Equity at 9.0% | (387.578) |
| **Total Minimum SFHHA Recommended Adjustments** | **($473.737)** |
| **Maximum SFHHA Recommendation for Base Rate Change** | **$42.784** |

**FLORIDA POWER AND LIGHT**
**REVENUE REQUIREMENT MINIMUM REDUCTIONS RECOMMENDED BY SFHHA**
**CANAVERAL STEP INCREASE**
**DOCKET NO. 120015-EI**
**TEST YEAR ENDING MAY 31, 2014**
**($ MILLIONS)**

| | Amount |
|---|---|
| **Canaveral Step Increase per FP&L Filing** | $ 173.851 |
| **Rate Base Adjustments:** | |
| Reflect Additional ADIT - Bonus Depreciation | (6.052) |
| **Capital Structure and Rate of Return Adjustments:** | |
| Set Common Equity and Long-Term Debt Ratios to Same as Base Rev Req | (1.451) |
| Set Return on Equity at 9.0% | (18.876) |
| **Total Minimum SFHHA Recommended Adjustments** | **($26.378)** |
| **Maximum SFHHA Recommendation for Canaveral Step Increase** | **$147.473** |

In addition to the adjustments on the preceding tables, the SFHHA may support adjustments proposed by other parties at hearing and on brief.

Finally, the Commission should recognize that the cost of capital adopted in this proceeding, including the return on equity, affects the Company's clause recoveries that include a return on rate base investment, except for the nuclear cost recovery. The primary effect is on the Company's environmental cost recovery, which presently reflects a 10.0% return on equity. Thus, any return on equity greater than 10.0% will result in an increase in the environmental cost recovery *in addition* to the increases the Company has requested in this proceeding. Any return on equity less than 10.0% will result in a reduction to the environmental cost recovery and will offset any base rate increases authorized in this proceeding. The Company's request for an 11.50% return on equity will increase the environmental revenue requirement by $14.598 million in 2013 in addition to the base rate increase sought in this proceeding. The SFHHA recommendation for a 9.0% return on equity not only will eliminate the increase in the environmental revenue requirement due to the Company's requested increase in the return on common equity, but also will reduce the environmental clause recovery by $9.732 million in 2013, for a combined reduction (compared to the Company's request) of $24.329 million.

The remainder of my testimony is structured to follow the sequence of the adjustments listed on the preceding tables.

## II. RATE BASE ISSUES

### A. Cash Working Capital

**Q. PLEASE GENERALLY DESCRIBE THE COMPANY'S WORKING CAPITAL CALCULATION.**

A. The Company calculated working capital using a balance sheet approach as detailed on Schedule B-17 for the test year and the prior year. In general, the Company included the 13 month average of all balance sheet asset and liability accounts that were not included in other components of rate base, such as plant-in-service, or in the capital structure, such as accumulated deferred income taxes ("ADIT"), although it made certain adjustments to remove some or all of the amounts in certain of the asset and liability accounts.

The revenue requirement effect of the working capital included in rate base or any adjustments to the amount included in rate base can be determined by multiplying the amount included in rate base or the amount of the adjustment times the Company's requested grossed-up rate of return. The effects on the revenue requirement of changes to the Company's requested rate of return are quantified using the rate base after all adjustments.

**Q. DOES THE BALANCE SHEET APPROACH PROVIDE AN ACCURATE MEASUREMENT OF THE COMPANY'S INVESTMENT IN *CASH WORKING CAPITAL*, A SUBSET OF THE WORKING CAPITAL CALCULATION?**

A. No. The balance sheet approach is outdated and fails to accurately quantify the utility's *cash working capital* ("CWC") investment in light of sophisticated cash management techniques, including electronic funds transfer, designed to minimize that investment and the related financing requirements. The lead/lag approach is a more sophisticated approach used in many jurisdictions to more accurately quantify the CWC investment. It does so by tracking and measuring the timing of cash flows related to revenues and expenses. In contrast to the lead/lag approach, the balance sheet approach (implemented before electronic funds transfers were as prevalent as they are today) limits the measurement of the cash working capital investment to a one day end of month "snapshot" of the amounts in certain balance sheet accounts (receivables and payables). Thus, the lead/lag approach more accurately measures the rate base investment, whether negative or positive, resulting from the actual time-weighted delays in the receipt of cash resulting from sales compared to the delays in the disbursement of cash resulting from expenses for payroll, fuel expense, other operation and maintenance ("O&M") expenses, and other expenses.

The lead/lag approach measures the average number of days from the date the utility provides service until it converts the customer receivables for the service into cash. The lead/lag approach also measures the average number of days from the date the utility obtains services from employees or vendors or incurs other expenses until the date the payables are converted to cash disbursements. The measurements of the lead/lag days are made based on a study of actual revenues and expenses for a historic period and the results are applied to the revenues and expenses in the test year. Noncash expenses, such as depreciation and deferred tax expense, are excluded from the calculations. The annual revenues and expenses for the test year are converted to daily amounts, then weighted by the appropriate lead/lag days, and then summed to determine that amount of cash working capital that should be included in rate base.

**Q. WHAT IS THE COMPANY'S CLAIMED BASIS FOR USING THE BALANCE SHEET METHOD?**

A. The Company claims that it used the balance sheet approach as a matter of precedent, not as a matter of ratemaking principle or on the basis that the balance sheet approach is superior to the lead/lag approach, according to its response to SFHHA Interrogatory 209. I have attached a copy of the Company's response to SFHHA Interrogatory 209 as my Exhibit___(LK-2).

**Q. IS THE BALANCE SHEET APPROACH SUPERIOR TO THE LEAD/LAG APPROACH?**

A. No. The balance sheet approach is very imprecise and could result in a significant overstatement of the cash working capital requirement. In my experience, the balance sheet approach tends to overstate the investment in receivables compared to payables for the same service period when the results of the balance sheet approach are compared side by side with the results of the lead/lag approach. That is because the balance sheet approach fails to consider the time weighted leads and lags that are specifically measured in the lead/lag approach. Instead of measuring and time weighting the leads and lags, the balance sheet approach assumes that the relationship between revenues and expenses is the same throughout the month as it is at the end of each month. The balance sheet approach assumes this relationship even though in fact the relationships fluctuate significantly on a daily basis depending upon the pattern of cash receipts and disbursements throughout the month.

Consider the following example. Assume that the utility maintains an average customer accounts receivable balance of $300 million each day, including the last day of the month. Assume also that the utility incurs expenses of $300 million during the month at the rate of $10 million per day and then pays all of its bills on the last day of the month so that its accounts payable equal $0 on that last day. Throughout the month, the accounts payable were $150 million on an average daily basis. If the cash working capital using the balance sheet approach is calculated at the end of the month, in the same manner that the Company calculated it, then the rate base amount would be $300 million. However, in this example, the more precise and accurate measurement using the average daily balance would result in a cash working capital of $150 million.

Consider another example. Assume the same facts as in the first example, but assume that the utility's receivables increase significantly in the last week of the month, from a daily average of $250 million in the first three weeks to $350 million in the last week. If the cash working capital using the balance sheet approach is calculated at the end of the month, in the same manner that the Company calculated it, then the rate base amount would be $350 million. However, the more precise and accurate measurement using the average daily balance would result in a cash working capital of $125 million (($250 million x 3 weeks + $350 million)/4 weeks to determine average daily balance of accounts receivable less $150 million accounts payable).

The lead/lag approach solves the inherently imprecise and inaccurate result of the balance sheet approach, or more importantly, the result of the balance sheet approach using end of the month amounts as the Company has done.

**Q. WHICH BALANCE SHEET ACCOUNTS WOULD BE REMOVED FROM THE WORKING CAPITAL CALCULATION IF THE LEAD/LAG APPROACH IS USED TO CALCULATE THE *CASH* WORKING CAPITAL?**

A. On the asset side of the balance sheet, all of the customer receivables and accrued utility revenues (unbilled revenues) would be removed because the average delay from the date of service until cash is received is directly measured in the cash working capital calculation using the lead/lag approach. Consequently, all of the amounts in account 142 Customer Accounts Receivable and in account 173 Accrued Utility Revenues as shown on Schedule B-17 would be removed. In addition, the amounts in account 165 Prepayments would be removed and the related expense lead/lag included in the cash working capital calculation using the lead/lag approach.

On the liability side of the balance sheet, all of the various accounts payable would be removed because the average delay from the date service was received until the cash is disbursed is directly measured in the cash working capital calculation using the lead/lag approach. Consequently, all of the amounts in account 232 Accounts Payable (net of any construction related accounts payable), account 234 Accounts Payable to Associated Companies, account 236 Taxes Accrued (Payable), and account 237 Interest Accrued (Payable).

Q. **HAS THE COMPANY PREPARED A CASH WORKING CAPITAL STUDY USING THE LEAD/LAG APPROACH?**

A. No. The Company claims that it has not prepared a cash working capital study using the lead/lag approach and refused to perform one, according to its response to SFHHA Interrogatory 210. It also could not or would not provide the lead and lag days for revenues and expenses, apparently on the basis that it hasn't prepared a lead/lag cash working capital study, according to its response to SFHHA Interrogatory 211. Finally, in response to a request for a description of its cash budgeting process and a copy of its most recent cash budgets, including the assumptions and data used for the prior year and the test year, the Company claims that it does not prepare cash budgets, according to its responses to SFHHA 212 and 213. I have attached a copy of the Company's responses to SFHHA Interrogatory 210 as my Exhibit___(LK-3), Interrogatory 211 as my

Exhibit___(LK-4), Interrogatory 212 as my Exhibit___(LK-5), and Interrogatory 213 as my Exhibit___(LK-6).

Thus, the Company failed to provide its cash budgets and failed to provide the data necessary for any other party to perform or apply a lead/lag approach to develop the cash working capital using the lead/lag approach.

**Q. IS THE COMPANY'S CLAIM THAT IT DOES NOT PREPARE CASH BUDGETS CONSISTENT WITH ITS USE OF PROJECTED INFORMATION FOR THE PRIOR YEAR AND THE TEST YEAR?**

A. No. The Company necessarily had to prepare a cash budget in order to project the prior year and the test year capitalization reflected on Schedule D in its filing. In the absence of a cash budget, the Company could not have developed the projections of the internal cash flows and the resulting financing in the prior year or the test year that were necessary for the Company to determine the monthly capitalization amounts used in the cost of capital. In addition, utilities such as FP&L use sophisticated cash management techniques that require detailed projections of cash flows.

**Q. SHOULD THE COMMISSION SIMPLY ACCEPT THE COMPANY'S BALANCE SHEET APPROACH AS A MATTER OF PRECEDENT AND REWARD THE COMPANY'S FAILURE TO PROVIDE ANY INFORMATION RELATED TO THE LEADS AND LAGS ON REVENUES AND EXPENSES?**

A. No. The Commission should reject the balance sheet approach in this proceeding, and adopt a proxy for the results of the lead/lag approach in this proceeding. In addition, the Commission should direct the Company to quantify the cash working capital requirement in its next base rate case using the lead/lag approach and to provide the study and workpapers used to develop the lead/lag days.

**Q. SHOULD THE POTENTIAL COST OF PERFORMING A LEAD/LAG STUDY DISSUADE THE COMMISSION FROM ADOPTING YOUR RECOMMENDATION?**

A. No. The cost of performing a lead/lag study is not significant compared to the Company's revenue requirement, or more specifically, to the revenue requirement resulting from the cash working capital rate base investment. There would be no incremental cost if the Company chose to perform the study itself. Alternatively, there would be an incremental cost if the Company retained an outside expert to perform the study, but it would be insignificant when weighed against the millions of dollars in savings from using the more precise and accurate lead/lag approach.

**Q. WHAT AMOUNT SHOULD THE COMMISSION USE FOR THE CASH WORKING CAPITAL SUBSET OF WORKING CAPITAL IN RATE BASE?**

A. I recommend that the Commission set the cash working capital at $0 as a proxy for the results of the lead/lag approach in the absence of a properly performed cash working capital calculation using that approach. This proxy likely overstates the cash working capital that would result from a properly performed study. In my experience, such studies frequently result in substantially negative cash working capital rate base amounts, a result that is consistent with the sophisticated cash management techniques used by utilities today to minimize their investments in cash working capital.

This recommendation requires that certain of the balance sheet amounts reflected in the Company's working capital be set to $0 and results in a net reduction in the Company's working capital of $156.284 million on a jurisdictional basis. The components of the cash working capital by balance sheet account are detailed on my Exhibit___(LK-7).

**Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION ON THE COMPANY'S REVENUE REQUIREMENT?**

A. The effect is a reduction of $16.177 million ($156.284 million times the Company's proposed grossed-up rate of return of 10.35%).

**B. <u>Accrued Utility Revenues</u>**

**Q. IF THE COMMISSION DOES NOT ADOPT YOUR RECOMMENDATION TO CALCULATE THE CASH WORKING CAPITAL USING THE LEAD/LAG APPROACH, IS THERE ANOTHER PROBLEM WITH THE COMPANY'S WORKING CAPITAL CALCULATION?**

A. Yes. The Company improperly included the amount in account 173 Accrued Utility Revenues (unbilled revenues) in working capital. The amount in this account consists of the unbilled revenues related only to the Company's base tariffs. It does not reflect the unbilled revenues for its clause revenues, according to its response to SFHHA Interrogatories 198 and 199. These unbilled revenues represent the estimated revenues that will be billed for service that was provided during the month, but that were not yet billed at the end of the month. Each month, the unbilled revenues for the prior month are reversed because the prior month's unbilled revenues are billed in the current month and then a new estimate for the current month is recorded. I have replicated the Company's responses to SFHHA Interrogatories 198 and 199 as my Exhibit___(LK-8).

**Q. IS THERE A CARRYING COST ON UNBILLED REVENUES THAT THE COMPANY ACTUALLY INCURS AND SHOULD RECOVER?**

A. No. The unbilled revenues represent an estimate of revenues that were earned during the month, but that were not yet billed. The unbilled revenues are an accounting placeholder for a future receivable, but do not represent a cost that the Company must finance at the end of each month. There are no carrying costs on the unbilled revenues for several reasons. First, the Company did not incur incremental costs to earn these estimated revenues. That is because the unbilled revenues recognized by the Company are for base rates only. The unbilled revenues do not include revenues for recovery of the variable costs that are recovered through clauses, such as the fuel adjustment clause, according to the Company's response to SFHHA Interrogatory 199. If the Company does not accrue unbilled revenues for fuel clause recovery revenues, then it also does not accrue accounts payable for the related fuel expense and there is no incremental amount in the accounts payable account to offset the nonfuel unbilled revenues.

Second, the billed revenues actually provide contemporaneous recovery of the Company's fixed costs each month that do not vary based on sales from month to month. These costs include the return on the Company's rate base investment, depreciation expense, non-fuel O&M expense, and other operating expenses. This is particularly true when the revenue requirement is based on a projected test year that corresponds to a calendar year and not to a lagged test year that corresponds to the Company's unbilled service periods.

**Q. IF THE COMMISSION DOES NOT ADOPT YOUR RECOMMENDATION TO CALCULATE THE CASH WORKING CAPITAL USING THE LEAD/LAG APPROACH, THEN WHAT IS YOUR ALTERNATIVE RECOMMENDATION?**

A. Then I recommend that the Commission remove the accrued revenues from the working capital in rate base. If the Commission adopts my recommendation to calculate the cash working capital using the lead/lag approach, the issue of the accrued revenues is moot because this balance sheet account will be excluded from rate base and the revenue lag is measured from the midpoint of the service period until the date the customer receivable is converted into cash.

**Q. WHAT IS THE EFFECT OF YOUR ALTERNATIVE RECOMMENDATION?**

A. The effect is to reduce the Company's revenue requirement by $17.379 million. I computed this amount by multiplying the $167.889 million jurisdictional amount of accrued utility revenues shown on Schedule B-17 times the Company's proposed grossed-up rate of return of 10.35%.

**C. Nuclear Maintenance Reserve Regulatory Liability**

Q. HAVE YOU ADJUSTED THIS REGULATORY LIABILITY IN CONJUNCTION WITH YOUR RECOMMENDATIONS TO MODIFY THE NUCLEAR MAINTENANCE OUTAGE ACCRUAL FROM A PREPAID TO A POSTPAID RESERVE ACCRUAL AND TO AMORTIZE THE REGULATORY LIABILITY OVER THREE YEARS?

A. Yes. I describe this issue and the effects of my recommendation in greater detail in the Operating Income Issues section of my testimony. The computations of these adjustments are detailed in my Exhibit___(LK-9).

**D. Nuclear Maintenance Reserve Regulatory Asset**

Q. HAVE YOU INCLUDED THE EFFECT OF THE REGULATORY ASSET FOR DEFERRED OUTAGE EXPENSES IN CONJUNCTION WITH YOUR RECOMMENDATION TO MODIFY THE NUCLEAR MAINTENANCE OUTAGE ACCRUAL FROM A PREPAID TO A POSTPAID RESERVE ACCRUAL?

A. Yes. I describe this issue and the effects of my recommendation in greater detail in the Operating Income Issues section of my testimony. The computations of these adjustments are detailed in my Exhibit___(LK-9).

**E. Unamortized Rate Case Expense**

Q. DID THE COMPANY INCLUDE AN ESTIMATE OF THE RATE CASE EXPENSES FOR THIS PROCEEDING IN WORKING CAPITAL?

A. Yes. The Company included $4.826 million in working capital as shown on Schedule B-2 page 4 line 27 for the estimated rate case expenses in this proceeding. The Company also removed $6.050 million in working capital from its balance sheet as shown on Schedule B-2 page 3 line 12. The amount removed was comprised of the remaining amount from its prior rate case of $0.535 million and another $5.515 million for this proceeding. The amount that it included in working capital is less than the amount that it removed because it reflects the 13 month average effect of its request for a four year amortization ($5.515 million less $5.515 million divided by four years divided by 2 to approximate the 13 month average).

**Q. SHOULD THE COMMISSION ALLOW UNAMORTIZED RATE CASE EXPENSE IN RATE BASE?**

A. No. First, the Commission historically has not allowed unamortized rate case expenses in rate base. The Commission rejected a similar request in the Company's last base rate proceeding and recently rejected Gulf Power Company's similar request in Docket No. 110138-EI. [Order No. PSC-12-0179-FOF-EI].

Second, the Commission's historic treatment provides a sharing of the costs between the Company and its customers, with the Company allocated the carrying costs and customers allocated the principal, which is the greater share of the costs. Such a sharing is appropriate because the rate case expenses are incurred by the Company for the benefit of the Company and its shareholder, not its customers. The Commission affirmed the concept of sharing between the utility and its customers in the Gulf Power Company Order that I previously cited as follows:

As noted above, we have a long-standing practice in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases. The rationale for this position is that ratepayers and shareholders should share the cost of a rate case; i.e., the cost of the rate case would be included in O&M expense, but the unamortized portion would be removed from working capital. This practice underscores the belief that customers should not be required to pay a return on funds spent to increase their rates.

Third, the amortization period proposed by the Company is sufficiently short that the actual carrying costs on the unamortized rate case expense will be relatively minor.

Fourth, such costs are short-lived assets, which typically are financed with short-term debt, further reducing the actual carrying costs on the unamortized rate case expense to relatively minor amounts.

Fifth, the Company will overrecover the carrying costs on the unamortized amount if the recovery is based on the 2013 test year because the unamortized amount will decline each year thereafter, recovery may extend beyond the proposed amortization period, and there is no true-up of the recoveries with the actual costs. The Commission also cited the possibility of overrecovery in the Gulf Power Company Order that I previously cited as follows:

While unamortized rate case expense does not earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the four year amortization period ends. Thus, the amount in O&M expense continues to be collected after total rate case expense has been recovered.

**Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?**

A. The effect is a reduction in the revenue requirement of $0.500 million ($4.826 million times the Company's proposed 10.35% grossed-up rate of return). In addition, there is a related reduction in liability ADIT that I address and quantify in the Rate of Return Issues section of my testimony.

## F. Construction Work in Progress in Rate Base

**Q. PLEASE DESCRIBE THE COMPANY'S REQUEST FOR CONSTRUCTION WORK IN PROGRESS IN RATE BASE.**

A. The Company included $501.676 million (jurisdictional) of construction work in progress ("CWIP") in rate base, ostensibly based on the criteria set forth in FPSC Rule 25-6.0141 for the accrual of allowance for funds used during construction ("AFUDC"), according to its response to OPC Interrogatory 32. The return on this CWIP contributes $51.930 million to the Company's claimed revenue requirement ($501.676 million times the Company's proposed 10.35% grossed-up rate of return). The Company provided a listing of its CWIP in rate base by project in response to Staff Interrogatory 98 (Attachment 2), which I have replicated as my Exhibit__(LK-10) for reference purposes. The largest dollar amounts for individual projects and more than half of the projects in the aggregate are for intangible, production, and transmission projects.

**Q. ARE THERE OPTIONS AVAILABLE TO UTILITIES TO PROVIDE RECOVERY COSTS INCURRED TO FINANCE CONSTRUCTION PROJECTS?**

A. Yes. There are two options for the recovery of the costs incurred to finance projects during construction. One option is to provide the utility current recovery of the financing costs by including the CWIP in rate base during construction. The other option is to add the financing costs to CWIP in the form of allowance for funds used during construction ("AFUDC") and to provide the utility recovery of the AFUDC through a return of (depreciation) and on the AFUDC included in plant in-service over the lives of the underlying assets. Thus, the recovery is a matter of timing rather than economics because the net present value is generally considered to be equivalent if the return on rate base, the AFUDC rate, and the discount rate are equivalent.

**Q. GIVEN THAT THE RECOVERY IS A MATTER OF TIMING RATHER THAN ECONOMICS, SHOULD THE RECOVERY OF THE FINANCING COSTS BE UPFRONT OR OVER THE LIVES OF THE UNDERLYING ASSETS?**

A. The recovery generally should be over the lives of the underlying assets for several reasons. First, the financing cost during construction is a cost of the asset, similar to all the other costs included in CWIP. There is no compelling reason to provide upfront recovery of one component of the asset's cost, particularly when this decision is discretionary, the discretion rests with the Commission, and the

Rule itself explicitly recognizes that the Commission may modify the criteria set forth in the Rule.

Second, by definition, assets have lives that extend beyond the test year. Thus, all costs associated with the construction or completion of an asset that is constructed or acquired to provide service should be recovered from customers over the period that the asset provides service to those customers. This is the concept underlying the capitalization of plant costs and the depreciation and recovery of those costs over the assets' estimated service lives.

Third, there is the issue of intergenerational equity. If the recovery is upfront through CWIP in rate base, then today's customers pay for a component of the asset's cost before it provides any service and then future generations customers are relieved of a cost of service that should be allocated to and borne by them. This is particularly true when the customer demographics reflect transient and older residential customers as well as significant customer growth over the lives of the assets. In other words, CWIP in rate base provides an unnecessary and inappropriate subsidy from today's customers, many of whom will not continue taking service from FPL decades into the future, to future generations of customers, many of whom will be new customers of FPL in the future.

**Q. DOES THE COMMISSION HAVE A RULE CONCERNING THE ACCRUAL OF AFUDC?**

A. Yes. FPSC Rule 25-6.0141(1)(a) sets forth certain criteria for the accrual of AFUDC for projects that "involve gross additions to plant in excess of 0.5 percent of the sum of the total balance in Account 101-Electric Plant in Service, and Account 106, Completed Construction not Classified, at the time the project commences" and "are expected to be completed in excess of one year after commencement of construction." I have attached a copy of this FPSC Rule as my Exhibit___(LK-11) for reference purposes.

Q. **DOES THE RULE ITSELF ALLOW THE COMISSION TO CONSIDER THE POTENTIAL IMPACT OF CWIP ON RATES AND REVISE THE CRITERIA SO THAT MORE CWIP PROJECTS ARE ELIGIBLE FOR AFUDC?**

A. Yes. FPSC Rule 25-6.0141(1)(g) states that "On a prospective basis, the Commission, upon its own motion, may determine that the potential impact on rates may require the exclusion of an amount of CWIP from a utility's rate base that does not qualify for AFUDC treatment per paragraph (1)(a) and to allow the utility to accrue AFUDC on that excluded amount."

Q. **SHOULD THE COMMISSION EXCLUDE A PORTION OF THE CWIP FROM RATE BASE AND REVISE THE CRITERIA SO THAT THESE AND OTHER ADDITIONAL CWIP PROJECTS WILL QUALIFY FOR AFUDC?**

A. Yes. Many of the CWIP projects that the Company included in rate base are long-lived generation and transmission assets. This case provides an opportunity for the Commission to ensure that all the costs of these long-lived assets, including the financing costs during construction, are borne by the customers who ultimately are served by these assets. The Commission can achieve this objective by removing these CWIP projects from rate base in this proceeding and authorizing the Company to use AFUDC instead. Providing a current return on the cost of these CWIP projects in this proceeding inappropriately forces today's customers to pay a portion of the cost of the assets before they are placed in-service rather than allocating the financing costs on these projects during construction to the future generations of customers who will be served by the assets. Limiting AFUDC in this manner also harms the Company by precluding it from accruing AFUDC on construction projects that fail to meet the criteria between rate cases even though the Company actually incurs the financing costs. Thus, qualifying more CWIP projects for AFUDC benefits both the Company and its customers.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend that the Commission prospectively modify the criteria for AFUDC to require a construction period of only six months rather than the one year set forth in the Rule, and require a threshold project cost of $0.5 million or more rather than the 0.5% of the Company's total plant in service set forth in the Rule. The effect of this modification in the context of this case would be to reduce the CWIP in rate base to $250 million, or approximately one-half of the CWIP amount included in rate base by the Company. This is based on the dollar amounts of the CWIP projects included in rate base and listed in its response to Staff Interrogatory 98 (Attachment 2), and which I have replicated as my (Exhibit____LK-10). Again, adoption of this recommendation would benefit the Company in the long run by providing it the opportunity to recover its financing costs and would benefit current customers by eliminating from rates the costs of facilities that will benefit future customers.

**Q. WHAT IS THE EFFECT FPL'S REVENUE REQUIREMENT OF YOUR RECOMMENDATION?**

A. The effect is to reduce the Company's claimed revenue requirement by $26.052 million ($251.676 million times 10.35%).

## G. Depreciation Reserve Surplus

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR COMPLETING THE FOUR YEAR AMORTIZATION OF THE DEPRECIATION RESERVE SURPLUS AUTHORIZED IN THE PRIOR BASE RATE PROCEEDING.**

A. The Company quantified $191 million as the remaining amount of depreciation reserve surplus at December 31, 2012 after estimating the amount that it will use in 2012 to achieve the 11.0% return on equity pursuant to the settlement agreement in the prior proceeding. It then used that $191 million as a reduction to the revenue requirement for the 2013 test year. The final amortization of $191 million, together with the estimated $703 million through December 31, 2012, sums to the total $894 million that was available pursuant to the settlement terms addressing the depreciation reserve surplus in the prior base rate proceeding.

The Company does not propose a true-up of the $894 million based on the amount it actually uses in 2012 to achieve the 11.0% return on equity pursuant to the settlement agreement in the prior proceeding. The Company argues that this is the "most balanced and reasonable approach" and is "fair to both customers and the Company." [Ousdahl Direct at 22].

**Q. DID THE COMPANY PROPOSE THAT THE REVENUE REQUIREMENT INCREASE BY $191 MILLION AFTER 2013 ONCE THE AMORTIZATION OF THE DEPRECIATION RESERVE SURPLUS AUTHORIZED IN THE PRIOR BASE RATE PROCEEDING WAS COMPLETED?**

A. No. The Company's proposal is described by Ms. Ousdahl in her Direct Testimony. She does not propose that the revenue requirement increase by $191 million after 2013. She does not propose a true-up in the event that the Company's estimated amortization in 2012 is incorrect. She does not propose or request the necessary ratemaking authority to be able to continue an accounting adjustment for the negative depreciation expense (amortization of the reserve surplus) after the 2013 test year, which would reduce the accumulated depreciation reserve beyond the $894 million authorized in the prior base rate proceeding.

The Company's proposal also is described by Mr. Barrett in his Direct Testimony. He states "This amount [the $191 million] is already reflected in, and thus lowering by $191 million, the test year revenue requirements. All other things equal, earnings in 2014 will be $191 million lower compared to 2013, even with the requested base rate relief in 2013." [Barrett at 19]. Thus, Mr. Barrett suggests that the Company is voluntarily forgoing any rate increase in this proceeding, or any deferrals (negative amortization expense that would reduce the accumulated depreciation reserve), to recover the lost earnings that might occur after the expiration of the amortization of the reserve surplus in 2013.

**Q. WOULD THE COMPANY BE ABLE TO CONTINUE ON ITS OWN VOLITION AN ACCOUNTING ADJUSTMENT FOR THE NEGATIVE DEPRECIATION EXPENSE AFTER 2013 AND EFFECTIVELY DEFER AN ADDITIONAL $191 MILLION EACH YEAR WITHOUT COMMISSION AUTHORIZATION?**

A. It could not legitimately do so because there would be no rate action of a regulator, one of the requirements for such an accounting adjustment under Generally Accepted Accounting Principles ("GAAP"). If the Company did so anyway, then any resulting reduction in the accumulated depreciation reserve would be unauthorized and would be subject to disallowance in subsequent rate proceedings and earnings surveillance reports.

**Q. DO YOU PROPOSE ANY CHANGE IN THE COMPANY'S PROPOSAL TO USE THE $191 MILLION TO REDUCE THE REVENUE REQUIREMENT IN THIS PROCEEDING?**

A. No. However, the amount proposed by the Company is directly dependent on the accuracy of the Company's projected utilization of the depreciation reserve surplus in 2012 to achieve an 11.0% return on equity. The actual remaining depreciation reserve surplus at December 31, 2012 may be more or less than the Company projected for purposes of this rate proceeding.

Q. **WHY DO YOU RAISE THIS ISSUE IF YOU ARE NOT MAKING ANY RECOMMENDATION THAT HAS AN EFFECT ON THE REVENUE REQUIREMENT IN THIS PROCEEDING?**

A. It is important for several reasons. The first reason is to ensure the Commission understands that the Company may plan or actually attempt to continue an accounting adjustment to the accumulated depreciation reserve after 2013 that will increase rate base by $191 million each year until rates are again reset. The Commission should preemptively reject that possibility so that it does not need to be litigated after-the-fact in the next base rate proceeding.

The second reason is that the Company might request an accounting order after this proceeding seeking to continue an accounting adjustment to the accumulated depreciation reserve. Again, the Commission should preemptively address and reject that possibility so that it and the parties are not blindsided after this proceeding is concluded and a decision rendered under the assumption that such an accounting adjustment has not been requested or authorized and thus, will not be made.

The third reason is that the Company is required to file a new depreciation study in March 2013. If the depreciation rates are reduced as a result of that study and the Company retains the savings in depreciation expense until the next base rate proceeding, then the Company could retain an amount potentially in excess of the $191 million.

The fourth reason is that the Company's sales may rebound strongly as the economy recovers, particularly as the south Florida economy recovers. In that case, the Company will retain the increase in earnings until base rates are again reset and that annual increase may exceed the $191 million on a before tax basis.

## III. OPERATING INCOME ISSUES

### A. Nuclear Outage Maintenance Expense Accrual

### 1. Nuclear Outage Maintenance Expense Accrual Is Excessive

**Q. PLEASE DESCRIBE THE NUCLEAR OUTAGE MAINTENANCE EXPENSE INCLUDED BY THE COMPANY IN THE TEST YEAR.**

A. The Company included $105.463 million in nuclear outage expense in the test year (total Company), as shown in its response to SFHHA POD 9, page 1 of 23. This represents an increase of $21.137 million compared to the $84.326 million for 2011 and an increase of $11.860 million compared to 2012, as shown in its response to SFHHA POD 9, page 1 of 23. These amounts are included in the account 528 amounts shown on Schedule B-6. I have replicated the Company's response to SFHHA POD 9 as my Exhibit___(LK-12).

**Q. SHOULD THE COMMISSION APPROVE SUCH AN INCREASE?**

A. No. First, the Company's request for the projected test year is significantly more than it actually has incurred or budgeted for nuclear outage maintenance expense in prior years and more than it projects in later years. The Company actually incurred $92.129 million in 2010, $84.326 million in 2011, and has budgeted $93.603 million for 2012, according to its response to SFHHA POD 9. After the test year, the Company projects that it will incur $96.941 million in 2014 and $61.060 million in 2015, also according to its response to SFHHA POD 9.

Second, the Company's request fails to recognize that in some years it incurs the costs for three outages and in some years it incurs the costs of only two outages. The Company made no attempt to levelize these costs to reflect the average cost over a three year period, which would include two years with three outages and one year with two outages.

Third, the Company cannot project with certainty either the timing or the costs of its outages. For example, the most recent outage schedule reflects delays in the schedule of approximately six months compared to the prior schedule, according to the Company's response to SFHHA POD 9. Under the prior schedule, Port St. Lucie 1 was scheduled for outages in Fall 2011, Spring 2013 and Fall 2014, according to Bates page 005632. The present schedule reflects a continuation of the Fall 2011 outage into Spring 2012, followed by a Fall 2013 outage and a Spring 2015 outage, according to Bates page 005623.

Fourth, the Company's requested expense is simply an estimate for ratemaking purposes, an estimate that it has every incentive to maximize. That is because the Company does not actually expense the amount authorized by the Commission for recovery. Instead, the Company unilaterally determines the actual outage expense based on its preemptive amortization of the projected costs of the next outage for each unit, which it then trues up to the amounts actually incurred during the actual outage.

**Q. WHAT DO YOU RECOMMEND FOR THE NUCLEAR OUTAGE MAINTENANCE EXPENSE?**

A. I recommend that the Commission use the average of the three most recent years. This has the effect of levelizing the expense over the three outage and two outage years and has the effect of imposing a reality check on the Company's projected outage expense for the test year. I also recommend that the Commission modify the ratemaking, and thus, the Company's accounting for this expense, which I discuss in the next section of my testimony.

**Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION ON THE REVENUE REQUIREMENT?**

A. The effect is to reduce the Company's revenue requirement by $15.183 million after being grossed up by the conversion factor for expenses.

**2. Nuclear Outage Maintenance Expense Accrual Methodology Is Flawed**

**Q. PLEASE DESCRIBE THE COMPANY'S NUCLEAR OUTAGE EXPENSE ACCRUAL METHODOLOGY.**

A. The Company uses a *pre*paid variation of reserve accounting for nuclear maintenance outages. Under this variation, the Company schedules future maintenance and refueling outages and projects the costs of the outages before the costs actually are incurred and the full scope of the outages actually is known. The Company then preemptively amortizes the projected outage costs to maintenance expense (recorded in account 528) *before* the outages actually occur. The Company accumulates the preemptive maintenance expense in the maintenance reserve as a regulatory liability (recorded in account 228.4), similar to storm damage reserve accounting. The Company then charges the actual cost of each outage to the maintenance reserve when those costs are incurred, which has the effect of reducing the liability amount of the reserve. In this manner, the outage costs are prepaid prior to the outages. The monthly expense accruals and the reserve amounts were provided by the Company in response to SFHHA Interrogatory 194. I have attached a copy of this response and selected pages from the attachment as my Exhibit___(LK-13).

If the cost of the outage is greater than the amount that was accrued, then the excess amount is expensed as incurred, according to the Company's response to SFHHA Interrogatory 196. If the cost of the outage is less than the amount that was accrued, then the Company reverses the excess amount as a negative expense, also according to its response to SFHHA Interrogatory 196. I have attached a copy of the response to SFHHA Interrogatory 196 as my Exhibit___(LK-14).

**Q. IS THERE A VARIATION OF THE RESERVE ACCOUNTING USED BY OTHER UTILITIES?**

A. Yes. Other utilities use a *post*paid variation of reserve accounting. Instead of amortizing a *projected* outage cost to maintenance expense *before* the outage occurs, those utilities amortize the actual cost of the outage *after* the outage occurs. Under both the prepaid and postpaid variations, the actual cost of the outage is charged against the reserve. Under the prepaid variation, when the actual costs incurred are charged against the reserve, it eliminates the regulatory liability that had been accrued for that outage. Under the postpaid variation, when the actual costs incurred are charged against the reserve, it creates a regulatory asset for that outage, which then is amortized to expense after the fact.

The difference in the two variations is the timing of when the outage costs are charged to expense (before the outage for the prepaid or after the outage for the postpaid). The difference in the timing is important from both a cost perspective and from an end of life perspective.

Q. **WHAT IS THE TIMING OF THE FUTURE OUTAGES REFLECTED IN THE COMPANY'S NUCLEAR OUTAGE MAINTENANCE EXPENSE?**

A. The timing of the outages used for the Company's prepaid nuclear outage expense ranges from 2013 through 2015. The outage expense accruals for the 2013 test year included amortization of estimated costs for the Turkey Point 3 Fall 2013 and Spring 2015 outages; the Turkey Point 4 Fall 2012 (carried over to Spring 2013), Spring 2014, and Fall 2015 outages; the Port St. Lucie 1 Fall 2013 and Spring 2015 outages; and the Port St. Lucie 2 Spring 2014 outage, according to the Company's response to SFHHA POD 9. It should be noted that the dates of the outages shown in the response to SFHHA POD 9 on Bates page number SFHHA 005632 are not correct, although the amounts shown correspond to outage dates cited and the other pages included in the response to SFHHA POD 9.

Q. **DOES THE COMMISSION HAVE THE CHOICE OF WHETHER TO ALLOW THE COMPANY TO USE RESERVE ACCOUNTING, AND IF SO, WHETHER TO USE PREPAID OR POSTPAID RESERVE ACCOUNTING?**

A. Yes. The ratemaking purpose of reserve accounting is to normalize the annual nuclear outage maintenance expense in order to avoid an unusually high or low expense in any year due to the frequency and cost of outages. For example, the Company has three outages in some years and two outages in other years. The outages for each unit generally are scheduled to occur every 18 months. This ratemaking purpose carries over into the accounting for nuclear outage maintenance expense as the result of the rate actions of a regulator, i.e., the Commission.

The Commission controls whether the Company uses reserve accounting and controls whether it uses the prepaid variation or the postpaid variation. In the case of reserve accounting, there is a shift from one period to another when the cost of the outages are expensed. Under the prepaid variation, this shift is to periods preceding the outage. Under the postpaid variation, this shift is to periods after the outage. The reserve accounting is available to the Company for accounting purposes only because it is subject to rate regulation. If the Company were not a utility subject to rate regulation and had not been authorized to do so by the Commission, then the Company would be required to expense the nuclear outage maintenance costs when they were incurred.

**Q. WHY SHOULD THE COMMISSION RECONSIDER ITS DECISION TO USE THE PREPAID VARIATION AND INSTEAD ADOPT THE POSTPAID VARIATION OF RESERVE ACCOUNTING?**

A. There are two reasons. One is the cost to customers and the other is to avoid a mismatch in the timing of the recovery that results under the prepaid method, which is inconsistent with the timing of recovery reflected in the end of life amortizations of materials and supplies and the remaining nuclear fuel core.

Regarding the first reason, the Commission's primary concern should be the cost to customers. The net present value is the same to the Company under either variation because it collects the costs from customers and pays or earns a return on the reserve, net of the ADIT reflected in the cost of capital. However, the net present value of the two variations differs to the customers. The prepaid variation is more expensive to the customers because they lose a portion of the return on their prepayment due to the fact that the Company has to pay income taxes on the prepaid amounts. That is not true with the postpaid variation. In the postpaid variation, the customers have to pay a return on the amounts paid by the Company, but the return is net of the savings from the deduction of the costs for income taxes.

Regarding the second reason, the prepaid variation results in a stranded liability at the end of each unit's life because revenue requirement includes preemptively the cost of future outages that never will be incurred because there will be no future outages after the unit is retired. This problem does not exist with the postpaid approach because the amortization of the cost associated with the final maintenance outage occurs over each unit's remaining life. Unlike the situation with the prepaid variation, there is no prepayment by customers of outage costs for outage that never will occur.

The Commission previously authorized recovery of the "end of life" materials and supplies inventory and nuclear fuel core so that there will be no stranded costs to recover from future customers after the units are retired.

Similarly, the Commission should ensure that there is no end of life stranded liability after the units are retired. There will be an end of life stranded liability for the maintenance outage costs under the prepaid variation of reserve accounting, but not under the postpaid approach.

Thus, the postpaid approach is conceptually and practically superior to the Company's prepaid approach. The postpaid approach results in a lower cost to customers, does not harm the Company, and ensures that there is no stranded liability at end of life. The prepaid approach requires customers to pay for maintenance preemptively in the years before the outage. In contrast, the postpaid approach matches recovery of the maintenance costs incurred to allow the unit to continue operating until the next outage with the service provided during the same period until the next outage. The postpaid approach provides a better matching of expense to the period that benefits from the cost and for which the cost was incurred.

The superiority of the postpaid approach can be illustrated by fast-forwarding to the last outage before the unit is retired. Under the postpaid approach, the cost of that last outage will be amortized over the remaining life of the unit and there will be no remaining regulatory asset when the unit is retired. Under the prepaid approach, the Company never again will incur maintenance outage costs because there never again will be another maintenance outage, yet it will continue to accrue and recover outage maintenance expense over the remaining life of the unit. This necessarily will result in a stranded liability for an outage that never will occur after the unit is retired.

**Q. WHAT CHANGES ARE NECESSARY TO CONVERT TO THE POSTPAID VARIATION FROM THE PREPAID VARIATION?**

A. The conversion to the postpaid variation will require a transition that does not result in either excessive or inadequate annual recovery in the revenue requirement. The Commission first should determine the appropriate annual expense, which I addressed in the prior section of my testimony. To the extent that this annual expense is in excess of the amortization expense based on the actual outage costs incurred and deferred during the test year, then the excess expense should be used to increase the regulatory liability that will be amortized to customers. This circumstance will exist only during 2013 in conjunction with the transition. For example, if the Commission sets the total expense at $90 million for 2013 and the amortization expense under the postpaid approach is only $18 million, then the Commission should direct the Company to accrue the $72 million in excess of the amortization expense as an additional regulatory liability.

Also in conjunction with the transition, the Commission should amortize the regulatory liability to customers who have prepaid these amounts in prior years and will continue to add to these prepaid amounts during the transition in 2013. This will result in a negative amortization expense until the regulatory liability is depleted. A two or three year amortization period would be reasonable for this purpose.

Finally, in conjunction with the transition and discontinuing the prepaid approach, the Commission should direct the Company to implement the postpaid approach and to establish regulatory assets for the actual costs of outages to be followed by amortization of the actual costs over the next 18 months, or until the end of the next outage.

**Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION TO CONVERT FROM A PREPAID VARIATION TO A POSTPAID VARIATION OF THE RESERVE ACCOUNTING FOR THE NUCLEAR MAINTENANCE EXPENSE?**

A. The effect is a reduction in the revenue requirement of $37.402 million, after application of the expense conversion factor, to reflect a reduction in expense for the amortization of the regulatory liability. This reduction in the revenue requirement is in addition to the effect of reducing the nuclear outage maintenance expense to a reasonable amount, as I described in the preceding section of my testimony. I addressed the revenue requirement effect of the change in rate base in the Rate Base section of my testimony and the revenue requirement effect of the related change in ADIT in the Rate of Return section of my testimony. The computations of the expense, rate base, and ADIT components are detailed on my Exhibit___(LK-9) and rely on the outage timing and cost information provided by the Company in its response to SFHHA POD 9.

## B. Vegetation Management

**Q. PLEASE DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF VEGETATION MANAGEMENT EXPENSE FOR THE 2013 TEST YEAR AND COMPARE THAT REQUEST TO THE ACTUAL VEGETATION MANAGEMENT EXPENSE IN THE PRIOR THREE YEARS.**

A. The Company requests $68.655 million (total Company) for vegetation management expenses for the test year, according to the Company's response to OPC Interrogatory 200. This compares to actual expense of $52.650 million in 2009, actual expense of $57.600 million in 2010, actual expense of $60.382 million in 2011, and budgeted expense of $59.230 million in 2012, also according to the Company's response to OPC Interrogatory 200.

In addition, the Company provided more detail regarding its reliability programs, including vegetation management, in response to OPC Interrogatory 134. It provided the amounts expensed for vegetation management for the years 2006 through 2013 separated into reliability and hardening and provided the miles of lines trimmed, treated and/or cut in response to OPC Interrogatory 225. The Company described its plan to achieve a six year lateral trim cycle in response to Staff Interrogatory 200 and its three year feeder trim cycle in response to Staff Interrogatory 219. The Company also described its transition to a six year lateral trim cycle in its response to OPC Interrogatory 98 in Docket No. 080677-EI.

I have attached a copy of the Company's responses to OPC Interrogatory 200 as my Exhibit___(LK-15), OPC Interrogatory 134 as my Exhibit____(LK-16), OPC Interrogatory 225 as my Exhibit___(LK-17), Staff Interrogatory 200 as my Exhibit___(LK-18), Staff Interrogatory 219 as my Exhibit___(LK-19), and OPC Interrogatory 98 in Docket No. 080677-EI as my Exhibit___(LK-20).

**Q. SHOULD THE COMMISSION ALLOW RECOVERY OF $68.555 MILLION FOR THE TEST YEAR?**

A. No. There is no valid justification for an increase of $9.425 million in vegetation management expense in 2013 compared to 2012. This represents a year over year increase of 16%. The Company will be on a 6 year trim cycle starting in 2013 after incurring additional expense in prior years in order to move to this cycle program and frequency. If anything, the expense should decline in the test year, not increase, and the savings that should result from fewer and/or shorter duration outages due to the increased trimming in prior years. If the incremental expense incurred to move to a 6 year trim cycle does not result in savings in 2013 instead of an increase, then there is a serious question as to whether the incremental expenses were prudent and reasonable.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend that the Commission limit the vegetation management expense to the budget 2012 level. This equates to a revenue requirement reduction of $9.447 million grossed up to reflect bad debt and regulatory assessment fees. The 2012 level is approximately equal to the actual 2011 level, which followed two years of significant increases as the Company modified its vegetation management programs to a cycle basis and reduced its reliance on contractors.

Another factor to consider is that the Company has incurred tens of millions of dollars to implement a series of initiatives to improve system reliability. For example, the initial 8 year cycle of pole inspections and replacements will be completed in 2013, according to Mr. Hardy and according to the Company's responses to OPC Interrogatories 199 and 227. [Hardy Direct at 8]. These expenditures included both capital and expense. The Company acknowledges that these initiatives should result in savings, according to its response to OPC Interrogatory 199, but the full impact has not been quantified, according to its response to OPC Interrogatory 200, and there has been no showing that any savings in restoration costs are included in the test year. I have attached a copy of the Company's response to OPC Interrogatory 199 as my Exhibit___(LK-21) and to OPC Interrogatory 227 as my Exhibit___(LK-22).

Yet another factor to consider is the fact that the Company has reflected only a minimal amount of savings from the implementation of AMI meters. Such savings occur from reductions in meter reading and related expenses, among others.

At some point, the customers need to see savings from the costs of these initiatives rather than ever-increasing expenditures. Holding the line on vegetation management expense, while not storm restoration expense or meter-related expense, nevertheless, would ensure that there is at least some quantifiable benefit from the investments to improve reliability and the installation of smart meters.

**C. Savings from Installation of AMI Meters**

**Q. IN DOCKET NO. 080677-EI, THE COMMISSION DECLINED TO ADOPT AN ADJUSTMENT PROPOSED BY SFHHA TO REFLECT SAVINGS FROM INSTALLATION OF THE AMI METERS IN PROPORTION TO THE NUMBER OF AMI METERS INSTALLED IN THE 2010 TEST YEAR. THE COMPANY CLAIMED THAT THE FULL SAVINGS**

**WOULD NOT BE REALIZED UNTIL THE PROJECT WAS COMPLETED? HOW DOES THE O&M EXPENSE AND SAVINGS REFLECTED IN THIS PROCEEDING COMPARE TO THE COMPANY'S PROJECTIONS IN THE LAST PROCEEDING?**

A. The O&M expense has increased and the savings have decreased as shown in the two tables below. The first table replicates the Table 23 shown on page 140 of the Commission's Order in the prior proceeding. It shows the Company's estimate of $10.458 million in O&M expense and $30.401 million in savings for 2013. The second table shows the amounts reflected in the Company's filing, according to the Company's response to OPC Interrogatory 173, a copy of which I have attached as my Exhibit___(LK-23). The second table shows that the O&M expense included in the test year has nearly doubled from the projection in the prior proceeding, from $10.458 million to $20.739 million. The second table also shows that the savings are substantially less, declining from $30.401 million to $16.996 million. The net effect is that an increase in O&M expense of $23.687 million in 2013 compared to the prior proceeding ($19.943 million net O&M savings in prior proceeding compared to net O&M expense of $3.744 million in this proceeding).

Florida Power & Light Company
AMI Deployment: Meters, Capital Expenditures, O&M Expense, Savings
Docket No: 080677-EI Projections

| Deployment | 2009 | 2010 | 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|---|---|
| Meters (Thousands) | 170 | 1,128 | 1,099 | 1,076 | 873 | 4,346 |
| | | | | | | |
| Capital (Millions) | $43.7 | $168.5 | $158.7 | $151.5 | $122.5 | $645 |
| | | | | | | |
| O&M (Thousands) | $2,274 | $6,883 | $8,910 | $11,882 | $10,458 | |
| Savings (Thousands) | ($167) | ($418) | ($4,700) | ($18,203) | ($30,401) | |
| | | | | | | |
| Net O&M (Thousands) | $2,106 | $6,465 | $4,210 | ($6,321) | ($19,943) | |

Florida Power & Light Company
AMI Deployment: Meters, Capital Expenditures, O&M Expense, Savings
Docket No: 120015-EI Actuals and Projections

| | 2009 | 2010 | 2011 | 2012 | 2013 | 5 Year Total |
|---|---|---|---|---|---|---|
| Meters (Thousands) | 97 | 1,242 | 1,307 | 1,331 | 453 | 4,429 |
| | | | | | | |
| Capital (Millions) | $32.8 | $161.7 | $187.5 | $191.2 | $70.5 | $643.8 |
| | | | | | | |
| O&M (Thousands) | $1,662 | $7,421 | $13,705 | $18,161 | $20,739 | |
| Savings (Thousands) | ($173) | ($449) | ($3,179) | ($9,125) | ($16,996) | |
| | | | | | | |
| Net O&M (Thousands) | $1,489 | $6,972 | $10,526 | $9,036 | $3,744 | |

**Q. SHOULD THE COMMISSION ALLOW THE INCREASE IN EXPENSE IN THIS PROCEEDING COMPARED TO THE PRIOR PROCEEDING?**

A. No. The Commission should hold the Company to its projections. There now are no net savings to offset the capital costs included in the Company's claimed revenue requirement. The elimination of all savings and indeed, the incurrence of net O&M expense is a significant change from the prior proceeding and should not be rewarded in this proceeding. The Commission relied on the Company's projections of savings when it approved the related rate base costs and O&M expenses in the prior proceeding. In fact, the Company projected annual O&M savings after the deployment was completed in 2013 of $36 million, an increase of another $6 million annually in 2014 and thereafter.

The savings were an integral offset to the capital cost of the AMI deployment and the related effect on customers. In fact, if there had been no future O&M savings, then SFHHA may have opposed the AMI deployment in the prior proceeding.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend that the Commission reflect the net O&M savings projected by the Company in the prior proceeding rather than the net O&M expense now included by the Company in its claimed revenue requirement in this proceeding. The difference in O&M expense is $23.687 million (total Company) for the test year. The amount on the table in the Summary section of my testimony represents the jurisdictional amount and is grossed up by the conversion factor for expenses.

## IV. RATE OF RETURN ISSUES

### A. Rate of Return for Base Rates, Recovery Clauses, and AFUDC

**Q. DOES THE COST OF CAPITAL DETERMINED BY THE COMMISSION IN THIS PROCEEDING HAVE EFFECTS BEYOND THE REVENUE REQUIREMENT IN THIS PROCEEDING?**

A. Yes. The Commission's determination of the cost of capital in this case will affect not only the base increase and the Canaveral step increase in this proceeding, but will have other impacts as well. More specifically, the cost of capital approved in this proceeding will be used in all clause recoveries that include rate base investment and a rate of return, except for the nuclear cost recovery, which uses a prescribed fixed cost of capital, according to the Company's response to SFHHA Interrogatory 241. For example, the cost of capital in the environmental cost recovery clause reflects the capital structure and midpoint capital component costs approved in Order No. PSC-10-153-FOF-EI. I have attached a copy of the Company's response to SFHHA Interrogatory 241 as my Exhibit___(LK-24).

The cost of capital also affects the AFUDC rate. The greater the AFUDC rate, the greater the cost of plant in-service included in rate base and the related depreciation included in future revenue requirements over the lives of the assets.

The following table compares the cost of capital approved in the prior proceeding to the Company's request in this proceeding. The table is based on the Company's response to SFHHA Interrogatory 242, which I have replicated as my Exhibit___(LK-25).

Thus, the cost of capital approved in this proceeding affects not only the base revenue requirement and Canaveral Modernization step increases, but also the clause recoveries and the AFUDC rates, which in turn will affect customer rates for decades into the future.

**Q. IF THE COMMISSION APPROVES A REDUCTION IN THE RETURN ON EQUITY, AS PROPOSED BY SFHHA, WHAT GENERAL EFFECTS WILL THAT HAVE IN THIS PROCEEDING AND IN THE CLAUSE RECOVERIES?**

A. In this proceeding, it will result in a reduction to the Company's claimed revenue deficiency and a reduction in the base rate increase, including the Canaveral step increase, all else equal. It also will result in a reduction to the Company's clause recoveries, all else equal, and the reductions in the clause recoveries will partially offset any base rate increases in this proceeding.

## B. Adjust ADIT in Capital Structure for Rate Base Adjustments

**Q. YOU HAVE PROPOSED ADJUSTMENTS TO VARIOUS RATE BASE COMPONENTS THAT HAVE A RELATED ADIT EFFECT. HAVE YOU INCORPORATED THE ADIT EFFECTS OF THE RATE BASE ADJUSTMENTS INTO THE SFHHA REVENUE REQUIREMENT?**

A. Yes. The effect is to increase the ADIT included in the capital structure by $3.898 million on a jurisdictional basis and to decrease the revenue requirement by $0.396 million. The ADIT effects are detailed on my Exhibit___(LK-26). The effects on the cost of capital are detailed in Section II of my Exhibit___(LK-27).

**Q. PLEASE DESCRIBE YOUR EXHIBIT___(LK-27) IN GREATER DETAIL.**

A. I incorporate the effects of all of the SFHHA recommendations to the cost of capital on Exhibit___(LK-27). Section I of this exhibit replicates the Company's request from Schedule D-1a and computes the Company's requested rate of return on a grossed-up basis. This is necessary so that the Company's grossed-up rate of return can be applied to the rate base adjustments in order to quantify the revenue requirement effect of each adjustment.

Each of the subsequent sections sequentially changes either the capitalization or the cost of the capital component and computes the change in the grossed-up rate of return compared to the prior section. This is necessary so that the change in the rate of return can be applied directly to the adjusted rate base in order to quantify the revenue requirement effect of each adjustment to the capitalization or component costs. I multiplied the change in the grossed-up rate of return in each section times the rate base after SFHHA adjustments to quantify the revenue requirement effect of each adjustment to the capitalization or component costs.

**C. Effect of Return on Equity on Revenue Requirement**

**Q. HAVE YOU QUANTIFIED THE EFFECT OF THE SFHHA RETURN ON EQUITY RECOMMENDATION IN THIS PROCEEDING?**

A. Yes. The effect is to reduce the Company's revenue requirement by $387.578 million on a jurisdictional basis, excluding the effects of the Canaveral Modernization step increase. The effect is to reduce the Company's revenue requirement by $155.031 million for each 1.0% change in the return on equity. The computation of the reduction in the grossed-up rate of return and the effects on the Company's base revenue requirement are shown in Section III of my Exhibit___(LK-27).

These effects on the revenue requirement depend on other adjustments that the Commission makes to rate base and the capital structure. I have assumed that the Commission adopts all of the SFHHA adjustments to rate base and the capital structure recommended by SFHAA so that there is no double counting in my quantifications. I also have assumed that the Commisison adopts SFHHA witness Mr. Baudino's primary recommendation for the return on equity. I quantified each adjustment sequentially in the order shown on the table in the Summary section of my testimony. These computations are premised on using Mr. Baudino's primary recommendation for the return on equity together with the SFHHA recommendations for the capital structure, which are interrelated. My computations do not reflect the revenue requirement effects from implementing Mr. Baudino's alternative approach, in which the equity component of the capital structure would be reduced from that sought by the Company in exchange for a greater return on equity than that recommended by Mr. Baudino in his primary recommendation.

**D. Rate of Return for Canaveral Modernization Step Increase**

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED COST OF CAPITAL TO APPLY TO THE CANAVERAL MODERNIZATION PROJECT RATE BASE.**

A. The Company proposes a capital structure consisting of 60.97% common equity and 39.03% long-term debt, according to Schedule D-1a for the Canaveral Step Increase. The Company included the ADIT as a reduction to the Canaveral step rate base rather than in the cost of capital at zero cost.

**Q. IS THE AMOUNT OF ADIT SUBTRACTED FROM RATE BASE CORRECT?**

A. No. It is understated. The tax depreciation consists primarily of bonus depreciation rather than MACRS depreciation. The bonus depreciation is available in its entirety the day that the asset is placed in service for tax purposes. On Schedule C-22, the Company shows tax depreciation of $432.322 million for federal and state income tax purposes. The federal and state combined income tax rate is 38.58%. Thus, the ADIT should be $166.768 million ($432.322 million times 38.58%). The ADIT used by the Company to reduce rate base on Schedule B-1 is only $121.936 million, or $44.832 million less than the correct amount.

**Q. WHAT IS THE EFFECT OF USING THE ENTIRE ADIT AMOUNT AS A RATE BASE REDUCTION IN THE CANAVERAL STEP INCREASE?**

A. The effect is a reduction in the Canaveral step increase revenue requirement of $6.052 million. I computed this amount by multiplying the Company's proposed grossed-up rate of return times the $44.832 million additional ADIT reduction to the Canaveral step increase rate base.

**Q. HOW DOES THE COMPANY'S PROPOSED CAPITAL STRUCTURE FOR THE CANAVERAL STEP INCREASE COMPARE TO THAT USED TO REMOVE THE CANAVERAL RATE BASE AMOUNTS FROM THE BASE REVENUE REQUIREMENT?**

A. It reflects a greater ratio of higher-cost common equity and a lesser ratio of lower cost long-term debt. More specifically, the Company made adjustments in the base revenue requirement to remove the construction work in progress from the common equity and long-term debt of $315.214 million and $213.806 million, respectively, as shown on Schedule D-1b. The Company's adjustments reflect a capital structure of 59.58% common equity and 40.42% long-term debt.

**Q. SHOULD THE COMMISSION USE A RICHER COMMON EQUITY RATIO FOR THE CANAVERAL STEP INCREASE THAN FOR THE BASE REVENUE REQUIREMENT EXCLUDING THE CANAVERAL STEP INCREASE?**

A. No. There is no justification to increase the common equity ratio and reduce the long-term debt ratio for the Canaveral step increase. The common equity and long-term debt ratios should remain the same as those used for the base revenue requirement.

**Q. HAVE YOU QUANTIFIED THE EFFECT OF USING THE SAME COMMON EQUITY AND LONG-TERM DEBT RATIOS AS THOSE USED FOR THE BASE REVENUE REQUIREMENT?**

A. Yes. The effect is to reduce the Company's Canaveral step increase by $1.451 million. The computations are detailed on my Exhibit___(LK-28). I computed this in a manner similar to the computations of the incremental effects of the SFHHA primary recommended adjustments to the Company's proposed cost of capital for the base revenue requirement. Section I of Exhibit___(LK-28). replicates the Company's proposed cost of capital for the Canaveral step increase. Section II of Exhibit___(LK-28) reflects the computation of the cost of capital with this change. I computed the reduction in the grossed-up rate of return in

Section II compared to Section I and multiplied the difference times the Canaveral rate base, as adjusted for all SFHHA recommendations.

**Q. HAVE YOU QUANTIFIED THE EFFECT OF THE SFHHA RETURN ON EQUITY RECOMMENDATION IN THIS PROCEEDING ON THE CANAVERAL STEP INCREASE?**

A. Yes. The effect is to reduce the Company's Canaveral step increase revenue requirement by $18.876 million on a jurisdictional basis. The effect is to reduce the Company's Canaveral step increase revenue requirement by $7.550 million for each 1.0% change in the return on equity. These effects on the revenue requirement depend on other adjustments that the Commission makes to the Canaveral step increase rate base and capital structure. I have assumed that the Commission adopts all of the SFHHA adjustments to the rate base and capital structure so that there is no double counting in my quantifications. I quantified each adjustment sequentially in the order shown on the table in the Summary section of my testimony.

## E. Effect of Rate of Return on Environmental Clause Recovery

**Q. HAVE YOU QUANTIFIED THE EFFECT OF THE RATE OF RETURN ON THE ENVIRONMENTAL CLAUSE RECOVERY IN 2013?**

A. Yes. The effect of the Company's proposed cost of capital, including its proposed increase in the return on equity to 11.50% from the 10.0% midpoint approved in the prior proceeding, is an additional increase through the environmental clause recovery revenue requirement of $14.598 million.

In contrast, the effect of the SFHHA recommendation is a reduction of $9.732 million compared to the cost of capital approved in the prior proceeding, with a total reduction of $24.329 million compared to the effects of the Company's request in this proceeding.

The quantifications are detailed on my Exhibit___(LK-29).

## V. STORM COST RECOVERY

**Q. DOES THE COMPANY SEEK RECOVERY OF A STORM DAMAGE EXPENSE ACCRUAL IN THIS PROCEEDING?**

A. No.

**Q. DOES THE COMPANY MAKE ANY PROPOSALS FOR STORM COST RECOVERY?**

A. Yes. The Company proposes that the Commission continue the framework set forth in the 2010 settlement adopted in Docket No 090130-EI, according to Company witness Mr. Moray Dewhurst. [Dewhurst Direct at 51-54]. Mr. Dewhurst also provides a summary description of the relevant terms of the 2010 settlement that would continue in effect under the Company's proposal.

**Q. DOES MR. DEWHURST PROVIDE A COMPREHENSIVE DESCRIPTION OF THE TERMS OF THE 2010 SETTLEMENT THAT CONTROL STORM DAMAGE RECOVERY?**

A. No. Consequently, I will provide a comprehensive description so that the Commission is aware of and can consider all of the terms that would remain in effect if the Company's proposal is adopted. The 2010 settlement framework provides for recovery, on an interim basis, to begin 60 days following the filing of a cost recovery petition and tariff with the Commission, and is based on a 12-month recovery period if the storm costs do not exceed \$4.00/1,000 kWh on monthly residential customer bills. In the event that storm costs exceed that level, any additional costs in excess of \$4.00/1000 kWh may be recovered in a subsequent year or years as determined by the Commission.

In addition, under the terms of the 2010 Settlement Agreement the Company may petition the Commission to increase the \$4.00/1,000 kWh charge during the initial 12-month recovery period in the event that the Company incurs storm recovery costs in excess of \$800 million in a given calendar year, inclusive of the amount necessary to replenish the storm damage reserve to the level that existed as of the date the settlement was implemented.

Finally, the settlement precludes any offset to the Company's storm damage recovery based on a "rate case" type of inquiry or the use of any form of earnings test or measure or consideration of previous or current base rate earnings or level of theoretical depreciation reserve.

**Q. SHOULD THE COMMISSION ADOPT THE COMPANY'S PROPOSAL FOR FUTURE STORM DAMAGE RECOVERY?**

A. No. The Commission should reject this proposal. It not only is unnecessary, it also is harmful to customers. As a foundational matter, the storm damage recovery mechanism was an element in the 2010 settlement agreement. This was an agreement among the parties to resolve numerous contested issues and does not reflect the litigation positions of the parties, or more specifically, the positions of SFHHA in that docket. The parties only accepted a storm damage recovery mechanism in the context of an overall settlement involving give and take on a multitude of other issues. In addition, the settlement agreement states in paragraph 10 that "No party will assert in any proceeding before the Commission that this Agreement or any of the terms in the Agreement shall have any precedential value." Thus, the Commission should not look to the 2010 settlement agreement as precedent for future storm damage recovery in this or future proceedings.

In addition, the storm damage recovery process set forth in the settlement agreement is flawed when considered on its own merits, which the Commission should do in this proceeding given the Company's proposal. First, it allows recovery of storm damage costs of any amount regardless of whether there remains an amount in the storm reserve. The Company projects a balance in the storm damage reserve of $207.510 million in the test year, according to Schedule B-21. No recovery should be allowed unless the reserve first is exhausted. The reserve is there to provide storm damage recovery, not to exist in perpetuity.

Second, the recovery is effectively self-executing on an expedited basis without Commission review and the opportunity of the various parties to participate in a recovery proceeding. There is no need and not other valid reason for such recovery to be self-executing or to occur on an expedited basis. The

Company has available lines of credit to finance such costs if necessary, the costs of which (commitment and other fees) are included in base rates.

Third, the 12-month recovery period is inordinately and unnecessarily short. If the costs of a storm are hundreds of millions of dollars, then the recovery should be over a longer period, perhaps three to ten years depending on the magnitude of the costs and the frequency of named storms.

Fourth, there is no need and no other valid reason to intentionally restore the reserve to its prior level if in fact it is fully depleted for the costs of future storms. The appropriate and least cost level is $0. That is because the Company can petition the Commission for deferral of storm costs if and when they are incurred and petition the Commission for recovery of the deferred costs.

Fifth, premature recovery before costs are incurred imposes an income tax cost on the recovery that is unnecessary if actual costs are recovered in arrears rather than through estimated costs charged preemptively.

Sixth, Section 366.8260, Florida Statutes, permits FPL to recover its reasonable and necessary storm restoration costs and to replenish its storm damage reserve through a surcharge pursuant to securitization funding. This mechanism of storm damage financing guarantees cost recovery for FPL and provides ratepayers the benefits of low-cost securitization financing. That is a more cost effective means of recovering storm damage costs than the storm damage recovery mechanism FPL proposes here.

Seventh, earnings in excess of the Company's authorized return and other alternatives, such as the excess depreciation reserve, should be considered by the

Commission as potential offsets to the deferral and recovery of storm damage costs. The Commission should not preclude these options from consideration in future proceedings.

Finally, there is no need for the Commission to take any action in this proceeding. The storm damage reserve is substantially funded at this time. In the event that the reserve is depleted, the Company can petition the Commission for deferral of additional costs and recovery of those costs.

**Q. DOES THE EXPOSURE TO STORMS THAT FPL USES TO JUSTIFY ITS REQUESTED EQUITY RETURN (SEE E.G., AVERA DIRECT, P. 10:20-22) COMPORT WITH FPL'S REQUEST TO CONTINUE THE STORM COST RECOVERY PROVISION OF THE SETTLEMENT IN FPL'S LAST RATE CASE?**

A. No. The Company has virtually no risk exposure to storm damage costs. It already has more than $200 million in reserve available for future storm costs, can apply to the Commission to defer and recover costs in excess of the reserve balance, has short term credit facilities that will allow it to temporarily finance storm damage costs at very low interest rates, and has the ability to securitize storm damage costs and recover the debt service associated with the securitization through surcharge.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

**Summary**

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am offering testimony on behalf of the South Florida Hospital and Healthcare Association ("SFHHA"), whose members take electric service on the FPL system.

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

A. The purpose of my testimony is to address the Company's proposed base rate increase and the effects on various recovery clauses, to summarize the effects of the SFHHA recommendations on the Company's claimed revenue requirements, and to address and make recommendations on specific issues that affect the Company's claimed revenue requirements.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I recommend that the Commission increase the Company's base rates on January 1, 2013 by no more than $1.818 million, a reduction of at least $514.703 million from the increase of $516.521 million requested by the Company in this proceeding. I also recommend that the Commission increase the Company's base rates by no more than $147.473 million for the Canaveral Modernization step increase on or about June 1, 2013, a reduction of at least $26.378 million from the step increase of $173.851 million requested by the Company in this proceeding. These recommendations include the effects of SFHHA witness Mr. Richard

Baudino's recommended return on common equity. I summarize the effects of the SFHHA recommended adjustments separately for the two increases on the following tables. In addition, I address the substance of each of these adjustments in the following sections of my testimony, except for the return on common equity, although I quantify the effect of Mr. Baudino's recommendation.

**FLORIDA POWER AND LIGHT**
**REVENUE REQUIREMENT MINIMUM REDUCTIONS RECOMMENDED BY SFHHA**
**DOCKET NO. 120015-EI**
**TEST YEAR ENDING DECEMBER 31, 2013**
**($ MILLIONS)**

| | Amount |
|---|---|
| **Base Rate Change per FPL Filing** | $ 516.521 |
| **Rate Base Adjustments:** | |
| Modify Cash Working Capital from Balance Sheet to Lead/Lag | (16.177) |
| Modify Nuclear Maintenance Reserve from Prepaid to Postpaid | 1.763 |
| Eliminate Unamortized Rate Case Expense | (0.500) |
| Reduce CWIP In Rate Base | (26.052) |
| **Operating Income Adjustments:** | |
| Normalize Nuclear Maintenance Outage Expense | (15.183) |
| Modify Nuclear Maintenance Expense from Prepaid to Postpaid | (37.402) |
| Reduce Vegetation Management Expense | (9.447) |
| Reflect Projected Net AMI Deployment Savings | (23.731) |
| **Capital Structure and Rate of Return Adjustments:** | |
| Adjust ADIT for Rate Base Adjustments | (0.396) |
| Set Return on Equity at 9.0% | (387.578) |
| **Total Minimum SFHHA Recommended Adjustments** | **($514.703)** |
| **Maximum SFHHA Recommendation for Base Rate Change** | **$1.818** |

MR. WISEMAN: And if Mr. Kollen can now make his -- provide a summary of his testimony?

COMMISSIONER BROWN: Yes.

MR. WISEMAN: Thank you.

THE WITNESS: Good afternoon, Commissioners, and Ms. Chairman. In my testimony I summarize the rate increase or the revenue requirement recommendations of SFHHA and address various adjustments to the company's requested base rate increase on January 1, 2013. Also, the requested step increase on June 1, 2013, and the effects of the company's requested rate of return on other clause recoveries.

With respect to the increase on January 1, 2013, I recommend that the Commission increase the company's base rates by no more than $2 million based on various adjustments proposed by SFHHA, which nearly eliminates the increase of $517 million requested by the company in this proceeding.

We propose eight specific adjustments to the company's requested revenue requirement for this increase on January 1, some of which only affect rate base, operating expenses, or rate of return, and some which affect more than one of these components.

The largest adjustment proposed for SFHHA is a reduction on the return on common equity. The company requests an 11-and-a-half percent return on equity, including a 25 basis point adder. The SFHHA recommends a 9.0 percent return on equity with no adder. This issue was addressed by Mr. Baudino, although I quantify the effects of his recommendation.

This recommendation alone constitutes $388 million of the $515 million in adjustments recommended by SFHHA. Each one percent return on equity is worth $155 million in terms of the base rate increase on January 1.

The second and third largest adjustments that we propose are reductions in the nuclear maintenance outage expense. The first of these adjustments is a reduction of $15 million to normalize the outage expense based on the average of the most recent three-year period, and the second of the adjustments is a reduction of $36 dollars to reflect a change in the ratemaking recovery and accounting for nuclear maintenance outage expense from the present prepaid, which the company presently uses, to the post-paid reserve accounting methodology.

The post-paid approach is widely used by other commissions, conceptually superior, provides a more accurate matching of the maintenance expense of the period of maintenance benefits, which is a period of time after the outage, not before the outage, and it provides the company full recovery of its outage costs, adjustment. It doesn't involve a disallowance, it involves correcting the manner in which the cost is recovered.

The fourth largest adjustment that we propose is a reduction in the CWIP rate base by increasing the amount of CWIP that is eligible for AFUDC. This is worth $26 million. Increasing the CWIP eligible for AFUDC is beneficial for customers and for the company.

The fifth adjustment is to reflect the reduction in AMI -- that's the Automated Meter Initiative -- O&M expense. This has the effect of reducing the company's request by $24 million.

The sixth adjustment is a reduction in cash working capital to reflect the estimated effects of using a lead-lag approach instead of the company's outdated balance sheet approach.

The seventh adjustment is a reduction in vegetation management expenses to normalize the expense based on the 2012 prior test year. The final adjustment for the January 1 increase is the exclusion of rate base expenses from rate base.

In addition, I recommend that the Commission increase the company's base rates by no more than $148 million for the Canaveral modernization project on or about June 1, 2013. There are three adjustments:

about June 1, 2013. There are three adjustments: Return on equity that has an effect in that step increase, correction of the accumulated deferred income tax computation and the capital structure, to use the same capital structure that the company proposes in the 2013 test year.

And finally, the Commission should recognize that there is an effect from the rate of return on the various recovery clauses. Primarily the environmental cost recovery clause. Under the company's requested return on equity of 11-and-a-half percent and its capital structure that it proposes, there would be an additional rate increase of $15 million. And that isn't contained in the base rate request, but that will be an addition effect of the company's request. And under the SFHHA recommendation, there will be a reduction from that of $25 million.

I also address the issue of storm damage recovery and propose that the Commission reject the company's proposal. That completes my summary. Thank you.

COMMISSIONER BROWN: Thank you.

MR. WISEMAN: Thank you, Mr. Kollen. Madam Chair, Mr. Kollen is available for cross examination.

COMMISSIONER BROWN: Thank you. Mr. Moyle?

MR. MOYLE: No questions for FIPUG.

COMMISSIONER BROWN: Captain Miller?

CAPT. MILLER: No questions. Thank you.

COMMISSIONER BROWN: FPL?

MR. BUTLER: We do have some questions. Thank you, Madam Chairman.

CROSS EXAMINATION

BY MR. BUTLER:

Q Good afternoon, Mr. Kollen.

A Good afternoon.

Q I'd like to start with your adjustment to FPL's nuclear outage expense accrual methodology that you propose. Am I correct, on page 39 of your testimony, that you identify this adjustment alone as reducing FPL's revenue requirements by about $37.4 million?

A Yes, that's correct, $37.4 million. And this would be the portion of the adjustment that deals with moving from the prepaid to the post-paid reserve accounting.

MR. BUTLER: Madam Chair, at this point I would like to pass out a set of three excerpts from Commission orders that I don't think we'll need to mark as exhibits, as well as also a copy of MFR C-22 from the Canaveral step increase that, again, I don't think we need to mark them as exhibits, but we just would like the witness, as well as the Commissioners --

COMMISSIONER BROWN: Let's look at them first before we take official recognition.

MR. BUTLER: Okay. While they're being passed out, I will just identify on the record what we are passing out. The first is going to be a copy of Order PSC-96-1421-FOF-EI, issued November 21, 1996 in Docket 96-1164-EI.

The second is Order Number 11628 issued in Docket Number 820100-EU issued February 17, 1983. The third order is Order Number 11437 in Docket Number 820097-EU issued December 22, 1982.

And then, as I mentioned, we're distributing a copy for convenient reference of Schedule C-22 from the Canaveral step increase schedules.

COMMISSIONER BROWN: The 1982 order, I do not believe we have that. We just have two orders before us.

MR. BUTLER: Okay. I'm sorry, you're right. We've got one more that's on its way.

COMMISSIONER BROWN: Okay.

BY MR. BUTLER:

Q Mr. Kollen?

Mr. WISEMAN: Mr. Butler, if you could wait a moment, we still haven't been provided the last one.

MR. BUTLER: All right.

COMMISSIONER BROWN: And I was just going to say, seeing no objection from the parties, we will take official recognition of these orders.

MR. BUTLER: Thank you, Madam Chair.

BY MR. BUTLER:

Q Mr. Kollen, Do you have available to you there a copy of Order Number PSC-96-1421?

A I have something that appears to be that. I don't know if it's a complete order or not, but I do have something that is identifiable with that docket number.

Q Okay. Are you aware, Mr. Kollen, that in this order the Florida Public Service Commission authorized FPL to use the prepaid method for accruing nuclear outage expenses?

A Well, I don't see the use of the word prepaid, but it does allow the company to move from a pay as you go to an accrual method. In other words, a reserve method.

Q Do you see the reference to a mechanism being proposed for initially catching up to an initial under-accrual that's discussed on the bottom of page two and the top of page three?

A I do.

Q And that would be consistent with what you would have to do if you had a prepaid method for funding a reserve, wouldn't it?

A I don't know what the reference here is, to whether or not there was some tie-in with a rate case or what. I couldn't say for certain whether or not that would be consistent with a prepaid or not.

Q Do you see the reference earlier on page two -- it's not highlighted -- or above the first highlighting -- to Florida Power Corporation being the only other Florida utility that own and operates a nuclear unit and having a similar reserve having been established for it?

A I do see the reference about a third of the way down, Florida Power Corporation, the only other Florida utility that owns and operates a nuclear unit, has a refueling and maintenance reserve. I see that, yes.

Q Let me ask you, then, to turn to the second order that I had passed out. This is Order Number 11628 dated February 17, 1983. Do you see that?

A Yes, I did.

Q And this is an excerpt from the order. If anyone needs to see a copy of the entire order, we'd certainly be happy to provide it. But would you turn to page 21 of the order? It's the last page in the excerpt that is provided.

MR. WISEMAN: Could we get a copy? I would like to get a copy of the full order to review it, and ask the witness also be provided a full copy.

COMMISSIONER BROWN: Mr. Butler, do you have those available?

MR. BUTLER: We do.

COMMISSIONER BROWN: You may proceed.

BY MR. BUTLER:

Q Okay. Would you agree, Mr. Kollen, that in this order Florida Power Corporation was authorized to accrue to a reserve?

A Yes.

Q Okay. If you'd look at the second paragraph that is highlighted on page 21, would you agree that this discusses the question of whether to have an accrue in advance or prepaid or else instead accruing after the fact a post-paid form of accruals to the reserve?

A Yes, I see that.

Q And would you agree that the Commission concluded with respect to Progress that it would adopt the prepaid approach, an accrue in advance method?

A Yeah. I mean, I don't have any disagreement with that. My recommendation is for the Commission to change that for the reasons in my testimony.

Q But you would agree that the Commission specifically addressed the choice between the two methods and in this order came down on the side of the prepaid reserve funding method, correct?

A Yeah, I don't think there's any question about that. But I'm asking the Commission to revisit the issue for the reasons in my testimony.

Q Now, Mr. Kollen, you recognize in your testimony on page 38 that if there were a conversion from a prepaid to a post-paid accrual method that it would be appropriate to provide some period of transition to sort of make up for the fact that you are switching methods, correct?

A Yes, that's correct. In fact, recently Alabama Power, the Alabama Commission just changed the reserve accounting from a prepaid to a post-paid for Alabama Power Company. And in the calendar year 2011, Alabama Power Company was allowed a zero dollar accrual to refueling maintenance reserve to accomplish that transition.

That isn't my recommendation in this case. I've attempted to smooth that process. But there would be a transition that is necessary.

Q You propose that the transition be over a two to three-year period, correct?

A Yes, that's correct. I quantified it based on a three year, but a two to three-year period would be appropriate. The Alabama Commission decided a one-year was appropriate, but I think a two to three-year would be appropriate.

Q Are you aware of any instances in which this Commission has required amortization of gains or losses on regulatory assets over a period as short as two or three years?

A I don't know. I hadn't really looked at regulatory gains or losses. This would be a change in regulatory recognition of a cost, moving it from a regulatory liability accrued prior to the actual maintenance expenditure being made to one in which it was recovered after the fact.

Q Are you aware of instances in which this Commission has ordered transitions of the sort you just described to be performed over a period as short as two or three years?

A No, I did not investigate transition accounting and the Commission's precedent with respect to that, I just made a proposal I think is reasonable.

Q Mr. Kollen, I'd like to switch gears to talk with you briefly about the subject of the Accumulated Deferred Income Taxes, or ADIT. Is that okay to refer to it that way?

A Yes.

Q That you calculate for the Canaveral step increase adjustment.

A Yes.

Q Do you have there before you available a copy of Schedule C-22 from FPL's Canaveral step increase schedules?

A I do.

Q Okay. I'd ask you to turn to page 50 of your testimony.

MR. WISEMAN: I'm sorry, what page did you say?
MR. BUTLER: Sorry, five-zero, page 50.
THE WITNESS: I do have that.
BY MR. BUTLER:
Q In your calculation of the appropriate amount of deferred taxes, as shown on lines -- well, pretty much in the question and answer that begins on line one and ends on line ten, correct?
A Yes.
Q And you do that by taking $432.322 million of tax depreciation and applying the tax rate to it that combine Federal and state tax rate, correct?
A That's correct.
Q Now, would you look at Schedule C-22? And you'll see on there that there is a line ten, tax depreciation, and that's the same dollar amount that you use multiplied times the tax rate to get the deferred taxes, correct?
A Yes.
Q Okay. Mr. Kollen, is it your understanding concerning the question of determining ADIT that in looking at the deferred taxes generated as a result of accelerated depreciation you'd have to subtract out from the tax depreciation what the book depreciation would have been, anyway?
A Straight line depreciation.

A Yes.

Q And that's an amount of $31.3 million, is that correct?

A Yes, it is.

Q And that would be the book depreciation, last debt AFUDC related to the Canaveral step increase, correct?

A Yes, that's correct.

Q But you haven't subtracted that amount out from the tax depreciation amount in determining your deferred income taxes that you recommend be used as an adjustment for the Canaveral step increase, have you?

A No, that's correct.

Q And do you see on line 13 the reference to state amortization of Federal bonus depreciation?

A Yes, I do.

Q Are you familiar with the provisions of Florida corporate income tax statutes that provide for the Federal bonus depreciation not to be taken as a deduction all in the year that it is incurred but rather to be amortized over a period of seven years?

A No.

MR. BUTLER: Okay. Just one moment, Madam Chair. Madam Chair, I am passing out a copy of Section 220.13 of the Florida Statutes. Again, I don't think we need to mark it as an exhibit, I'm just providing it for to mark it as an exhibit, I'm just providing it for convenient reference.

COMMISSIONER BROWN: I agree, but I will wait for the parties to have a copy of it before I take official recognition.

MR. MOYLE: Madam chairman, the witness, I thought, just testified he didn't have any knowledge or information about this. I don't know that, you know, we're adding anything by giving him a statute he's already said he doesn't know anything about and pointing something out. He can do it in his brief, if he wants to.

COMMISSIONER BROWN: Mr. Butler?

MR. BUTLER: I really just want to confirm whether Mr. Kollen is familiar with this statutory section. If he isn't, I'll move on.

BY MR. BUTLER:

Q Mr. Kollen, are you familiar with the provisions of Section 220.13 of the Florida Statutes concerning the calculation of adjusted Federal income?

A No.

Q Okay, thank you. I won't ask any further questions on that.

COMMISSIONER BROWN: We don't even need to take official recognition of it.

MR. BUTLER: I think it's going to be on the books, regardless.

BY MR. BUTLER:

Q So sitting here today, Mr. Kollen, you don't know one way or the other as to whether the deferred income taxes would need to be adjusted pursuant to the terms of Section 220.13, correct?

A I do not. I assume they would not be, but I don't know if that's consistent with the Florida Statute.

Q Okay. Mr. Kollen, would you agree with me that rate base is calculated on a 13-month average basis?

A For most items, yes, that's correct.

Q Is the calculation of deferred income taxes that you present in your testimony, does that reflect a 13-month average or is that a value as of a particular point in time?

A It's a 13-month average computed based upon an estimated tax approach. I didn't discuss that extensively in my testimony, or not at all, actually, but essentially that carrying charge value from the bonus depreciation is available from day one in a tax year.

In other words, you don't have to wait until the end of the tax year in order to recognize the benefit. And there is a Treasury regulation that applies to that that specifically spells it out. So it's a 13-month average, but I did it as a one-time calculation.

Q Mr. Kollen, have you reviewed FPL's determination of the 13-month average calculation of deferred income taxes that was provided in back-up to its MFRs?

A The back-up to what?

Q Its minimum filing requirement documents.

A Yes.

Q And was that consistent with your understanding as to how the 13-month average is calculated?

A It is, with the exception of the ADIT for large plant additions, such as the Canaveral addition. And what the company did there with respect to the Canaveral addition was just assume that the tax depreciation was available in the month that the addition was made; in other words, in June of 2013.

However, that value or the benefit of it actually is available starting on January 1st in its entirety. And so that's why I calculated it in the manner that I did. The company's calculation is simply wrong.

Q Let me ask you a couple of questions about unbilled revenues, Mr. Kollen. I'd like you to turn to the third case that I had passed out to you, which is the Order Number 11437 dated December 22, 1982. This is an excerpt. We have the full copy of the case available if Mr. Wiseman wants to see it.

COMMISSIONER BROWN: Mr. Wiseman?

MR. WISEMAN: Yes, if we could get the full copy, please. And if we can have a moment just to peruse it quickly.

MR. BUTLER: All right.

COMMISSIONER BROWN: Are you good, Mr. Wiseman?

MR. WISEMAN: Almost. Yes.

COMMISSIONER BROWN: You may proceed.

BY MR. BUTLER:

Q Thank you. Mr. Kollen, do you have an excerpt from Order Number 11437 before you?

A I do.

Q And do you see at the top of page 15 in that excerpt a reference to unbilled revenues?

A I do.

Q Okay. Would you agree with me that at least as reported in this order, Public Counsel opposed the inclusion of unbilled revenues in the calculation of working capital?

A I think it proposed the exclusion. I think your question said inclusion.

Q I'm sorry, I said opposed. They oppose the inclusion, which is the same as proposing.

A I thought you said proposed. Okay, so I think we're clear. Yes, the order says that the Public Counsel has proposed that the company's working capital calculation exclude unbilled revenues.

Q And did the Commission agree with the Office of Public Counsel in that instance?

A It did not. And this would be another instance where I'm asking the Commission to reconsider, but this is an alternative recommendation of SFHHA. Our primary recommendation is that the Commission switch to a lead-lag approach for cash working capital, in which case this wouldn't even be an issue.

Q Mr. Kollen, would you agree that once a utility like FPL provides energy to a customer it has incurred the cost of providing that energy, regardless of whether the customer has yet been billed for the energy?

A Generally I would. The question is, I think, more appropriately framed when is the service paid for. And my position is that the service is paid for through the billed revenues, and that there is a matching there between the billed revenues and the service provided.

Q But you would agree that sort of the period when the company is out the money for having provided the energy and not yet received the revenues would include the period before the bill is rendered to the customer for that energy?

A No, I wouldn't agree with that. I would agree with that with respect to the clause recoveries. In other words, the incremental costs of delivering the energy, but not for the fixed costs that are recovered through the base rates. And the clause expenses, of course, are incremental, but those are not part of the issue here. The unbilled revenues deals only with the base rates and the fixed costs recovered through the base rates, not the variable expenses recovered through the clauses.

Q Mr. Kollen, you mentioned just a moment ago, I think, that you recommend the use of a lead-lag study?

A Yes, that's correct.

Q Have you identified any instance in which this Commission has required the use of a lead-lag study?

A No, and this is something that I'm asking the Commission to consider because it is the predominant methodology, in my experience, and it's a much more sophisticated measurement of the working capital requirement than is the balance sheet.

Q Have you performed a lead-lag study for FPL's 2013 test year?

A No, that would be impossible to do based upon the company's unwillingness to provide the information to do that. And so what I've recommended, instead, is that the Commission just simply set the cash working capital at zero based upon my experience --

MR. BUTLER: I'm sorry, this goes well beyond answering my question. I think that's more explanation than is needed to answer my question.

COMMISSIONER BROWN: I was hoping somebody would speak up. Mr. Kollen, our process here is a simple yes or no, if you can, and then a brief explanation, if that's possible. Try to limit your question -- your answer to the question being posed to you.

THE WITNESS: Yes, Madam Chairman.

COMMISSIONER BROWN: Thank you.

BY MR. BUTLER:

Q Just to complete that thought, Mr. Kollen, are you aware of any other party who has prepared a lead-lag study for FPL's 2013 test year in this docket?

A No. And again, the reason for that is the information just simply isn't available because the company would not provide it.

Q Mr. Kollen, returning to the subject of the Canaveral step increase, but not specifically to the deferred taxes calculation, you basically -- you're proposing three adjustments to FPL's calculation of the Canaveral step increase, is that right?

A Yes.

Q And you've got -- the largest of those by far would be the reduction of roughly $19 million due to the difference between FPL's proposed return on equity and the recommendation of the Hospital Association witnesses, is that right?

A Yes, that's correct.

Q Your disagreement is not based on the actual or projected construction costs or the prudence of those costs, is that correct?

A That's correct.

Q Okay. Do you know whether the Canaveral modernization project was the subject of a prior PSC need determination?

A My understanding is that it was, yes.

Q Okay. I'm going to ask you a question here that initially assumes that your recommended ROE and your proposal for how to handle deferred income taxes and capital structure were approved by that -- or by this Commission. In that scenario, what impact on FPL's earned return would implementation of the step increase have?

A As part of your hypothetical, what is the assumption as far as the company's earned return? Is it at the same level of return that the Commission would adopt for the step increase?

Q That's right.

A Okay. Well, then, it would be the same rate of return. In other words, if the Commission approved a nine percent rate of return for the January 1 increase -- this would be a return on equity -- and in fact the company was earning it, and then the Commission approved a nine percent rate of return and implemented the step increase, the earned return would be nine percent. There wouldn't be any step up or down from that.

Q And if we changed the hypothetical scenario to where FPL's recommendation, Dr. Avera's recommendation on cost of equity and our calculation or deferred income taxes and capital structure were adopted by this Commission for both purposes, for the base rates increase and for the Canaveral step increase, just ask you the same question. What impact on FPL's return under that scenario would the step increase have?

A In order to answer that, I just have to make one additional assumption, and that is that the earned return is the same as the authorized rate of return. In that case, it would be the same.

Q I'd like to ask you a few questions about your recommendation concerning CWIP. Turn to page 21 of your testimony. That's where the discussion starts, but let me more specifically focus you to page 25 of your testimony where your recommendation appears.

A Okay.

Q Now, if I understand your recommendation, it is that the Commission, instead of using its usual rule for the threshold between accruing AFUDC or, instead, including CWIP in rate base, you've proposed to lower those thresholds six months rather than a year and a threshold of only a half-million dollars or more than half a percent of total plant in service for the threshold between where you would, on the lower side of that, include the CWIP in the rate base; the higher side of that you would accrue AFUDC, is that right?

A Yes, that's correct.

Q Okay. And you show here a claim that the effect of this modification would be to reduce the CWIP and rate base to $250 million, approximately one-half of the CWIP amount included in FPL's rate base request, is that right?

A Yes, that's correct. In other words, the CWIP would come out of rate base but it would then be eligible to accrue AFUDC, so the company wouldn't be harmed, it would just have to come back later on and get that in rate base after it was completed.

Q One question on that. When it came back, it would be coming back for necessarily a higher amount -- dollar amount -- to include in rate base than would be the case if it put the CWIP in rate base now, right, because you would have accrued AFUDC on it?

A Yes, that's correct. And that, actually, would benefit the company. But the question is, do you pay now, as far as the customers, or do you pay later over the life of the asset. But you pay the same, basically on a net present value basis. And my proposal is that the customers pay for it over time, rather than up front, just as they would pay for the cost of an asset over time, any other cost of an asset.

Q Okay. So Mr. Kollen, how did you determine the amount of $250 million as a reduction in the CWIP in rate base, given the change in the thresholds that you are proposing? And I probably should provide a little context to the question.

Presumably you made some assessment of what property fit into, you know, the period construction projects of shorter than a year and longer than six months, sort of and/or the dollar threshold that you are applying. And I'm trying to understand where you got the information to make that calculation.

A Yes, I have the company's response to Staff's interrogatory 98, attachment two, which I replicated as my Exhibit LK-10, and I went through those projects. There was additional detail in some of the other discovery responses, and I could see the pattern of the construction expenditures and the larger dollar amounts in the generation and transmission projects.

Q Do I understand from your answer, then, that you were -- you had to make some forms of approximation or of assumptions based on the information you saw to determine what would be -- sort of fall on a different side of the threshold based on the changes that you're recommending?

A That's correct, yes.

Q Returning to the hypothetical I had asked you a few moments ago about the Canaveral step increase and the -- excuse me -- impact of that on FPL's earned return. If FPL were earning slightly above its authorized return at the time that the Canaveral step increase occurred, what would be the impact of including the step increase in FPL's rates?

A At the time of the implementation of the rate increase?

Q Yes.

A Well, it would tend to drag down the overall return. In other words, if the company was slightly earning above -- slightly earning above the authorized rate of return without the step increase, the rates that were authorized as far as a step increase were right at the authorized return, which, of course, is appropriate. That would then tend, on a weighted basis, to drag down the company's earned return, all else equal.

Q Would there be a sort of a complementary effect if the company were earning slightly below its authorized return, that the Canaveral step increase would tend to pull it toward that midpoint?

A Yes, that's correct.

MR. BUTLER: Okay, thank you. That's all the questions that I have for this witness. Thank you, Mr. Kollen.

THE WITNESS: You're welcome.

COMMISSIONER BROWN: Thank you. Office of Public Counsel.

MS. CHRISTENSEN: No questions.

COMMISSIONER BROWN: Retail Federation?

MR. LaVIA: No questions.

COMMISSIONER BROWN: Mr. Saporito?

MR. SAPORITO: Yes, Madam Chair, I have a couple questions.

CROSS EXAMINATION

BY MR. SAPORITO:

Q My name is Tom Saporito. I'm here pro se. Just very quickly, you were asked some questions with the CWIP, your testimony at page 25, lines 12 through 23, I believe. Can you offer an opinion that if your recommendation to the Commission with respect to CWIP were adopted by this commission, would customer bills be lower or higher, in your view, residential customers?

A Well, all customers bills would be lower because the revenue requirement would be lower. In other words, you're taking construction work in progress out of rate base and instead allowing the utility to add the carrying costs on that construction to the construction costs for concrete, labor, et cetera. And so at some later point when those assets are completed, they would come into rate base at that time. But during the period of construction it would result in lower rates for all customers.

Q Thank you. And just very quickly, you provided some responses to some inquiries by counsel at the other end of the table with respect to the nuclear outages. You talked about a transition of two to three years which you were recommending to the Commission to make a change in the way they dealt with that nuclear outage funding.

In your opinion, if the Commission were to adopt your recommendations, would that result in residential customer bills being higher or lower?

A They would be lower, because what has happened to date is that the company has collected amounts for the nuclear refueling outages ahead of the outages. That then creates a situation where there's a pot of money, if you will. If you transition to accruing the cost of the outages after the outage, because the maintenance refers to the period after the outage, which is my recommendation.

So the question is what do you do with that pot of money that's already been collected from the ratepayers. And what I'm proposing is a three-year amortization of that, so that will push down the revenue requirements for all customers, not just the residential customers and just the commercial.

MR. SAPORITO: Thank you. Madam Chairman, that's all I have.

COMMISSIONER BROWN: Thank you. Mr. Hendricks?

MR. HENDRICKS: No questions. Thank you.

COMMISSIONER BROWN: Staff?

CROSS EXAMINATION

BY MR. YOUNG:

Q Good afternoon, Mr. Kollen.

A Good afternoon.

Q How are you? My name is Keino Young. I'm a Staff Attorney. Beginning on page 53 of your testimony, you testify concerning the storm damage reserve, correct?

A Yes, that's correct.

Q Do you know, is FPL's storm reserve a funded reserve?

A It is.

Q And FPL projects -- FPL projects a balance in the storm damage reserve of $207.510 million, correct?

A I knew it was slightly over 200 million. I'll accept that, subject to check.

Q Okay. Is the projected $207.510 million an adequate reserve for a category one or a category two storm?

A I don't know. I haven't made that assessment because it would obviously depend upon the damage. But there are recovery mechanisms in place, coupled with *securitization that would be the preferred method of funding if indeed there was a storm severe enough to deplete that $200 million reserve.

Q All right. Same question: What about a category three or category four storm?

A Same answer.

Q Okay. And what about a category five question -- the same question.

A The same answer.

Q So would it be correct that based on what you said that you're testifying that a surcharge could be applied to FPL customer bills if a storm reserve is not adequate to cover the cost of a major storm?

A Yes, that's correct. I don't propose the company's proposal to continue the approach set forth in the settlement in the 2010 proceeding, but you're correct, there could be a surcharge, as there has been in the past, to recover the securitization cost, for example, of storm damage amounts.

MR. YOUNG: Okay, thank you. No further questions.

CHAIRMAN BRISE: Commissioners? No? Redirect?

REDIRECT EXAMINATION

BY MR. WISEMAN:

Q Mr. Kollen, you were asked some questions about the prepaid versus post-paid accrual method on the nuclear outage maintenance expenses. Do you recall that?

A I do, yes.

Q And you said that you were recommending that the Commission change its policy with respect to that methodology, right?

A Yes, that's correct.

Q Can you explain why it's your proposal that the Commission change that methodology?

A Yes. First of all, it's widely used, the approach that I propose. In fact, I, in representing the Louisiana Public Service Commission Staff, for example, proposed that and it was adopted by the Louisiana Commission.

I've assessed it, the methodology, for other utilities, and it's the most widely-used methodology for nuclear refueling outage maintenance costs.

The approach used for FP&L and Florida Progress, for example are really the outliers. And that is because essentially you're incurring the cost during a refueling outage to restore the unit to operating conditions so that it can operate the next 18 months. That's the primary reason to do the approach that I've recommended.

The second reason is that it's more accurate. Under the company's method or under the prepaid approach, you have to estimate what you're going to do during that next outage, how much it's going to cost, and then you amortize it over the 18 months preceding the outage.

Under my approach, or under the post-paid approach -- it's not really my approach, it's my recommendation. But under my recommendation, the post-paid approach, you know the exact cost of the outage and then you just amortize it during the 18 months after that outage until the next one. So it's much more accurate. You don't have to estimate, you don't have to true it up. It's right on the money.

And then the final point is that as far as the end of life of these nuclear units, you're going to get to the last maintenance outage for the nuclear units, and under the company's methodology, which is the prepaid approach, you're still going to have a maintenance expense that is recovered from customers, even though there's not going to be a final maintenance outage, you know, at the end of the unit's life.

So the Commission previously has adopted recovery of end-of-life materials and supplies on the nuclear units, end of life on the nuclear fuel, and what this proposal does on the post-paid reserve accounting is align the maintenance expense with those decisions that you all made on those two other end-of-life issues.

Q All right, Mr. Kollen, you also said that the

Alabama Commission recently changed its policy to go from the prepaid methodology to the post-paid methodology. Why did the Alabama Commission change its policy?

MR. BUTLER: I'm going to object to this line of questions. I was tempted earlier, but I let Mr. Kollen provide a very detailed explanation of his rationale, but I didn't ask about the Alabama Commission, you know, or its decision. I think that this is well beyond the scope of my questions, which really went to what this Commission's precedent had been.

COMMISSIONER BROWN: Mr. Wiseman, I actually think that calls for speculation by the witness, so I will not allow that question.

MR. WISEMAN: Thank you, Madam Chair.

BY MR. WISEMAN:

Q Mr. Kollen you were also asked about your recommended transition period concerning the transition to prepaid versus post-paid accrual. Do you recall that?

A I do.

Q Okay. Why -- and I think you said you're recommending a two to three-year transition period?

A Yes, that's correct. In fact --

Q Why do you think that that's the -- well, why is that your recommendation?

A Well, the reason that I proposed a two to three-year transition period, in contrast to what the Alabama Commission did with a one-year transition period, is to essentially take that regulatory liability, which is the amount of money that the customers have paid for up front for the next refueling outages, to take that and essentially amortize it over a three-year period, reasonably consistent with a three-year period of time between base rate increases.

If I had proposed a one-year period, like the Alabama Commission used, that would depress the revenue requirement for one year, but then the company would have no amortization of this liability in years two and three, and that would unfairly penalize it. So I tried to provide you a balanced approach, as far as my recommendation.

Q All right, let's switch gears. Do you recall Mr. Butler asked you some questions about your proposal that FPL adopt a lead-lag approach on working capital?

A Yes.

Q Okay. In your answer to Mr. Butler, at one point you said that it's the predominant method. What did you mean by that?

A In my experience there are very few commissions that use the balance sheet method. Almost every commission that I have been before uses the more sophisticated and much more accurate lead-lag approach. It actually measures the time that it takes to get the revenues in that the utility has billed and convert those into cash, compared to the time that it takes --

MR. BUTLER: Madam Chairman, I'm going to object, again. This is a speech. This is not necessary to clear up any point that I raised on my cross examination on this subject, where I was, again, focusing on what this Commission's precedent has been with respect to use of a balance sheet approach and whether there were anybody -- whether there was anybody presenting a lead-lag study.

COMMISSIONER BROWN: Mr. Wiseman?

MR. WISEMAN: I can actually ask him another question that was directly related to Mr. Butler's cross examination on that.

COMMISSIONER BROWN: Okay.

BY MR. WISEMAN:

Q Mr. Butler did ask you whether this Commission had adopted the lead-lag approach, correct?

A Yes, he did.

Q Okay. And you said that you were recommending a change to that policy, correct?

A Yes, that's correct.

Q And why are you recommending a change?

A Well, because that is the latest evolution of the cash working capital approach. Years ago, under FERC, the one-eight of O&M expense formula method was used. Then that evolved into the balance street approach. And now most state commissions use the lead-lag approach. And I just recommend that you do that because it's a much better, much more accurate approach.

Q Mr. Kollen, several times during your discussion of the lead-lag approach you said the company was unwilling to produce data to enable you to provide a lead-lag study. Can you explain what you mean by the company was unwilling to produce data?

A Yes. In order to perform a lead-lag study, you need to measure the number of days between the provision of service and the billing for that service and the conversion of those revenues into cash by comparison to the incurrence of expense and the payment of those expenses in case, so it really revolves around the cash in-flows and the cash out-flows, and the timing of those.

And we asked the company for that information; they objected, they said we're not going to provide it to you because we're not required to. We didn't do the study, and so we won't provide you the information.

And then we asked for information with respect to cash budgeting and the company said, oh, we don't perform cash budgets. But that's simply not true. They do. They have to. In order to prepare a forecasted test year, you have to project everything on your balance sheet. That's requires financing, as well --

MR. BUTLER: I'm going to object, again. He made the statement -- I did not follow up on it -- about FPL's not being able to provide that information, and now he's going into a long-winded explanation of something that was certainly not the subject of my cross examination of him.

COMMISSIONER BROWN: I'd have to agree with Mr. Butler on this. Can you move to the next question?

MR. WISEMAN: Sure. In fact, we'll more to the last area.

BY MR. WISEMAN:

Q Staff asked you questions about the storm reserve, and whether the reserve was sufficient to cover the costs of hurricanes at various levels. Do you recall that?

A I do, yes.

Q And in your answer you said that there are other mechanisms available to cover the cost of the storm damage, right?

A Yes, that's correct.

Q Can you explain what those other mechanisms are that you referred to?

A Yes. Well, first of all, there is somewhat in excess of $200 million in the storm damage reserve presently, costs were incurred by FP&L. And then the second thing is that historically this Commission has allowed the utilities to defer any cost above and beyond their storm damage reserve and then to recover those costs in the future.

And since the hurricanes, I believe, in 2005, the Legislature has passed legislation to allow utilities to securitize the storm damage cost, which is a much lower cost form of financing. So there's a lot of mechanisms in place that are much lower cost than funding a storm damage reserve.

MR. WISEMAN: Thank you. That's all my questions.

CHAIRMAN BRISE: Thank you. Exhibits?

MR. WISEMAN: SFHHA would move the admission of Exhibits 320 through 348.

COMMISSIONER BROWN: 320 through 348. Okay, any objections? Seeing none, we will move Exhibits 320 through 348 into the record. There were no other exhibits entered on cross, so would you like to have this witness excused?

(Exhibits 320 through 348 admitted in evidence.)

MR. WISEMAN: Yes. Thank you, Madam Chair.

COMMISSIONER BROWN: Thank you. Have a good day.

THE WITNESS: You, too.

MR. YOUNG: Madam Chairman, I think that concludes South Florida Hospital's case. Next we're on the Federal Executive Agency with witness Gorman and witness

Federal Executive Agency with witness Gorman and witness Stephens. I think witness Steven has been stipulated.

COMMISSIONER BROWN: I think you are correct about Mr. Stephens.

CAPT. MILLER: Thank you, Ms. Commissioner. FEA calls Mr. Michael Gorman.

COMMISSIONER BROWN: Has this witness been sworn?

CAPT. MILLER: No, ma'am. He still needs to be sworn.

Thereupon,

MICHAEL GORMAN

was called as a witness on behalf of Federal Executive Agencies, and having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY CAPT. MILLER:

Q Good afternoon, Mr. Gorman.

A Good afternoon.

Q Can you please state your full name and business address.

A My name is Michael Gorman. My business address is 16690 Swingley Ridge Road, Chesterfield, Missouri.

Q And did you cause to be filed 70 pages of prefiled testimony on behalf of FEA in this case?

A Yes.

Q Do you have any changes that you wish to make to your testimony at this time?

A I do. I have two corrections. One is on page three, on line two. The number 2.08 should be struck; the number 5.08 should be inserted. Second correction is to one of the schedules attached to my testimony. On Exhibit MPG-18, page one, under column two, the word significant should be struck, and the word intermediate should be inserted. That concludes my corrections.

Q Okay. And assuming these corrections, if I were to ask you the same questions that appear in your testimony today, would your answers remain the same?

A They would.

Q Did you also prepare Exhibits MPG-1 through MPG-21?

A Yes.

Q Do you have any changes that you wish to make to these exhibits, other than the one that you've already made?

A That -- no.

CAPT. MILLER: I would now ask that Mr. Gorman's testimony be inserted into the record as though read.

COMMISSIONER BROWN: Without any objections, we will insert Mr. Gorman's prefiled direct testimony into the record as though read.

**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re: Petition for Increase in Rates by Florida Power & Light Company** | ) | **Docket No. 120015-EI** |

## Direct Testimony of Michael P. Gorman

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

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **WHAT IS YOUR OCCUPATION?**

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

Q **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

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

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

**Q WHAT IS THE SUBJECT OF YOUR DIRECT TESTIMONY?**

A I will recommend a fair return on common equity, and overall rate of return for Florida Power and Light Company ("FPL" or "Company").

## SUMMARY

**Q PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATIONS.**

A I recommend the Florida Public Service Commission (the "Commission") award FPL a return on common equity of 9.25%, which is the midpoint of my recommended range of 9.10% to 9.40%, and an overall rate of return of 5.74%. Exhibit MPG-1. I recommend FPL's proposal for a 0.25% return on equity performance adder be rejected.

I also recommend adjustments to the Company's proposed capital structure. My proposed adjustments to the capital structure include modifications to the Company's "Pro Rata" adjustments made to reconcile the amount of capital with the amount of jurisdictional base-rate rate base. I propose an alternative allocation of Pro Rata adjustments. I propose to allocate deferred taxes based on FPL's total plant investment. In comparison, FPL allocates deferred taxes based on total capital. I believe my proposed allocation more accurately allocates deferred tax because predominantly it is tied to plant investment. Hence, my revised allocation of Pro Rata adjustments ensures that customers receive the full benefit of deferred income tax balances as a source of cost-free capital available to support FPL's plant investments.

I also propose adjustments to FPL's estimated embedded debt cost. My adjustments reflect an update to the market interest rates used to calculate the embedded debt cost related to bond issues planned for 2012 and 2013. The effect of this update is to decrease FPL's embedded debt cost from 5.24% down to 2.08%.

My recommended return on equity and proposed capital structure will provide FPL with an opportunity to realize cash flow financial coverages and balance sheet strength that conservatively support FPL's current bond rating. Consequently, my recommended return on equity represents fair compensation for FPL's investment risk, and it will preserve the Company's financial integrity and credit standing.

I will also respond to FPL witness Dr. William E. Avera's proposed return on equity of 11.25% and explain why the Company's proposal to include an additional 25 basis points efficiency adder should be rejected. For the reasons discussed below, Dr. Avera's recommended return on equity is excessive, and the return on equity performance adder should be rejected.

**Q PLEASE SUMMARIZE YOUR RECOMMENDATION CONCERNING FPL'S PROPOSED STEP INCREASE FOR THE CAPE CANAVERAL MODERNIZATION PROJECT.**

A The Company's proposal to remove the Cape Canaveral costs from the 2013 test year to reflect the uncertainty of when it will be placed in-service is reasonable. However, it is not clear to me that the Company has fully removed all costs associated with the Cape Canaveral project. Specifically, the Company does not detail the items included in construction work in progress ("CWIP") that it proposes to include in its test year base-rate rate base. It appears as though some of those CWIP items may include the Cape Canaveral Modernization capital expenditures, prior to the projected in-service date in June 2013.

Therefore, I recommend the Commission require FPL to fully disclose the items that are included in CWIP proposed to be included in the test year rate base. To the extent any of the CWIP items include any component of the Cape Canaveral project costs, then the base-rate rate base should be adjusted to remove all Cape Canaveral costs. By including Cape Canaveral components in test year CWIP included in rate base, and also including a full year revenue requirement on the in-service projected investment cost of Cape Canaveral, FPL will be permitted to recover more than 100% of its investment in the Cape Canaveral project. That would not be reasonable and should be corrected.

## Rate of Return Overview

**Q DOES YOUR RECOMMENDED RETURN ON EQUITY REFLECT FPL'S EXISTING INVESTMENT RISK?**

A Yes. My recommended return on equity reflects fair compensation for FPL's existing investment risk including its regulatory mechanisms used to recover its cost of service. These factors are reflected in FPL's existing bond rating and other risk factors used to select a comparable risk proxy group. If the Commission modified FPL's existing regulatory mechanisms to reduce FPL's investment risk, then any related risk reduction should be considered in determining a fair risk-adjusted return on equity for FPL.

**Q HOW DID YOU ESTIMATE FPL'S CURRENT MARKET COST OF EQUITY?**

A I performed analyses using three Discounted Cash Flow ("DCF") models, a Risk Premium ("RP") study, and a Capital Asset Pricing Model ("CAPM"). These analyses used a proxy group of publicly traded companies that have investment risk similar to FPL. Based on these assessments, I estimate FPL's current market cost of equity to be 9.25%.

**Q HOW DOES YOUR RECOMMENDED RETURN ON EQUITY COMPARE TO FPL'S LAST AUTHORIZED RETURN ON EQUITY?**

A On March 17, 2010, the Commission issued its final order in FPL's rate case (Florida Public Service Commission, Docket No. 080677-EI) and approved a settlement, which included a return on equity of 10.00%.

In awarding a return on equity of 10.00%, the Commission stated that it took into account FPL's proposed construction program, its need to access capital markets under reasonable terms, and its capital structure which included a common equity ratio of total investor capital of 59%, and 56% on a Standard & Poor's ("S&P") adjusted basis.

In FPL's last rate case, the Commission recognized the prevailing economic realities that Florida electric customers face, noting specifically that FPL customers are experiencing economic hardships throughout the state and the need to find an equitable balance between customers and shareholders recognizing the reality of the economic hardships of FPL's customers. (Order at 131 and 132, March 17, 2010).

**Q DOES YOUR RETURN ON EQUITY REFLECT THE SAME TYPE OF BALANCING OF INTERESTS AS OUTLINED BY THE COMMISSION IN AWARDING FPL A RETURN ON EQUITY OF 10.00% IN ITS LAST RATE CASE?**

A Yes. My proposed rate of return considers the ongoing economic hardships for

Florida customers, and the difficult financial markets that utilities, like FPL, continue to operate within. My recommendation also recognizes a significant decline in capital market costs since 2010, the time of FPL's last rate decision. All of these factors necessitate a balance for a fair rate of return reflecting fair compensation in today's marketplace, with the need to mitigate rate increases on FPL's customers.

**Q HAVE CAPITAL MARKET COSTS DECLINED SINCE FPL'S LAST RATE CASE?**

A Yes. The decline of market costs of capital since FPL's last rate case is observable by a comparison of bond yields in this case and those that prevailed during FPL's last case. In Table 1, I show the change in utility bond yields.

**TABLE 1**

**Capital Costs – FPL Rate Cases**

| Description | Current Case[1] | Docket No. 080677-EI | Yield Change |
|---|---|---|---|
| "A" Rated Utility Bond Yields | 4.27% | 5.81% | 1.54% |
| "Baa" Rated Utility Bond Yields | 5.01% | 6.21% | 1.20% |
| 13-Week Period Ending | 06/15/2012 | 03/12/2010 | |

Source:
[1] Exhibit MPG-15, page 1.

As shown in the table above, the current market cost of debt for "A" (by S&P) and "Baa" (by Moody's) rated utility bond yields has decreased in this case relative to FPL's last rate case. The current "A" rated utility bond yield is over 150 basis points lower now than it was in FPL's last rate case. Also, the current "Baa" utility bond yield is 120 basis points lower than during FPL's last rate case.

Utility bond yields have declined by approximately 120 to 150 basis points since FPL's last rate case. This decline in utility bond yields suggests that FPL's cost of capital is lower now than it was in its 2010 rate case.

**Q IS THERE OTHER EVIDENCE OF THE DECLINE IN MARKET COST OF EQUITY SINCE FPL'S LAST RATE CASE?**

A Yes. This is evident from FPL's case itself. In FPL's last rate case, Dr. Avera proposed a return on equity in the range of 12.0% to 13.0%[1] in his direct filing. In its current rate case, FPL is proposing a return on equity of 11.25%, excluding the efficiency adder of 25 basis points. Hence, the Company's evidence acknowledges that capital costs have materially decreased since FPL's last rate case.

## Electric Utility Industry Market Outlook

**Q PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.**

A I begin my estimate of a fair return on equity for FPL by reviewing the market's assessment of electric utility industry investment risk, credit standing and stock price performance in general. I used this information to get a sense of the market's perception of the risk characteristics of electric utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to FPL's utility operations.

[1]Docket No. 080677-EI, Avera Direct at 3. The Company's requested rates were based on a return on equity of 12.5%, which was the midpoint of Dr. Avera's recommended range.

Based on the assessments described below, I find the credit rating outlook of the industry to be strong and supportive of the industry's financial integrity, and electric utilities' stocks have exhibited strong price performance over the last several years.

Based on this review of credit outlooks and stock price performance, I conclude that the market has again embraced the electric utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities.

**Q PLEASE DESCRIBE THE ELECTRIC UTILITIES' CREDIT RATING OUTLOOK.**

A Electric utilities' credit rating outlook has improved over the recent past and is now stable. S&P recently provided an assessment of the credit rating of U.S. electric utilities. S&P's commentary included the following:

> **Solid Industry Fundamentals Support Stable Outlook**
>
> The U.S. electric utility sector performed well through 2011, and found it easier to access the capital markets than did most other corporate issuers.
>
> Investor appetite for electric utility debt remains healthy, and deals have been oversubscribed. Credit fundamentals indicate that most, if not all, electric utilities should continue to have ample access to funding sources and credit. Some firms may issue common stock to partially fund construction spending, which would help to support the capital structure balance. In addition, many utilities are accessing short-term credit markets through

> commercial paper programs at very low rates.[2]

Similarly, Fitch states:

> **Electric Utilities: Stable**
>
> Fitch's Outlook for the electric utility sector in 2012 remains stable. The sector benefits from low interest rates, modest inflationary pressures, open capital markets, and low natural gas and power prices. Fitch expects these conditions to persist into 2013. The favorable funding environment helps to offset any stress that would otherwise result during an extended period of high projected capital investment. Capex is expected to remain elevated, increasing 5%–6% over 2011 levels.[3]

*Value Line* also continues to characterize utility stock investments as a safe haven:

> **Conclusion**
>
> With most of 2011 completed, it seems almost certain that electric utility stocks will have outperformed the broader market averages when the year is over. As of mid-December, the Value Line Utility Average is up slightly, while the Value Line GeometricAverage is down about 14%. Electric utility stocks have long been viewed as a safe haven in volatile markets, due in large part to their generous dividend yields.[4]

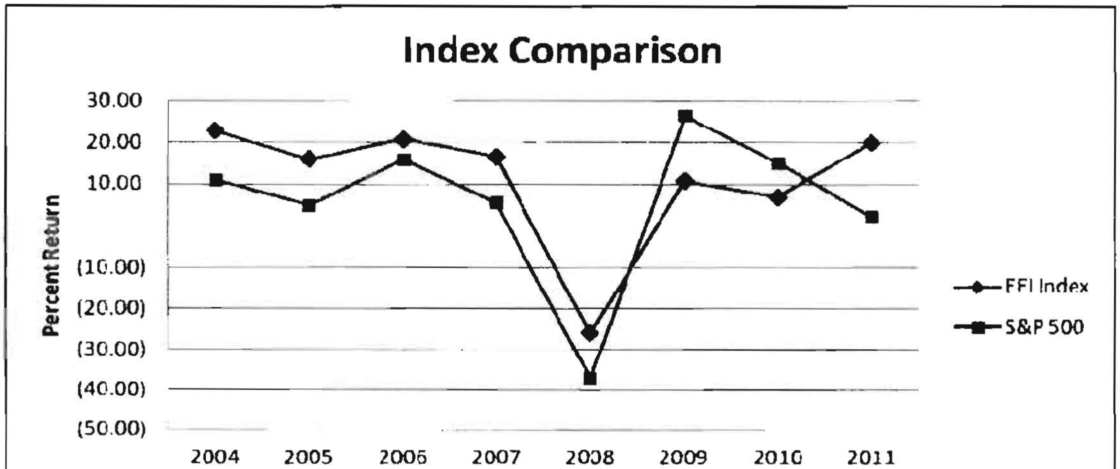
[2] *Standard & Poor's RatingsDirect on the Global Credit Portal*: "Industry Economic And Ratings Outlook: Continued Ratings Stability Expected For U.S. Regulated Electric Utilities In 2012," January 25, 2012 at 4-5.
[3] *FitchRatings*: "2012 Outlook: Utilities, Power, and Gas," December 5, 2011 at 10.
[4] *Value Line Investment Survey*, December 23, 2011 at 901.

The Edison Electric Institute ("EEI") also opined as follows:

> There was little change during 2011 in the industry's long-term outlook. Many regulated utilities are engaged in capital spending programs that should, according to Wall Street analysts, help drive slow but steady earnings growth over the next several years. New EPA regulations may boost capex by 30% in the years ahead, relative to EEI's latest capex survey estimates.[5]

**Q PLEASE DESCRIBE ELECTRIC UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVEN YEARS.**

A As shown in the graph below, the EEI has recorded electric utility stock price performance compared to the market. The EEI data shows that its Electric Utility Index has outperformed the market, with a few exceptions, triggered by the recent state of the economic environment.




**Source: EEI Q4 2011 Stock Performance Financial Update, at Page 1.**

[5] *EEI Q4 2011 Stock Performance* at 1.

During 2009 and 2010, the EEI Index underperformed the market, which is not unusual for stocks that are considered "safe havens" during periods of market turbulence.

In 2011, the EEI Index outperformed the market. EEI states the following:

> **Commentary**
>
> The EEI Index produced a positive 20% return during 2011, its strongest annual gain since 2006, outperforming the broad market after two consecutive years of underperformance as stocks rebounded from the lows reached during 2008 financial crisis.
>
> * * *
>
> The strength of the EEI Index in 2011 is no surprise, highlighting the industry's traditional role as a defensive investment following its reemphasis in recent years of core regulated businesses with slow but predictable earnings growth and steady dividends. In fact, the industry's average dividend yield exceeded 4% during the year, leading that of all other U.S. business sectors.[6]

## FPL Investment Risk

**Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF FPL.**

A The market assessment of FPL's investment risk is best described by credit rating analysts' reports. FPL's current corporate credit ratings from S&P and

[6] *EEI Q4 2011 Stock Performance* at 1 and 4-5.

Moody's are "A-" and "A2," respectively. FPL's current senior secured bond ratings from S&P and Moody's are "Aa3" and "A," respectively.[7]

Specifically, S&P states the following:

> **Rationale**
>
> Standard & Poor's Ratings Services' bases its ratings on Florida Power & Light Co. (FP&L) on the consolidated credit profile of its parent, diversified energy holding company NextEra Energy Inc. <u>The credit fundamentals on its regulated utility side have been among the strongest in the U.S., due primarily to low regulatory risk and an attractive service territory with healthy economic growth and a sound business environment.</u>
>
> * * *
>
> Standard & Poor's Ratings Services' ratings on all NextEra entities reflect the strength of the regulated cash flows from integrated electric utility FP&L, and the diverse and substantial cash-generation capabilities of its unregulated operations at subsidiary NextEra Energy Resources (NER).
>
> * * *
>
> We characterize FP&L's business risk profile as "excellent," NextEra's business risk profile as "strong," and the consolidated financial risk profile as "intermediate" under our criteria.[8]

[7] FPL's response to OPC's 3rd Set of Interrogatories, No. 67, Attachment No. 1.
[8] *Standard & Poor's RatingsDirect on the Global Credit Portal*: "Florida Power & Light Co.," April 24, 2012 at 2 and 3, emphasis added.

Similarly, Moody's states:

> **Summary Rating Rationale**
>
> FPL's ratings are supported by the stability of the utility's regulated cash flows, the geographically diverse and relatively constructive regulatory environments in which it operates, the diversification of its generation portfolio, and solid credit metrics.
>
> * * *
>
> **SUMMARY RATING RATIONALE**
>
> FPL's ratings reflect the stabilization of the political and regulatory environment for investor owned utilities in Florida; the company's strong financial performance, robust cash flow coverage ratios, and relatively low leverage; good cost recovery mechanisms in place; and a large, mainly residential service territory. This service territory has been under significant economic pressure over the last few years, with the company experiencing stagnant residential sales growth in some years, although there have been recent indications that economic conditions are improving. The company's capital expenditure program is large, particularly over the next two years as it adds new gas fired generation and increases capacity at its nuclear plants.
>
> * * *
>
> **Rating Outlook**
>
> The stable rating outlook reflects the regulatory clarity provided by its two year rate settlement and Moody's view that the political and regulatory environment for investor owned utilities in Florida will

not deteriorate further and may improve once the newly constituted FPSC begins to establish a track record. It also reflects the generally strong cost recovery provisions that are in place in the state and our expectation that FPL's financial performance measures and cash flow coverage metrics will remain strong for its rating.[9]

Fitch states:

**Key Rating Drivers**

**Return to Stable Outlook:** Ratings of Florida Power & Light (FPL) were affirmed, and the Rating Outlook was changed to Stable from Negative in May 2011. The new Outlook reflects a more orderly political and regulatory environment for FPL in Florida after a period of political strife and commission turnover. Four of the five current Florida Public Service Commission (FPSC) commissioners were appointed by new Florida Governor Rick Scott, and confirmed by the state's Senate in 2011.

**Rate Stipulation Boosts Cash Flow:** In a contentious general rate case decided in March 17, 2010, FPL received an unfavorable rate decision and challenged some elements. Thereafter, the FPSC approved a settlement agreement (Rate Stipulation) on Dec. 14, 2010, that resolved contested issues from the March 17, 2010, rate order. It allowed FPL to collect revenues for investments in the West County 3 (WC3) power plant via fuel

[9] *Moody's Investors Service Credit Opinion*: "Florida Power & Light Company," April 11, 2011, provided by FPL in response to Staff's 1st PODs (1-22)/Staff's POD No. 5.

savings, contributing to FPL's income and cash flow starting in June 2011.

**Base Rate Freeze:** Numerous fuel and environmental rate adjustments are allowed. FPL can recover investment in nuclear plant capacity upgrades without a base rate case. Recovery of other new utility capital spending in 2011-2013 is subject to FPL's next base rate case, which FPL will likely file in 2012 for effect in January 2013.

**Weak Florida Economy:** FPL's south Florida service territory still has above average unemployment and a weak housing market. However, employment statistics have modestly improved. FPL's inactive accounts and low usage accounts are gradually waning.

**High Utility Capex:** FPL is committed to invest over $3 billion in each of 2011 and 2012, or more than 3x annual depreciation, on projects to reduce reliance on oil, modernize natural gas-fired generation, improve the transmission and distribution systems, and upgrade customer meters.

**Strong Individual Credit Metrics:** Due to low individual debt leverage, FPL's credit metrics well exceed the guidelines for the 'A' rating category and compare favorably with the statistics of 'A' IDR peer utilities.[10]

[10]*FitchRatings Corporates*: "Florida Power & Light Co.," September 7, 2011, provided by FPL in response to Staff's 1st PODs (1-22)/Staff's POD No. 7.

## FPL's Proposed Capital Structure

**Q WHAT CAPITAL STRUCTURE IS THE COMPANY REQUESTING TO USE TO DEVELOP ITS OVERALL RATE OF RETURN FOR ELECTRIC OPERATIONS IN THIS PROCEEDING?**

A FPL's December 2013 forecasted regulatory capital structure, as supported by FPL witness Mr. Moray P. Dewhurst, is shown below in Table 2.

**TABLE 2**

**FPL's Proposed Capital Structure**

| Description | Regulatory Capital Structure (1) | Investors' Capital Structure (2) |
|---|---|---|
| Long-Term Debt | 29.47% | 38.16% |
| Customer Deposits | 2.03% | — |
| Common Equity | 46.03% | 59.62% |
| Short-Term Debt | 1.71% | 2.22% |
| Deferred Income Tax | 20.75% | — |
| Investment Tax Credit | 0.00% | — |
| Total Capital Structure | 100.00% | 100.00% |

Source: MFR Schedule D-1a.

**Q IS FPL'S PROPOSED CAPITAL STRUCTURE REASONABLE?**

A No. FPL's proposal capital structure has an excessive amount of common equity relative to investor capital, and the Company's proposed allocation of its Pro Rata adjustments unjustifiably decrease the amount of deferred taxes supporting the rate base in base rates.

**Q WHY DO YOU BELIEVE THAT FPL'S PROPOSED CAPITAL STRUCTURE CONTAINS AN EXCESSIVE COMMON EQUITY RATIO?**

A FPL's proposed capital structure includes a common equity ratio of 59.62% as a percentage of its total investor capital.[11] This common equity ratio is far in excess of the common equity ratio necessary to support FPL's current bond rating, it is unreasonable in comparison to the proxy group FPL witness Dr. Avera and I used to estimate a return on equity for FPL, and is materially out of line generally with electric utility industry capital structures used to set rates.

For credit rating purposes, FPL's common equity ratio of 59% translates to an S&P adjusted ratio of 56.3% (Exhibit WEA-14). This ratio is far higher than the 40% to 50% common equity ratio or 60% to 40% long-term debt ratio that will support an investment grade bond rating for a utility with an "Excellent" business profile score (FPL's rating) and an "Intermediate" to "Aggressive" financial profile generally consistent with industry averages. For example, in a 2010 report, S&P stated that the median utility industry average adjusted debt ratio was 57.3%. This implies a common equity ratio of approximately 42.7%. FPL's adjusted debt ratio of 43.7% is substantially beneath this industry average. I would note also that the utilities included in that industry median typically have bond ratings ranging from "BBB" all the way up to "AA."[12]

The common equity ratio of 59% is also significantly higher than the proxy group average common equity ratio of 48.4% used by FPL witness Dr. Avera and me to measure FPL's fair return on common equity in this proceeding. FPL's "Excellent" business profile score from S&P, and its financial risk that is lower

[11]Common equity, long-term debt and short-term debt.
[12]Standard & Poor's Global Credit Portal RatingsDirect Credit Stats: Multi Utilities U.S. – August 24, 2011.

than that of the proxy group, suggest that FPL is not managing its capital structure to minimize its cost of capital consistent with its peer utility companies.

FPL's 59% common equity ratio is also excessive in comparison to the capital structure typically awarded by regulatory commissions for electric utilities. On an industry average basis, over the last five years, electric utilities' authorized returns on equity have generally been awarded in combination with capital structures composed of common equity of around 48%. By virtually all measures, FPL's current cost of capital is substantially overstated.

**Q IS CAPITAL STRUCTURE MANAGEMENT AN IMPORTANT OBJECTIVE FOR A UTILITY?**

A Yes. A utility managing its capital structure is important to balance its obligations to minimize its cost of capital, while at the same time support its financial integrity and access to capital. This balance requires a utility to manage its capital structure to maintain a reasonable balance of common equity and debt such that cost of capital is minimized and its credit rating is preserved.

A capital structure too heavily weighted with common equity will unnecessarily increase its overall cost of capital, because common equity is the most expensive form of capital. For example, an authorized return on equity of 9.0%, adjusted for income tax has a revenue requirement cost of 14.5%.[13] Conversely, current debt interest rates are around 4.5%, and the interest expense is tax deductible. Therefore, the revenue requirement cost of debt capital is 4.5%. As such, common equity capital is approximately three times more expensive than debt capital. Conversely, a capital structure too heavily

[13] $9.0\% * \frac{(1)}{(1 - \text{Tax Rate})}$ (assuming a 38% composite tax rate)

weighted with debt will result in an increase in its financial risk and likely drive up its overall cost of capital.

**Q WHY DO YOU BELIEVE THAT FPL'S PROPOSED CAPITAL STRUCTURE MISALLOCATES DEFERRED TAXES?**

A FPL proposes to allocate the Pro Rata adjustments in proportion to its capital component weights of total capital. This in effect spreads deferred taxes on the basis of total capital. This is inappropriate because deferred taxes should be allocated on rate base, or plant in-service – not total capital.

**Q ARE YOU PROPOSING ANY ADJUSTMENTS TO THE ALLOCATION OF THE PRO RATA ADJUSTMENTS?**

A Yes. Pro Rata adjustments essentially synchronize the capital structure used to develop the overall rate of return with the amount of retail rate base supporting base rates. As a means of properly gauging the amount of total deferred taxes that should be recognized in supporting base-rate rate base, I propose to allocate deferred taxes to the base-rate rate base using an allocator of base-rate plant in-service to total FPL plant in-service. I used plant in-service as a proxy for rate base since total rate base data is not available and deferred tax balance is largely created by depreciation timing differences (tax versus book) on plant in-service.

My modified allocation of Pro Rata adjustments is developed on my Exhibit MPG-1, page 2. As shown on this exhibit, I developed a base rate allocator from the percentage of retail plant in-service (included in base rates) as a percentage of total plant in-service. I propose to allocate 86.36% of total deferred taxes to rate base recovered in the FPL base rates. The remaining amount of Pro Rata adjustments would then be spread equitably across all investor capital components: common equity, long-term debt and short-term debt, and customer deposits.

**Q ARE YOU PROPOSING ANY ADJUSTMENTS TO MODIFY FPL'S EXCESSIVE COMMON EQUITY RATIO?**

A No, although an adjustment would be appropriate. The Commission already addressed FPL's excessive common equity ratio in its last rate case (Order at pages 114-119). Therefore, I simply will reflect the excessive cost of its capital structure and the fact that FPL has below industry average and lower financial risk than the proxy group in my development of a fair return on equity for FPL in this proceeding.

**Q WHAT IS YOUR PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?**

A My proposed capital structure is shown below in Table 3.

**TABLE 3**

**Proposed Capital Structure**

| Description | Percent of Total Capital |
|---|---|
| Long-Term Debt | 29.16% |
| Customer Deposits | 2.41% |
| Common Equity | 44.08% |
| Short-Term Debt | 1.64% |
| Deferred Income Tax | 22.70% |
| Investment Tax Credit | 0.00% |
| Total Capital Structure | 100.00% |

Source: Exhibit MPG-1, page 1.

## Embedded Cost of Debt

**Q DID FPL INCLUDE PROJECTED NEW BOND ISSUANCE IN ITS EMBEDDED COST OF DEBT ESTIMATE?**

A Yes. Company witness Dewhurst develops FPL's proposed cost of debt of 5.24% on Schedule D-4a. He includes the following projected debt issuances:

- 4.85% $400 million 30-year debt with issuance, April 2012;
- 5.05% $250 million 30-year debt with issuance, December 2012; and
- 5.09% $750 million 30-year debt with issuance, February 2013.

**Q IS FPL'S PROJECTED PRICING FOR THESE BOND ISSUES REASONABLE?**

A No. The Company's debt prospectus (May 15, 2012) states that FPL issued a 30-year $600 million bond at a 4.05% coupon rate. FPL's rate case projected interest rates for new bond issuances are much higher than this actual recent bond interest rate.

**Q ARE YOU PROPOSING TO ADJUST FPL'S EMBEDDED DEBT COST ESTIMATE?**

A Yes. I repriced the Company's projected debt issuance in April 2012 to reflect the actual issuance amount and coupon rate for all projected bond issuance. My adjusted debt cost is developed on my Exhibit MPG-2. As shown on my Exhibit MPG-2, I propose to reduce FPL's estimated embedded cost of long-term debt to 5.08% from 5.24%.

**Q DO YOU HAVE ANY ADDITIONAL COMMENTS RELATED TO FPL COSTS OF CAPITAL?**

A Yes. FPL incorrectly calculated the cost of the investment tax credit ("ITC") included in its regulatory capital structure. The Company did not include the short-term debt in the cost of ITC. I recommend setting the ITC cost at the weighted average cost of all investor capital, including short-term debt.

**Q WILL YOUR PROPOSED CAPITAL STRUCTURE SUPPORT FPL'S FINANCIAL INTEGRITY AND CREDIT RATING?**

A Yes. As I will discuss later in my testimony, my proposed capital structure is consistent with FPL's current credit rating and will support FPL's financial integrity.

## Return on Equity

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

A A utility's cost of common equity is the return investors require on an investment in the utility. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

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

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: *Bluefield Water Works & Improvement Co. v. Public Serv. Commission of West Virginia,* 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

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

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

A I have used several models based on financial theory to estimate FPL's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using analyst growth data; (2) a sustainable growth DCF model; (3) a multi-stage growth DCF model; (4) an RP model; and (5) a CAPM. I have applied these models to a group of publicly traded utilities that I have determined share investment risk similar to FPL's.

**Q HOW DID YOU SELECT A UTILITY PROXY GROUP SIMILAR IN INVESTMENT RISK TO FPL TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY?**

A I relied on the same utility proxy group used by FPL witness Dr. Avera to estimate FPL's return on equity, except I excluded ITC Holdings Inc. I excluded ITC Holdings because it is involved in merger and acquisition ("M&A") related activities. It is appropriate to exclude companies in M&A activity because the market price may not reflect the earnings outlook of the individual company, but may be impacted by the expectation of mergers or acquisitions which could enhance future earnings outside of the security analysts' outlooks for the company. I would note, that it is standard to exclude companies involved in M&A activity, and even Dr. Avera claims to have excluded these companies. However, for some reason he did not exclude ITC Holdings Inc. which should have been excluded under his own proxy group selection criteria. (Avera Direct at 33-34).

**Q HOW DOES THE PROXY GROUP INVESTMENT RISK COMPARE TO FPL'S INVESTMENT RISK?**

A The proxy group is shown on Exhibit MPG-3. This proxy group has an average credit rating from S&P of "A-," which is identical to S&P's credit rating for FPL. The proxy group's credit rating from Moody's is "A2," which is also identical to FPL's credit rating from Moody's of "A2." The proxy group has comparable investment risk to FPL.

The proxy group has an average common equity ratio of 45.6% (including short-term debt) from *AUS Utility Reports* ("AUS") and 48.4% (excluding short-term debt) from *Value Line* in 2011. The proxy group's common equity ratio is lower than FPL's proposed common equity ratio, which suggests it has greater financial risk than FPL.

I also compared FPL's business risk to the business risk of the proxy group based on S&P's ranking methodology. FPL has an S&P business risk profile of "Excellent," which is identical to the S&P business risk profile of the proxy group. The S&P business risk profile score indicates that FPL's business risk is comparable to that of the proxy group.[14]

Based on these proxy group selection criteria, I believe that my proxy group reasonably approximates the investment risk of FPL, albeit the group has greater financial risk than FPL.

## Discounted Cash Flow Model

**Q PLEASE DESCRIBE THE DCF MODEL.**

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

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

$P_0$ = Current stock price

D = Dividends in periods 1 - $\infty$

K = Investor's required return

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

[14]S&P ranks the business risk of a utility company as part of its corporate credit rating review. S&P considers total investment risk in assigning bond ratings to issuers, including utility companies. In analyzing total investment risk, S&P considers both the business risk and the financial risk of a corporate entity, including a utility company. S&P's business risk profile score is based on a six-notch credit rating starting with "Vulnerable" (highest risk) to "Excellent" (lowest risk). The business risk of most utility companies falls within the lowest risk category, "Excellent," or the category one notch lower (more risk), "Strong." *Standard & Poor's:* "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

$K = D_1/P_0 + G$ (Equation 2)

$K$ = Investor's required return

$D_1$ = Dividend in first year

$P_0$ = Current stock price

$G$ = Expected constant dividend growth rate

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

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

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

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

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ended June 15, 2012. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

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

**Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?**

A I used the most recently paid quarterly dividend, as reported in *The Value Line Investment Survey.*[15] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the $D_1$ factor for use in Equation 2 above.

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

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

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[16] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence observable stock prices than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of

[15]*The Value Line Investment Survey*, March 23, May 4, and May 25, 2012.
[16]See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

analysts' growth rate estimates from three sources: Zacks, SNL Financial, and Reuters. All such projections were available on June 17, 2012, and all were reported online.

Each consensus growth rate projection is based on a survey of security analysts. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is more representative of general market expectations. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

**Q WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?**

A The growth rates I used in my DCF analysis are shown in Exhibit MPG-4. The average growth rate for my proxy group is 5.04%.

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

A As shown in Exhibit MPG-5, the average and median constant growth DCF returns for my proxy group are 9.29% and 9.20%, respectively.

**Q DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?**

A Yes. The three- to five-year growth rates are slightly higher but still in line with the long-term sustainable growth rate. Therefore, I believe my constant growth DCF analysis using analysts' three- to five-year growth rates reflects reasonable growth outlooks and the DCF results are also reasonable. Nevertheless, I consider other DCF methodologies in order to enhance the information available to accurately estimate FPL's current market return on common equity.

## Sustainable Growth DCF

**Q PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.**

A A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment, plus the growth realized by selling additional shares at market prices above book value. Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment. The reinvested earnings and above book value accretion increase the earnings base (rate base), and support sustainable long-term growth.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings. The payout ratios of the proxy group are shown on my Exhibit MPG-6.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market to book ratio and on *Value Line's* three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit MPG-7, page 1, the average sustainable growth rate for the proxy group using this internal growth rate model is 5.47%.

Q **WHAT STOCK PRICE AND DIVIDENDS DID YOU USE IN YOUR SUSTAINABLE LONG-TERM GROWTH DCF STUDY?**

A I used the same stock prices and dividends growth in my sustainable growth DCF model as I used in my constant growth DCF model discussed above.

Q **WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?**

A A DCF estimate based on these sustainable growth rates is developed in Exhibit MPG-8. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results of 9.73% and 10.10%, respectively.

## Multi-Stage Growth DCF Model

Q **HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?**

A Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

**Q WHEN DO YOU BELIEVE SHORT-TERM GROWTH RATES CHANGE OVER TIME?**

A Short-term growth rates, or the three- to five-year growth rates projected by the analysts, change when utility earnings change over time. Utility companies typically go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which accelerates their earnings growth during a major construction period. Once a major construction cycle is completed or levels off, growth in the utility rate base slows, and its earnings slow from an abnormally high short-term growth rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because it is adding to a larger rate base, and the utility has limited human and capital resources to continue to expand its construction program. Hence, the three- to five-year growth rate projection should be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment in the industry.

**Q WHY CAN'T A UTILITY'S ELEVATED SHORT-TERM GROWTH RATE OUTLOOKS BE SUSTAINED EVEN IF ITS CAPITAL PROGRAM CONTINUES OVER AN INDEFINITE PERIOD OF TIME?**

A Because the growth rate will slow over time, even if the utility's capital program remains at an elevated level. This is illustrated in Table 4 below. Consider a hypothetical company with a beginning plant-in-service of $1 million and an elevated capital expenditure program of $100,000 (10% of total capital). Capital expenditures stay elevated but also grow at the rate of inflation of 2% over the next 10 years. This Company has depreciation expense based on a rate of gross plant of 3.0%.

In this example, the first year, the capital expenditures less depreciation expense will grow plant-in-service from $1 million up to $1,070,000 – a 7% plant growth. In this example, earnings in the year would begin at an assumed 10% rate of return on investment, or $103,500. This represents a 10% return on average plant investment for the year. Now assume that the capital improvement program continues, and plant-in-service increases from the initial $1 million up to $1,139,900 by the end of year 2. In this second year, earnings would increase to $110,495, a 6.8% growth in earnings relative to year 1. Each year, the embedded plant-in-service increases by capital improvements less depreciation expense. As a result, the growth in earnings slows because a percent change in plant-in-service starts to slow as the beginning of the year plant-in-service number increases. That is, the denominator in the growth equation increases with a relatively flat but elevated level of capital improvements resulting in a decreasing growth in earnings. With this continued level of elevated capital improvement offset by depreciation expense, the growth rate of earnings starts at around 6.8% in the beginning of the growth period, declines to around 5.3% after five years of growth, and further declines to around 4.2% after 10 years of elevated capital investment spending. Hence, while the company maintains an elevated level of capital spending throughout the forecast period, the earnings growth rate nevertheless declines from 6.8% at the beginning of the spending period, down to 4.2% after 10 years of elevated capital spending. Again, this occurs because the denominator in the growth equation increases as plant investment is made and plant-in-service increases. As a result, elevated capital expenditures have a lower growth impact on a larger capital base after years of elevated capital spending relative to the beginning of the capital spending program.

**TABLE 4**

**Annual Growth Outlook**

| Year | Beginning of Year Plant-in-Service (1) | Capital Improvement (2) | Deprec. Expense (3) | End of Year Plant-in-Service (4) | Avg Year Plant (5) | ROE (6) | Earnings (7) | Annual Earnings Growth Rate (8) |
|---|---|---|---|---|---|---|---|---|
| 0 | $1,000,000 | $100,000 | $30,000 | $1,070,000 | $1,035,000 | 10.0% | $103,500 | |
| 1 | $1,070,000 | $102,000 | $32,100 | $1,139,900 | $1,104,950 | 10.0% | $110,495 | 6.8% |
| 2 | $1,139,900 | $104,040 | $34,197 | $1,209,743 | $1,174,822 | 10.0% | $117,482 | 6.3% |
| 3 | $1,209,743 | $106,121 | $36,292 | $1,279,572 | $1,244,657 | 10.0% | $124,466 | 5.9% |
| 4 | $1,279,572 | $108,243 | $38,387 | $1,349,428 | $1,314,500 | 10.0% | $131,450 | 5.6% |
| 5 | $1,349,428 | $110,408 | $40,483 | $1,419,353 | $1,384,390 | 10.0% | $138,439 | 5.3% |
| 6 | $1,419,353 | $112,616 | $42,581 | $1,489,388 | $1,454,371 | 10.0% | $145,437 | 5.1% |
| 7 | $1,489,388 | $114,869 | $44,682 | $1,559,575 | $1,524,482 | 10.0% | $152,448 | 4.8% |
| 8 | $1,559,575 | $117,166 | $46,787 | $1,629,954 | $1,594,765 | 10.0% | $159,476 | 4.6% |
| 9 | $1,629,954 | $119,509 | $48,899 | $1,700,565 | $1,665,259 | 10.0% | $166,526 | 4.4% |
| 10 | $1,700,565 | $121,899 | $51,017 | $1,771,447 | $1,736,006 | 10.0% | $173,601 | 4.2% |

Notes:
Column 2: Escalation Rate 2.00%.
Column 3: Depr Rate 3.00%.
Column 4 = Column 1 plus Column 2 less Column 3.
Column 5 = (Column 1 + Column 4)/2.
Column 7 = Column 5 * Column 6.
Column 8 = Column 7 N ÷ Column 7 N-1 (N is the Year) less 1.

**Q IS THE USE OF A MULTI-STAGE DCF MODEL SUPPORTED IN ACADEMIC AND INDUSTRY LITERATURE?**

A. Yes. In fact, a widely cited publication used to support Dr. Avera's testimony makes this quite clear. In his book *New Regulatory Finance*, Dr. Morin states the following:

> Dividends need not be, and probably are not, constant from period to period. Moreover, there are circumstances where the standard DCF model cannot be used to assess investor return requirements. For example, if a utility company is in the process of altering its dividend payout policy and dividends are not expected to grow at the same rate as earnings during the transition period, the standard DCF model is inapplicable. This is because the expected growth in stock price has to be different from that of dividends, earnings, and book value if the market price is to converge toward book value.
>
> * * *
>
> A Non-Constant Growth DCF model is appropriate whenever the growth rate is expected to change, and the only way to produce a change in the forecast payout ratio is by introducing an intermediate growth rate that is different from the long-term growth rate, as in the previous example.[17]

**Q PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.**

A The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

[17] *New Regulatory Finance*, Roger A. Morin, PhD, 2006 Public Utilities Reports, Inc., Vienna, Virginia, pp. 264 and 267.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the United States Gross Domestic Product ("U.S. GDP") growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP of 4.9%.

**Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE GROWTH RATE FOR A UTILITY?**

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the overall economy. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas. The Energy Information Administration ("EIA") has observed that utility sales growth is less than U.S. GDP growth, as shown in Exhibit MPG-9. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative, albeit overstated, proxy for electric utility sales growth, rate base growth, and earnings growth. Therefore, GDP growth is a conservative proxy for the highest sustainable long-term growth rate of a utility.

**Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?**

A Yes. This concept is supported in both published analyst literature and academic work. Specifically, in a textbook entitled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[18]

**Q HOW DID YOU DETERMINE THE CONSENSUS REASONABLE, SUSTAINABLE LONG-TERM GROWTH RATE?**

A I relied on the consensus analysts' projections of long-term GDP growth. *The Blue Chip Financial Forecasts* publishes consensus economists' GDP growth projections twice a year. Based on its latest issue, the consensus economists' published GDP growth rate outlook is 5.1% to 4.7% over the next 10 years.[19]

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rate of 4.9%, as published by *Blue Chip Financial Forecasts,* as an estimate of long-term sustainable growth. *Blue Chip*

[18] "Fundamentals of Financial Management," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298.
[19] *Blue Chip Financial Forecasts*, June 1, 2012 at 14.

*Financial Forecasts'* projections provide real GDP growth projections of 2.8% and 2.5%, and GDP inflation of 2.2% and 2.1%[20] over the 5-year and 10-year projection periods, respectively. This consensus GDP growth forecast represents the most likely views of market participants because it is based on published consensus economist projections.

**Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?**

A Yes. The U.S. EIA in its Annual Energy Outlook projects the real GDP out until 2035. In its 2011 Annual Report, the EIA projects real GDP through 2035 to be in the range of 2.1% to 3.2%, with a midpoint or reference case of 2.7%.[21]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth of 3.3% to 2.4% during the next five and 10 years, respectively, with GDP price inflation of 1.9% to 2.0%.[22] The CBO's real GDP projections are higher than the consensus but its GDP inflation is lower than the consensus economists.

The real GDP and nominal GDP growth projections made by the U.S. EIA and those made by the CBO support the use of the consensus analyst 5-year and 10-year projected GDP growth outlooks as a reasonable market assessment of long-term prospective GDP growth.

[20]GDP growth is the product of real and inflation GDP growth.
[21]*DOE/EIA Annual Energy Outlook 2011 With Projections to 2035*, April 2011 at 58.
[22]*CBO: The Budget and Economic Outlook: Fiscal Years 2012 to 2022*, January 2012.

**Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?**

A I relied on the same 13-week stock price and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The transition period begins in year 6 and ends in year 10. For the long-term sustainable growth rate starting in year 11, I used 4.9%, the average of the consensus economists' 5-year and 10-year projected nominal GDP growth rates.

**Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?**

A As shown in Exhibit MPG-10, the average and median DCF returns on equity for my proxy group are 9.18% and 9.19%, respectively.

**Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.**

A The results from my DCF analyses are summarized in Table 5 below:

**TABLE 5**

**Summary of DCF Results**

| Description | Estimates |
|---|---|
| Constant Growth DCF Model (Analysts' Growth) | 9.29% |
| Constant Growth DCF Model (Sustainable Growth) | 9.73% |
| Multi-Stage Growth DCF Model | 9.18% |
| **Average** | **9.40%** |

## Risk Premium Model

**Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.**

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

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through 2011. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields. I selected the period 1986 through 2011 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit MPG-11, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit MPG-12, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.23%. Of the 26 observations, 20 indicated risk premiums fall in the range of 4.41% to 6.13%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown in Exhibit MPG-13, the average indicated equity risk premium over contemporary Moody's utility bond yields was 3.81% over the period 1986 through 2011. The indicated equity risk premium estimates based on this analysis primarily fall in the range of 3.03% to 4.62% over this time period.

**Q DO YOU BELIEVE THAT THESE EQUITY RISK PREMIUM ESTIMATES ARE BASED ON A TIME PERIOD THAT IS TOO LONG OR TOO SHORT TO DRAW ACCURATE RESULTS CONCERNING CONTEMPORARY MARKET CONDITIONS?**

A No. Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data. Conversely, studies have recommended that use of "actual achieved return data" should be based on very long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. However, these short-term abnormal actual returns would be smoothed over time and the achieved actual returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual returns, and, thus, need not encompass very long time periods.

**Q BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE FPL'S COST OF COMMON EQUITY IN THIS PROCEEDING?**

A The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit MPG-14. On that exhibit, I show the yield spread between utility bonds and Treasury bonds over the last 32 years. As shown in this exhibit, the 2008 utility bond yield spreads over Treasury bonds for "A" rated and "Baa" rated utility bonds are 2.25% and 2.97%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for 2009 are 1.97% and 2.99%, respectively. In 2010, these spreads declined to 1.21% and 1.71%, respectively. In 2011, they declined further to 1.13% and 1.65%, respectively. These utility bond yield spreads over Treasury bond yields are now lower than the 32-year average spreads of 1.58% and 1.98%, respectively.

A current 13-week average "A" rated utility bond yield of 4.27%, when compared to the current Treasury bond yield of 3.00% as shown in Exhibit MPG-15, page 1 implies a yield spread of around 1.27%. This current utility bond yield spread is lower than the 32-year average spread for "A" utility bonds of 1.58%. The current spread for the "Baa" utility yields of 2.01% is slightly higher, albeit comparable to the 32-year average spread of 1.98%.

These utility bond yield spreads are clear evidence that the market considers the utility industry to be a relatively low risk investment and demonstrates that utilities continue to have strong access to capital.

**Q HOW DID YOU ESTIMATE FPL'S COST OF COMMON EQUITY WITH THIS RISK PREMIUM MODEL?**

A I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. The 13-week average 30-year Treasury bond yield, ending June 15, 2012 was 3.00%, as shown in Exhibit MPG-15, page 1. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 3.70%, and a 10-year Treasury bond yield to be 2.70%.[23] Using the projected

[23] *Blue Chip Financial Forecasts*, June 1, 2012 at 2.

30-year bond yield of 3.70%, and a Treasury bond risk premium of 4.41% to 6.13%, as developed above, produces an estimated common equity return in the range of 8.11% (3.70% + 4.41%) to 9.83% (3.70% + 6.13%). I recommend an equity risk premium of 9.26%, rounded to 9.30%. This estimate is based on giving two-thirds weight to my high-end risk premium estimate of 9.83%, and one-third weight to my low-end risk premium estimate of 8.11%. I believe this weighting is appropriate given the large yield spreads between Treasury bond and utility bond yields.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "A" rated utility bonds for the period ending June 15, 2012 of 4.27%. Adding the utility equity risk premium of 3.03% to 4.62%, as developed above, to an "A" rated bond yield of 4.27%, produces a cost of equity in the range of 7.30% (4.27% + 3.03%) to 8.89% (4.27% + 4.62%). Again, recognizing the large Treasury bond yield to utility bond yield spreads, I recommend a risk premium of 8.89%, rounded to 8.90%, based on this risk premium study.

My risk premium analyses produce a return estimate in the range of 8.90% to 9.30%, with a midpoint estimate of 9.10%.

## <u>Capital Asset Pricing Model ("CAPM")</u>

**Q PLEASE DESCRIBE THE CAPM.**

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

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

$R_i$ = Required return for stock i

$R_f$ = Risk-free rate

$R_m$ = Expected return for the market portfolio

$B_i$ = Beta - Measure of the risk for stock

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

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

Q **PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.**

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

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

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.70%.[24] The current 30-year Treasury bond yield is 3.00%. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.70% for my CAPM analysis.

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

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

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

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[24] *Blue Chip Financial Forecasts*, June 1, 2012 at 2.

**Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?**

A As shown in Exhibit MPG-16, the proxy group average *Value Line* beta estimate is 0.70.

**Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?**

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

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

Morningstar's *Stocks, Bonds, Bills and Inflation 2012 Classic Yearbook* publication estimates the historical arithmetic average real market return over the period 1926 to 2011 as 8.6%.[25] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.4%.[26] Using these estimates, the expected market return is 11.21%.[27] The market risk premium then is the difference between the 11.21% expected market return, and my 3.70% risk-free rate estimate, or approximately 7.50%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2012 Classic Yearbook*. Over the period 1926 through 2011, Morningstar's study estimated that the arithmetic

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[25] *Morningstar, Inc. Ibbotson SBBI 2012 Classic Yearbook* at 84.
[26] *Blue Chip Financial Forecasts*, June 1, 2012 at 2.
[27] $\{ [ (1 + 0.086) * (1 + 0.024) ] - 1 \} * 100$.

average of the achieved total return on the S&P 500 was 11.8%,[28] and the total return on long-term Treasury bonds was 6.1%.[29] The indicated market risk premium is 5.7% (11.8% - 6.1% = 5.7%). The average of my market risk premium estimates (7.5% to 5.7%) is 6.6%.

Q **HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY MORNINGSTAR?**

A Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 5.9% to 6.6%. My market risk premium falls in the range of 5.7% to 7.5%. My average market risk premium of 6.6% is at the high end of Morningstar's range.

Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2011. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate. I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury

[28] *Morningstar, Inc. Ibbotson SBBI 2012 Classic Yearbook* at 83.
[29] *Id.*

bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's range is based on several methodologies. First, Morningstar estimates a market risk premium of 6.6% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange (the "NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.4% and not 6.6%. Third, if only the two deciles of the largest companies included in the NYSE were considered, the market risk premium would be 5.9%.[30]

Finally, Morningstar found that the 6.6% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable. Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Morningstar published a long-horizon supply-side market risk premium of 6.1%.[31]

Q **WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?**

A As shown in Exhibit MPG-17, based on my and Morningstar's high-end market risk premium of 6.6%, a risk-free rate of 3.7%, and a beta of 0.70, my CAPM analysis produces a return of 8.32%.

[30]Morningstar observes that the S&P 500 and the NYSE Decile 1-2 are both large capitalization benchmarks. *Morningstar, Inc. Ibbotson SBBI 2012 Valuation Yearbook* at 54.
[31]*Id.* at 66.

## Return on Equity Summary

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

A Based on my analyses, I estimate FPL's current market cost of equity to be 9.25%.

**TABLE 6**

**Return on Common Equity Summary**

| Description | Results |
|---|---|
| DCF | 9.40% |
| Risk Premium | 9.10% |
| CAPM | 8.32% |

My recommended return on common equity of 9.25% is at the midpoint of my recommended range of 9.10% to 9.40%. The high-end of my recommended range is based on my DCF estimate and the low-end is based on my Risk Premium estimate.

## Financial Integrity

**Q WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR FPL?**

A Yes. I have reached this conclusion by comparing the key credit rating financial ratios for FPL, at my proposed return on equity and capital structure, to S&P's benchmark financial ratios using S&P's new credit metric ranges.

**Q PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.**

A S&P publishes a matrix of financial ratios that correspond to its assessment of the business risk of the utility company and related bond rating. On May 27, 2009, S&P expanded its matrix criteria[32] by including additional business and financial risk categories. Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most electric utilities have a business risk profile of "Excellent" or "Strong." The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the electric utilities have a financial risk profile of "Aggressive." FPL has an "Excellent" business risk profile and a "Significant" financial risk profile.

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

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

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The three primary financial ratio benchmarks it relies on in its credit rating process include: (1) Total Debt to

[32]S&P updated its original 2007 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

Total Capital; (2) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (3) Funds From Operations ("FFO") to Total Debt.

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

A I calculated each of S&P's financial ratios based on FPL's cost of service for its Florida jurisdictional electric operations. While S&P would normally look at total consolidated FPL financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in FPL's Florida regulated utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and FPL's financial integrity.

**Q DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT ("OBSD")?**

A Yes. In its most recent report, S&P estimated off-balance sheet debt equivalents of $922 million attributed to FPL's purchased power agreements ("PPA").

**Q PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS FOR FPL.**

A The S&P financial metric calculations for FPL at a 9.25% return are developed on Exhibit MPG-18, page 1.

FPL's adjusted total debt ratio is approximately 44%. This is at the high end of the "Intermediate" utility guideline range of 35% to 45%. This total debt ratio will support an investment grade bond rating.

As shown on Exhibit MPG-18, page 1, column 1, based on an equity return of 9.25%, FPL will be provided an opportunity to produce a debt to EBITDA ratio of 2.9x. This is at the high end of S&P's "Intermediate" guideline range of 2.0x to 3.0x.[33] This ratio also supports an investment grade credit rating.

Finally, FPL's retail operations FFO to total debt coverage at a 9.25% equity return would be 25%, which is within the "Significant" metric guideline range of 20% to 30%. The FFO/total debt ratio will support an investment grade bond rating.

At my recommended return on equity of 9.25% and proposed capital structure, FPL's financial credit metrics are supportive of its current investment grade utility bond rating.

## RESPONSE TO FPL WITNESS DR. WILLIAM AVERA

**Q WHAT IS FPL'S RETURN ON EQUITY RECOMMENDATION?**

A FPL's rate of return witness, Dr. Avera, recommends a return on equity of 11.25%, which is the midpoint of his recommended range of 10.25% to 12.25% after his 15 basis point adjustment for flotation costs. (Avera Direct at 80). He also supports FPL's 25 basis points efficiency adder request (Avera Direct at 81).

[33] *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009 at 4.

**Q HOW DID DR. AVERA DEVELOP HIS RETURN ON EQUITY RANGE?**

A Dr. Avera developed his return on equity recommendation by applying the DCF model to a utility proxy group and a non-utility proxy group. He also used a CAPM, RP and Comparable Earnings Model ("CEM") to support his recommendation. Dr. Avera arrived at his recommendations by reviewing FPL's business operations, market conditions, and utility industry trends at the time of his analysis.

**Q PLEASE SUMMARIZE DR. AVERA'S PROPOSED RETURN ON EQUITY FOR FPL.**

A As shown below in Table 7, his analyses produce a return on equity in the range of 9.6% to 12.3%. He then included a flotation adder of 15 basis points, and concluded that a reasonable return on equity for FPL is in the range of 10.25% to 12.25%, with a midpoint of 11.25%. However, as I will discuss in more detail below, making reasonable adjustments to Dr. Avera's DCF, CAPM and RP studies reduces his return on equity estimate for FPL to the range of 9.0% to 9.5%. Dr. Avera's flotation cost return on equity adder should be rejected.

**TABLE 7**

**Dr. Avera's Return on Equity Analysis**

| Model | Avera Proposed | Adjusted |
|---|---|---|
| DCF (Utility) | 9.6% - 10.3% | 9.5% |
| DCF (Non-Utility) | 11.5% - 12.3% | Reject |
| CAPM (Current) | | |
| Unadjusted | 10.4% | 7.6% |
| Size Adjusted | 11.2% | Reject |
| CAPM (Projected) | | |
| Unadjusted | 10.8% | 8.9% |
| Size Adjusted | 11.6% | Reject |
| Risk Premium | | |
| Current | 9.6% | 8.6% |
| Projected | 10.4% | Reject |
| Expected Earnings | | |
| 2014-16 | 10.5% | Reject |
| Utility Proxy Group | 12.0% | Reject |
| Recommended ROE* | 11.25% | 9.0% - 9.5% |
| Efficiency Adder | 0.25% | – |
| Adjusted Recommended ROE | 11.50% | |

Source: Exhibit WEA-13, page 1 of 1.

*The recommended ROE includes a flotation cost adder of 15 basis points.

Q **DO YOU HAVE COMMENTS RELATED TO THE RESULTS PRESENTED IN DR. AVERA'S DIRECT TESTIMONY?**

A Yes. Dr. Avera's results are unreliable because they are derived from stale data. His DCF results reflect stock prices, dividends and growth rates as of November 2011. Similarly, his CAPM and risk premium studies reflect Treasury and utility yield as of December 2011. Therefore, Dr. Avera's studies should be rejected because they do not reflect the current market environment.

**Q WHY IS DR. AVERA'S FLOTATION COST ADJUSTMENT FLAWED?**

A Dr. Avera's proposed 0.15% flotation cost adjustment is not based on the recovery of prudent and reasonable FPL flotation cost expenses. Rather, as discussed at pages 70-72 of Dr. Avera's direct testimony, he derives a flotation cost adjustment based on generic cost information which followed a study from published literature. Because he does not show that his adjustment is based on FPL's actual and verifiable flotation expenses, however, there simply are no means of verifying whether Dr. Avera's proposal is reasonable or appropriate nor whether it is based on known and measurable FPL costs.

**Q PLEASE DESCRIBE DR. AVERA'S DCF ANALYSIS.**

A Dr. Avera applied the traditional DCF model to two proxy groups that he concludes have reasonably comparable risk to FPL. Based on his utility group, the DCF results yield a return in the range of 9.6% to 10.3%. Dr. Avera's non-utility group includes companies operating in various industries followed by *Value Line*. Based on this non-utility group, his DCF analysis produces a return on equity in the range of 11.5% to 12.3% (Exhibit WEA-13, page 1 of 1).

**Q DO YOU TAKE ISSUE WITH DR. AVERA'S DCF ANALYSES?**

A Yes. I have two major issues concerning his DCF analysis. First, his use of a non-utility proxy group does not reliably estimate a fair return for FPL. Therefore, the DCF results produced by his non-utility proxy group should be rejected.

Second, Dr. Avera's proxy group includes a company that is subject to an acquisition. Third, Dr. Avera's DCF model is based on growth rates that are not sustainable in the long-run as required by the constant growth DCF model.

Q **WHY DO YOU CONSIDER DR. AVERA'S NON-UTILITY GROUP UNREASONABLE?**

A The companies included in Dr. Avera's non-utility proxy group are subject to risks that are different from those affecting FPL's utility operations. As noted by the major credit rating agencies, the utility industry has relatively low risk in comparison with the market. Indeed, the regulatory process itself provides an effective mechanism to mitigate some of the market risks influencing the U.S. economy. Therefore, using Dr. Avera's non-utility proxy group, which is much riskier than the utility industry, will produce an unreliable and inflated return on equity for a low-risk utility like FPL. Therefore, the Commission should disregard the results of Dr. Avera's non-utility group.

Q **CAN YOU PROVIDE AN EXAMPLE OF WHY DR. AVERA'S NON-UTILITY GROUP IS NOT A REASONABLE RISK PROXY GROUP FOR FPL?**

A Yes. One criterion that Dr. Avera uses to select a comparable risk non-utility group in order to estimate FPL's return on equity, is to compare FPL's bond rating to that of the non-regulated group. (Exhibit WEA-3). While this is a reasonable method of estimating and identifying comparable proxy groups within the industry, doing it across industries is not as straightforward and not as reliable. For example, if bond rating alone would adequately help to identify comparable risk companies across industries, then there should not be any observable clear differences in the investment cost for securities that had different bond ratings. However, the industry or circumstances behind the security have a material role in the market's assessment of a fair compensation. For example, U.S. Treasury bonds have a bond rating from Moody's of "AAA." The current yield on a U.S. Treasury bond is around 3.10%. In comparison, corporate bonds with a "AAA" rating currently have costs of approximately 3.90%.[34] A corporate bond is approximately 0.80% more expensive than a Treasury bond, despite the fact that it has the same bond rating.

While "AAA" corporate bonds and U.S. Treasuries have comparable bond ratings, the risk differential is significant largely because of the operating risk differences between the securities. The U.S. government has virtually minimal default risk on its bond issuances, whereas even a "AAA" rated corporate bond has measurable default risk. Similarly, regulated utility operations and the ability to adjust prices to cost of service provide far less default risk than that of non-regulated companies. A regulated company simply has a franchise to a monopolistic service territory, the ability to set prices based on reasonable and prudent costs, and minimal competition. In significant contrast, a non-regulated entity does not have a franchised or monopolistic customer base, must price its services consistent with what the market will permit, and has far more uncertainty of selling products that produce cash flows that support financial obligations.

[34] *Blue Chip Financial Forecasts*, June 1, 2012 at 2.

**Q YOU STATED THAT DR. AVERA INCLUDED A COMPANY SUBJECT TO AN ACQUISITION. PLEASE EXPLAIN.**

A As discussed earlier in my testimony, on page 34 of his direct testimony, Dr. Avera explained that he excluded two companies because they were subject to mergers and acquisitions. However, he did not exclude ITC Holdings Corp., which is in the process of acquiring Entergy's transmission assets as announced on December 4, 2011, and, therefore, fails to meet his proxy group selection criterion.

**Q WHY DO YOU BELIEVE THAT THE GROWTH RATES USED IN DR. AVERA'S DCF STUDY ARE NOT A REASONABLE PROXY FOR LONG-TERM SUSTAINABLE GROWTH?**

A Dr. Avera's DCF results are produced by growth rates in the range of 5.1% to 5.7% as shown on my Exhibit MPG-19. As explained in regards to my own DCF study, utility earnings growth cannot exceed the growth of the economy in the service territory where it sells its goods and services. Therefore, the GDP growth rate is considered a ceiling or a proxy for a maximum sustainable growth rate.

**Q HOW WILL DR. AVERA'S DCF RETURN CHANGE IF A MULTI-STAGE GROWTH MODEL IS APPLIED?**

A I have applied a multi-stage growth DCF model to Dr. Avera's utility proxy group by using the average of his five growth rate estimates for the first stage, which includes the period from year 1 to year 5. The second stage is the transition stage from year 6 to year 10. For the third growth rate stage, which starts in year 11 to perpetuity, I used the projected average 5- to 10-year GDP growth rate of

4.9%. Applying the multi-stage growth DCF version to Dr. Avera's utility group yields average and median DCF returns of 9.6% and 9.5%, respectively, as shown in Exhibit MPG-20.

Q **PLEASE DESCRIBE DR. AVERA'S FORWARD-LOOKING MARKET RISK PREMIUM CAPM ANALYSES.**

A Dr. Avera developed two CAPM analyses based on current and projected Treasury bond yields. Dr. Avera estimates a forward-looking return on the market of 13.5%. From this market return estimate he subtracts his risk-free rate, and the current and projected long-term Treasury bond yields of 3.0% and 4.3%, respectively, to arrive at a market risk premium of 10.5% and 9.2%. He relies on the average utility beta of 0.70 for the companies included in his proxy group to produce an implied cost of equity for his utility group in the range of 10.4% to 10.8%.[35] He then adds a size adjustment to his CAPM return estimate of 0.81% to arrive at his implied cost of equity for the utility proxy group in the range of 11.2% to 11.6%. (Avera Direct, Exhibit WEA-9).

Q **IS DR. AVERA'S FORWARD-LOOKING CAPM ANALYSIS REASONABLE?**

A No. Dr. Avera's CAPM analysis is based on a market risk premium in the range of 9.2% to 10.5%. This market risk premium is significantly higher than the historical market risk premium of 6.6%. Dr. Avera's 13.5% projected market return used to derive the market risk premium of 9.2% to 10.5% is highly inflated and unreliable. This market return estimate is based on a DCF analysis that includes a growth rate projection of 10.9% and a dividend yield of 2.6%.

[35] Exhibit WEA-9.

Dr. Avera's risk premium is dramatically overstated because it is based on a DCF return produced by irrationally high growth outlooks, and is, therefore, not reliable.

Specifically, it is simply irrational to expect that securities market capital appreciation and growth will be at 10.9% for an indefinite period of time, as reflected in Dr. Avera's market study. This is important because the DCF model requires a sustainable long-term growth rate, not simply a growth rate that might be appropriate for the next five years. The growth rate for the overall securities market must reflect the economy in which its companies operate, and the earnings and dividend-paying ability of those companies. Companies produce earnings and dividends by selling goods and services in the marketplace. Hence, companies' earnings growth and sales growth opportunities cannot be substantially in excess of the expected growth in the overall economy. It is simply not a rational expectation to believe that, for an extended period of time, the growth rate of companies will exceed the growth of the overall economy in which they sell their goods and services. As I mentioned above, *Blue Chip Financial Forecasts* projects an average 5- to 10-year nominal growth in the GDP, or overall U.S. economy, of 4.9%.[36] Hence, expecting a growth rate of 10.9%, in essence, assumes that the securities market can grow at a rate more than twice that of the overall U.S. economy. This is simply not a rational expectation.

[36] *Blue Chip Financial Forecasts*, June 1, 2012.

**Q IS DR. AVERA'S PROPOSAL TO INCREASE HIS CAPM RETURN ESTIMATE BY 0.8% TO REFLECT A SIZE ADJUSTMENT APPROPRIATE?**

A No. Dr. Avera's size adjustment is based on estimates made by Morningstar in its *Ibbotson SBBI 2011 Valuation Yearbook.* In that publication, Morningstar estimates various size adjustments based on differentials in utility beta estimates tied to the size of a company. The size adjustment recommended by Dr. Avera reflects companies that have beta estimates in excess of 1.00.[37] These beta estimates are substantially higher than the beta estimates of 0.70 for the proxy utility group used by Dr. Avera as reflective of FPL's investment risk. Therefore, his beta estimates produce a CAPM return estimate that is not risk comparable to FPL and therefore, is not reasonable for setting a fair return for FPL.

**Q HOW WOULD DR. AVERA'S FORWARD-LOOKING CAPM RETURN ESTIMATE CHANGE IF A REASONABLE FORWARD-LOOKING MARKET RISK PREMIUM WERE USED?**

A Applying a market risk premium estimate of 6.6%, a beta of 0.70 and using Dr. Avera's current and projected risk-free rates of 3.0% and 4.3%, respectively, will produce a CAPM return in the range of 7.62% to 8.92%, rounded to 7.6% and 8.9%.

**Q PLEASE DESCRIBE DR. AVERA'S UTILITY RISK PREMIUM ANALYSIS.**

A Dr. Avera's utility bond yield versus authorized return on common equity risk premium is shown in Exhibit WEA-11. As shown on page 3 of this exhibit, Dr. Avera estimated an annual equity risk premium by subtracting Moody's

[37] *2011 SBBI Valuation Yearbook* at 90.

average bond yield from the electric utility regulatory commission authorized return on common equity over the period 1974 through 2011. Based on this analysis, Dr. Avera estimates an average indicated equity risk premium over current utility bond yields of 3.41%.

Dr. Avera then adjusts this average equity risk premium using a regression analysis based on an expectation that there is an ongoing inverse relationship between interest rates and equity risk premiums. Based on this regression analysis, Dr. Avera increases his equity risk premium from 3.41%, up to 5.24% and 4.68% relative to the current and projected average bond yields. He then adds these inflated equity risk premiums to the current and projected "A" rated utility bond yields of 4.33% and 5.72%, respectively, to produce a return on equity of 9.57% and 10.40%, respectively.

**Q ARE DR. AVERA'S UTILITY RISK PREMIUM ANALYSES REASONABLE?**

A No. Dr. Avera develops a forward-looking risk premium model relying on forecasted interest rates and volatile utility yield spreads, which are highly uncertain and prone to inaccurate results. Further, Dr. Avera's proposal to adjust the actual equity risk premium of 3.41% to 5.24% and 4.68% to reflect an inverse relationship between interest rates and utility equity risk premiums is flawed and not reliable. This adjustment is inappropriate and not consistent with academic literature that finds that this relationship should change with risk changes and not simply changes to interest rates.

**Q DO YOU HAVE ANY COMMENTS CONCERNING DR. AVERA'S FORECASTED UTILITY YIELD OF 5.72%?**

A Yes. Dr. Avera develops his forecasted utility yield based on the 6-month historical spreads of "BBB-AA" and "A-AA" rated utility bond yields of 0.90% and 0.28%, respectively, added to his projected "AA" utility bond yield of 5.44%. (Exhibit WEA-6). This approach is unreasonable because Dr. Avera relies exclusively on projected interest rates. The accuracy of his projections is highly problematic. Indeed, while interest rates have been projected to increase over the last several years, those increased interest rate projections have turned out to be wrong.

**Q WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?**

A Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit MPG-21 illustrates this point. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years in the future. In Column 1, I show the actual Treasury yield and, in Column 2, I show the projected yield two years out.

As shown in Columns 1 and 2, over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show what the Treasury yield actually turned out to be two years after the forecast. Under Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in this exhibit, over the last several years, economists consistently have been projecting that interest rates will increase. However, as demonstrated under Column 5, those yield projections have turned out to be overstated in virtually every case. Indeed, actual Treasury yields have decreased or remained flat over the last five years, rather than increase as the economists' projections indicated. As such, current observable interest rates are just as likely to predict future interest rates as are economists' projections.

**Q WHY IS DR. AVERA'S USE OF A SIMPLE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS NOT REASONABLE?**

A Equity risk premiums change with the market's perception of the risk of stock investments versus bond investments. This risk relationship depends on many factors including the level of nominal interest rates. Dr. Avera's approach simply ignores all other relevant factors that help to properly gauge the level of equity risk premiums, except for changes in interest rates. Hence, Dr. Avera's simplistic equity risk premium model is unreliable and flawed.

**Q WHY DO YOU BELIEVE EQUITY RISK PREMIUMS VARY BY CHANGES IN RISK PERCEPTION AND NOT ONLY INTEREST RATE CHANGES?**

A Academic studies have shown that, in the past, the relationship between equity risk premiums and interest rates changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[38]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. Interest rate volatility currently is much lower than it was in the 1980s.[39] As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate variability is not as extreme as it was during the 1980s. Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, not simply changes to interest rates.

Importantly, Dr. Avera's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. His results should be rejected by the Commission.

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[38]"The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

[39]Morningstar SBBI, 2009 Yearbook at 95-96.

**Q CAN DR. AVERA'S RISK PREMIUM ANALYSES BASED ON CURRENT AND PROJECTED YIELDS BE MODIFIED TO PRODUCE MORE REASONABLE RESULTS?**

A Yes. Eliminating the inverse relationship adjustment to the equity risk premium of 3.41% and relying on Dr. Avera's current "A" rated utility yield of 4.33% will result in a return on equity risk premium of 7.74%, rounded to 7.7%. Using Dr. Avera's 2011 equity risk premium of 5.09% as shown on page 3 of his Exhibit WEA-11 and his current "A" rated utility yield of 4.33% will result in a return of 9.42%, rounded to 9.4%. Therefore, Dr. Avera's risk premium will be in the range of 7.7% to 9.4%, with a midpoint of 8.6%.

**Q PLEASE DESCRIBE DR. AVERA'S COMPARABLE EARNINGS ANALYSIS.**

A Dr. Avera's comparable earnings analysis is based on *Value Line*'s projected earned return on book equities for his utility proxy group, adjusted to reflect average year equity returns. Based on a review of projected earnings over the next three to five years, and using this methodology, Dr. Avera estimates a return on equity for FPL of 12.0% (Avera Direct at 70). Based on *Value Line* electric utility industry projections, Dr. Avera estimates the return on equity for FPL to be 10.5%. (Avera Direct at 69).

**Q IS THE COMPARABLE EARNINGS ANALYSIS A REASONABLE METHOD FOR ESTIMATING A FAIR RETURN ON EQUITY FOR FPL?**

A No. A comparable earnings analysis does not measure the return an investor requires in order to make an investment. Rather, it measures the earned return on book equity that companies have experienced in the past or are projected to achieve in the future. The returns investors require in order to assume the risk of an investment are measured from prevailing stock market prices. A comparable earnings analysis measures an accounting return on book equity. Therefore, such a return is not developed from observable market data. A return estimate using a comparable earnings analysis can differ significantly from the return investors currently require. Therefore, Dr. Avera's comparable earnings approach should be rejected.

## Return on Equity Performance Adder

**Q PLEASE DESCRIBE FPL'S PROPOSED 25 BASIS POINTS RETURN ON EQUITY PERFORMANCE ADDER.**

A The performance adder rationale is described in FPL witnesses Dewhurst's and Deaton's testimony. The witnesses state that FPL is proposing a 25 basis point return on equity performance adder that will be applied if FPL's residential electric bill is the lowest of residential bills of other Florida utilities. The 25 basis points adder will continue to be included in the development of FPL's rates as long as FPL's residential rate bill is the lowest in the state over succeeding 12-month averages. (Deaton Direct at 23).

**Q IS THE COMPANY'S PROPOSAL FOR A 25 BASIS POINTS RETURN ON EQUITY PERFORMANCE ADDER REASONABLE?**

A No. As outlined in greater detail above, the Company's financial risk is significantly mitigated through an excessive common equity ratio, and its operating risk is reduced through implementation of several regulatory tracker mechanisms. This risk reduction rewards FPL's shareholders through lower investment risks via lower financial risk and lower operating risk. A return on equity performance adder is neither reasonable nor warranted for FPL. Indeed, my recommended return on equity already awards FPL fair compensation.

**Q WOULD A RETURN ON EQUITY PERFORMANCE ADDER INCENTIVIZE FPL TO KEEP COSTS LOW?**

A No. The Company's proposal will justify a return on equity performance adder based on maintaining competitive "residential" rates alone. This incentive then produces an economic reward for FPL to erroneously shift costs to non-residential customers, in an effort to keep its residential costs low and thus justify its return on equity incentive. Setting rates to encourage a bias in class cost of service and rate designs for non-residential customers is inefficient and should be rejected. Indeed, the Company's incentive to keep residential rates low, even at the expense of inflating non-residential rates, can hurt economic development of its service territory, harm its business customers, and negatively impact its service area economy. For all these reasons, FPL's proposal for a return on equity performance adder should be rejected.

## Qualifications of Michael P. Gorman

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

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **PLEASE STATE YOUR OCCUPATION.**

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

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

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

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

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

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

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

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

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

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

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

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

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

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BY CAPT. MILLER:

Q And Mr. Gorman, did you prepare a summary of your testimony?

A I did.

Q Could you please present that to the Commission at this time?

A Thank you. Mr. Chairman, Commissioners, my testimony addresses an appropriate and fair rate of return, including return on equity, embedded cost of debt, and return on common equity.

I recommend that FPL be awarded a return on common equity of 9.25 percent. That's the midpoint in my estimated range of 9.1 to 9.4 percent. I estimated a fair return on equity using a discounted cash flow analysis -- actually, three versions of the DCF study, a risk premium study, two versions, and a capital asset pricing model.

The results of my study indicate a fair return, again, for FP&L in this case in the range of 9.1 percent to 9.40 percent. I also recommend an adjustment to the company's embedded cost of debt to reflect more current estimates of some debt issues that were planned at the time the utility made its filing. That resulted in an adjustment to the embedded cost of debt proposed by FP&L to 25.08 percent from the company's original proposal of 5.24 percent.

I also reviewed the company's capital structure.

Based on that review, I found that the company's common equity ratio of total investor capital, I thought, was excessive, but I nevertheless did not propose adjustments to that capital based on an unreasonably high common equity balance, simply because the company's capital structural was approved by the Commission in the last rate proceeding.

I did, however, propose adjustments to the company's pro forma -- or pro rata adjustments to its capital structure where it synchronized its amount of capital with its rate base. My adjustment to the company's pro rata adjustments dealt with what I believed to be a more appropriate allocation of accumulated deferred income taxes.

In the company's pro rata adjustment they allocated deferred income taxes on the basis of total capital. I recommend that instead deferred income taxes be allocated on the basis of net plant. Deferred taxes are produced by taxable basis depreciation differences related to net plant and they represent an amount of income taxes remitted to the utility from customers that has not yet been remitted to the taxing authorities.

Consequently, while the utility retains that income tax collection from customers before it is remitted to government taxing authorities, it should be used to reduce its cost of service to the greatest extent possible. I believe allocating deferred taxes on the basis of net plant rather than capital accomplishes that objective.

I also responded to the company's estimated return on equity of 11.25 percent, 11.50 percent with a common equity performance adder. I found that Dr. Avera's recommended return on equity of 11.25 percent is excessive, predominantly represents a return appropriate for non-regulated higher risk companies. Adjustments to his analysis would show that a fair return on equity for FP&L is 9.25 percent or lower.

I took issue with the company's proposal for a 25 basis point flotation -- or performance adder. I felt that that was not appropriate because the company is already being fairly compensated for results of management and that compensation is quite generous, based on its cost of service, because of the -- what I believe to be inflated common equity ratio at a fair return on equity.

It particularly would be unreasonable to give them a performance adder on top of an above-market return on equity, as requested by the company. That summarizes my testimony.

CAPT. MILLER: Mr. Gorman is now available for cross examination.

COMMISSIONER BROWN: Thank you. Mr. Wiseman?

MR. WISEMAN: No questions, Madam Chair.

CHAIRMAN BRISE: Mr. Moyle?

MR. MOYLE: I have just a couple.

CROSS EXAMINATION

BY MR. MOYLE:

Q Where are you based?

A Saint Louis.

Q And part of your testimony is opposing the ROE adder, is that right?

A Yes.

Q And you're aware that there's a trigger mechanism that in order for it to continue FPL has to maintain the lowest residential rates?

A Yes, I understand that.

Q Okay. And do you know that or have information that with respect to currently FPL maintaining or having the lowest residential rates, that that may be in part the result of FP&L having more gas-fired power plants than any other utility in Florida?

A It certainly could be an issue. It could also be a result of legacy cost that current management had no direct influence in creating the low cost structure that produces the low residential rates.

The primary concern I had with the performance adder is it doesn't directly measure exceptional management performance based on current management and rewards that performance in a way that -- other than intentionally increasing rates to provide a performance adder.

Q So to the extent that the adder is designed to measure management's judgment in running the company, to the extent that there was action taken by this Commission that denied their ability to build coal plants and resulted in them building more natural gas plants, do you think that that should be credited to management's, you know, business judgment, or is that more akin to serendipity, as another witness termed it yesterday?

A That's precisely the concern I have with the company's performance adder. It doesn't specifically identify any exceptional performance by current management that should be rewarded. Rather, it's simply an end result test that could have been produced either by regulatory oversight of the utility, it could have been produced by previous management of this utility, and those could be embedded in their legacy costs, which impacts the cost of service. It could be a whole host of other market factors which the utility was in a position to take advantage of that were not the result of exceptional management performance.

COMMISSIONER BROWN: And Mr. Moyle, excuse me for interrupting, but I just want to point out, again, Mr. Gorman, as I said to the last witness, if you could please limit your answer -- preface it by a yes or no, if possible, and then provide a succinct explanation to that, that would be greatly appreciated.

THE WITNESS: Thank you. I apologize.

BY MR. MOYLE:

Q I'm going to change gears a little bit and ask you just a couple of questions about another area of your testimony. You talk about the capital structure. Do you know -- can you tell us if FP&L's capital structure as it currently exists is either the highest in the country with respect to investor-owned utilities, or among the highest with respect to capital structure and the amount of equity of investor-owned utilities?

MR. GUYTON: I object to the question as being friendly cross. We've indulged some, but it's clearly friendly cross, which has been prescribed by the prehearing order and the order on --

COMMISSIONER BROWN: Yes, it has. Mr. Moyle?

MR. MOYLE: I'll withdraw the question.

COMMISSIONER BROWN: Are you finished?

MR. MOYLE: Yes, ma'am.

COMMISSIONER BROWN: Thank you. Florida Power & Light?

MR. GUYTON: Florida Power & Light has no questions for Mr. Gorman.

COMMISSIONER BROWN: Okay. Office of Public Counsel?

MR. McGLOTHLIN: No questions.

COMMISSIONER BROWN: No questions? Retail Federation?

MR. LaVIA: No questions.

COMMISSIONER BROWN: Mr. Saporito?

MR. SAPORITO: Yes, Madam Chair, I have a couple questions.

CROSS EXAMINATION

BY MR. SAPORITO:

Q Hi, my name is Tom Saporito. I'm here pro se. You testified with respect to the ROE performance adder with these other counsel to my right. And my question is, if the -- assuming that the performance adder is based on management's performance, solely, assuming that hypothetical, if management at FP&L is already getting a performance award through their compensation, in your opinion, would an ROE performance adder of .25 percent be a duplicate?

MR. GUYTON: Objection. Not only is this friendly cross, but it's now beyond the scope of this witness's testimony.

COMMISSIONER BROWN: I'll sustain the objection.

BY MR. SAPORITO:

Q And the other question I had was you gave an opinion of what you believe the Commission should authorize in ROE. And just refresh my memory. Was that 9.4 percent?

A A range of 9.1 to 9.4, with a midpoint point estimate of 9.25 percent.

Q Can you provide this Commission with an opinion that your range that you assigned to that midpoint, if FPL's performance was superior performance, to use that term, would they not be compensated for that superior performance by the upper end of your recommended range?

MR. GUYTON: Objection, friendly cross.

COMMISSIONER BROWN: Can you rephrase the question?

BY MR. SAPORITO:

Q Does your recommended range from the midpoint you've recommended to this Commission provide an opportunity for FPL to be rewarded based on their performance?

A Well, I recommend that rates be set to provide fair compensation to FPL, and exceptional management performance will allow it to actually earn a return that is equal to or higher than the authorized return, and that will provide compensation to FPL's investors, which may also be considered incentive performance compensation for executives and employees.

MR. SAPORITO: Thank you, Madam Chairman. That's all I have.

COMMISSIONER BROWN: Thank you. Mr. Hendricks?

CROSS EXAMINATION

BY MR. HENDRICKS:

Q Good afternoon, Mr. Gorman.
A Good afternoon.
Q On page eight, I believe it is, of your testimony, you talk about declining capital market costs, and you give a couple of examples: 1.5 to 1.2 percent decline over a period of time.
A Right, that's --
Q Could you -- could you tell me, are you implying with that that the cost of equity should follow those costs down?
A Yeah.
MR. GUYTON: Objection, friendly cross.
COMMISSIONER BROWN: Mr. Hendricks?
MR. HENDRICKS: Is it? You tell me.
COMMISSIONER BROWN: My opinion is that it is, but could you rephrase the question? I'll give you some latitude here.
BY MR. HENDRICKS:
Q What conclusion would you draw from that fact that you've pointed out?
A Well, measuring the company's current cost of equity is a very difficult undertaking. It's subject to judgment and the opinion of the rate of return analyst. But there are some elements of current capital market costs that can be observed and verified in the marketplace.

Common equity investments do compete with debt investments for investor capital. Common equity is more risky than debt, so the market required return is known to be higher than that of debt capital. But there is a relationship, because there is competition between debt security and common equity security for market capital investments.

So observing that utility cost of debt has declined is clear evidence that the cost of common equity has declined, unless there's extraordinary circumstances which would cause the premium for an equity investment to increase relative to that debt investment.

So it is observable market evidence that capital market costs have declined for utility companies, which is a very strong indication that the cost of common equity for a utility company has also declined.

Q I believe it's on page 24. Let me see if I can find my reference here. I believe that's correct. You say something I found a little confusing. You said that you thought the -- you had some criticism of the capital structure but you did not recommend any change because it was approved by the Commission? Is that correct?

MR. GUYTON: Objection, friendly cross. It's just an elaboration of direct.

MR. HENDRICKS: I disagree. It's not an

elaboration, it's trying to get -- it's a -- he said something that's counterintuitive, and I'm trying to understand why he said it.

COMMISSIONER BROWN: Mr. Hendricks, are you asking for the witness to clarify?

MR. HENDRICKS: Yes.

COMMISSIONER BROWN: Okay, I'll allow it.

THE WITNESS: I did review the company's capital structure, invested capital, and I believe that its common equity ratio of total capital is very high for a relatively low risk electric utility company like FP&L. I do think it's an excessive amount of common equity.

I did not make an adjustment to that capital structure because I believe the Commission had already approved the use of a high common equity capital structure in setting rates for FP&L.

BY MR. HENDRICKS:

Q Did you mean to say that if the Commission at some time in the past approved a particular equity ratio, that they therefore have to approve a similar one in the future?

A That's not my testimony. That's simply the reason why I did not propose an adjustment here. I think it is appropriate, as Mr. Kollen stated before, to ask the Commission to reconsider a prior determination for new facts in this record.

However, in this case, I didn't offer any new facts, and I did not propose an adjustment to the capital structure.

MR. HENDRICKS: Thank you. No more questions.

COMMISSIONER BROWN: Okay, thank you. Staff?

MR. YOUNG: Madam Commissioner, in lieu of Staff's questions, Staff would ask that deposition -- I mean, the deposition of the witness, including the errata sheet, be entered into the record, and that is hearing Exhibit Number 119. The parties have -- the parties that I've spoken to, if they haven't changed their minds, have agreed to this form of -- this form of evidence being entered into the record.

COMMISSIONER BROWN: Okay. Mr. Young, would it be your preference to do that now or after redirect?

MR. YOUNG: After redirect.

COMMISSIONER BROWN: Okay. Commissioners? Nothing. Redirect?

CAPT. MILLER: Just briefly, Ms. Chairman.

REDIRECT EXAMINATION

BY CAPT. MILLER:

Q Mr. Gorman, do you recall Mr. Moyle asking you questions about the ROE performance adder?

A Yes.

Q And he specifically asked you questions about management excellence, and whether or not that contributes to the adder?

A Yes.

Q And at one point in his cross examination he referred to natural gas generation, and specifically he referred to Commission direction for FP&L to actually generate natural gas.

A Yes.

Q Do you -- are you aware specifically of what Commission direction that is?

A I am generally familiar with a direction from the Commission to FPL to use a gas-fired generation rather than a clean coal technology unit. And one, as I understand it -- the reason for that direction is because the natural gas-fired generation would be lower cost than the clean coal technology. So that would contribute to low residential rates and the result of those low rates then could be attributed to Commission directions to FP&L, rather than FPL's management decision-making and planning.

CAPT. MILLER: At this point I'd like to have an exhibit marked.

COMMISSIONER BROWN: Okay, that would be 585. Staff?

(Exhibit 585 marked for identification.)

COMMISSIONER BROWN: Any objections?

MR. GUYTON: I believe we may have one. I need to see if He can get it authenticated through this witness.

COMMISSIONER BROWN: Okay.

BY CAPT. MILLER:

Q Mr. Gorman, I'll give you a minute to read it over.

COMMISSIONER BROWN: Captain Miller, I'm hoping that your question is going to pertain to something that was elicited during direct -- during cross examination.

CAPT. MILLER: Yes.

COMMISSIONER BROWN: Okay.

THE WITNESS: I have reviewed this.

BY CAPT. MILLER:

Q Mr. Gorman, you said you were generally aware of the Commission directing FP&L to generate natural gas?

A Particularly one situation where they described in this news release --

MR. GUYTON: I'm sorry, I'm going to object to the witness referring to this piece of paper that's being characterized as a news release until we know that it's authentic.

COMMISSIONER BROWN: Captain Miller?

CAPT. MILLER: Yes, Commissioner. First I would say that the document is self-authenticating based that it's pulled directly off FPL's website.

Secondly, I think throughout this hearing the barriers for authenticity have been considerably low. And finally, regarding hearsay, I'd say it's a statement against interest.

COMMISSIONER BROWN: Well, this Commission does take -- can consider hearsay and give it the weight that it's due, but I will turn to our Commission Counsel for guidance. Do you have a copy of this?

MS. HELTON: Yes, ma'am. It does say on the bottom that it's copyrighted for Florida Power & Light Company. I'm not sure that the witness, though, has said that he has any direct knowledge of this information that's related here, so I'm having a hard time determining whether it's relevant to the cross examination at issue. I think he had to actually refer to the newspaper article to be able to answer the question from counsel for FEA.

So it seems to me, unless the counsel from FEA can kind of bring it, the relevance, in, that it's not relevant to the cross examination.

COMMISSIONER BROWN: Mr. Gorman? I'm sorry. Captain Miller?

CAPT. MILLER: Mr. Commissioner, yes, Mr. Gorman said that he was generally aware of the Commission direction for FP&L to produce natural gas. I just wanted to use this document to refresh whatever recollection he has of that, and, you know, have him answer questions on it, very specific questions, you know, basically showing, this is a specific example of that happening.

COMMISSIONER BROWN: I'm having a hard time seeing the relevance related, though, to the cross examination. I have no problem with it coming right off of the Florida Power & Light website, if he can testify to that, but you have to direct your question specifically to the cross examination that occurred.

CAPT. MILLER: Okay. Honestly, the only question I had was, you know, whether or not this made him more familiar, you know, sparked his memory with his general knowledge of it, so that's all I have.

COMMISSIONER BROWN: Okay. So are you offering this exhibit into evidence, then?

CAPT. MILLER: At this point I am.

COMMISSIONER BROWN: Ms. Helton?

MS. HELTON: This certainly wouldn't be the first time the Commission has admitted a news release or newspaper article into evidence. It is copyrighted by Florida Power & Light Company, according to the bottom of the page.

Counsel suggested that it's an admission against interest. It could -- I think maybe, you know, if you admitted it and gave it the weight that it was due, I think we could move on.

COMMISSIONER BROWN: And I'm comfortable doing that, but I don't think we are admitting anything yet, unless you're finished with redirect.

CAPT. MILLER: I am finished.

COMMISSIONER BROWN: Okay, let's get to exhibits now. Captain Miller?

CAPT. MILLER: FEA would move for exhibits identified as 349 to 370 into the record.

COMMISSIONER BROWN: Okay. Are there any objections? We will move in -- seeing no objections, we are going to move Exhibits 349 through 370 into the record. Staff?

(Exhibits 349 through 370 admitted in evidence.)

MR. YOUNG: Staff would move what is now amended 119, the deposition of witness Gorman, and the errata sheet.

COMMISSIONER BROWN: Okay. Any objections? We're going to move Staff's Exhibit 119 with the errata sheet and the deposition into the record. And back to you.

(Exhibit 199 admitted in evidence.)

CAPT. MILLER: I would also move 585.

COMMISSIONER BROWN: Objections?

MR. GUYTON: Yes, Commissioner, we don't think the document has been authenticated, it is clearly hearsay, something that should not be relied upon. It was not relied upon by this witness, nor is there testimony to the effect that it had been relied upon by this witness. And indeed, I objected, and he was never asked about this document.

COMMISSIONER BROWN: And that is the reason why I will exclude it, the latter part, because it was not relied upon and the witness could not testify and did not answer any questions to it. So I'm not going to allow Exhibit 585. Captain Miller, would you like to excuse this witness?

CAPT. MILLER: I would. Thank you.

COMMISSIONER BROWN: All right, Mr. Gorman, you're excused. We are going to take a 10-minute break at this point, and I have 2:45, so the court reporter can take some time and we can get adjusted, so we can reconvene, I'd say, at five till.

MR. SAPORITO: Madam Chairman, can I just quickly -- are we going to reuse 585 now?

COMMISSIONER BROWN: No, we are not.

MR. SAPORITO: That's number is used?

COMMISSIONER BROWN: No, it's --

MR. SAPORITO: It's open?

COMMISSIONER BROWN: 585 is open.

MR. SAPORITO: Thank you.

COMMISSIONER BROWN: All right, we will recess until 5:55.

(Brief recess)

CHAIRMAN BRISE: All right, Staff, where are we at this time?

MR. YOUNG: Madam Chairman, the next witness up is FEA witness Stephens, which has been stipulated. I think FEA wants to make a request.

CAPT. MILLER: Yes, I would now like to move the prefiled testimony of FEA witness Robert Stephens into evidence.

COMMISSIONER BROWN: Without any objections we will move Mr. Stephens prefiled testimony into the record, into evidence.

**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| **In Re: Petition for Increase in Rates by Florida Power & Light Company** ) | **Docket No. 120015-EI** |

**Direct Testimony of Robert R. Stephens**

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

A Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **WHAT IS YOUR OCCUPATION?**

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

Q **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

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

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

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

A I will address certain cost of service and rate design issues.

**Q PLEASE SUMMARIZE YOUR DIRECT TESTIMONY IN THIS CASE.**

A My direct testimony can be summarized as follows:

1. I provide an overview of the basic steps needed for establishment of fair and reasonable rates, including the development and use of embedded cost of service studies.
2. I have found three shortcomings in FPL's embedded cost of service study, all related to distribution costs.
   a. It does not appear that FPL has properly separated primary voltage and secondary voltage distribution costs.
   b. FPL should include single-phase primary voltage facilities as functioning only to serve secondary voltage customers and, thus, allocating the cost only to secondary voltage customers.
   c. FPL's cost study ignores the customer-related component of the distribution system associated with the minimum distribution system.
3. I recommend that each of the shortcomings identified above be corrected in this case (in the case of the first item) and in the next rate case for the second and third items.
4. With respect to rate design, I recommend that the rate moderation approach used in revenue allocation be modified from FPL's proposal. Specifically, a 1.5x (times) system average increase criterion should be applied to the base rate charges, rather than total revenues including adjustment clauses.

## COST OF SERVICE

Q **HAVE YOU REVIEWED THE DIRECT TESTIMONY OF FLORIDA POWER & LIGHT COMPANY ("FPL" OR "COMPANY") AS IT RELATES TO CLASS COST OF SERVICE?**

A Yes, I have. This subject is addressed in the testimony and exhibits of Company witness Joseph A. Ender. My focus is on the retail cost of service study and its results, which Mr. Ender addresses beginning at page 20 of his testimony.

Q **CAN YOU PLEASE PROVIDE AN OVERVIEW OF THE PURPOSE OF UTILITY COST OF SERVICE STUDIES AND HOW THEY FIT INTO THE RATEMAKING PROCESS?**

A Yes.

### Overview

Q **PLEASE EXPLAIN THE BASIC STEPS FOR ESTABLISHMENT OF FAIR AND REASONABLE RATES?**

A The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how any increase or decrease in revenues is to be distributed among the various customer classes, i.e., the class revenue allocation. A determination of how many dollars of revenue should be produced by each class is essential of obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues from each class of service and to send efficient price signals to customers.

The standard tool for determining whether a class requires a rate increase or decrease is an embedded class cost of service ("ECOS") study, which shows the rate of return for each class of service. Ideally, rate levels should be modified so that each customer class provides approximately the same rate of return. Finally, in designing individual tariffs, the goal is to base the rate design on the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing that service to the customers on the tariff.

Q **HOW ARE LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS AFFECTED BY THE PRICE OF ENERGY?**

A For many large commercial and industrial customers, energy is a primary component of their costs. For some, it may be the most critical component. As such, rate stability and overall cost of electricity prices are vital to the economic health of large commercial and industrial customers in Florida, and to the economic health of Florida itself. Furthermore, any cost of service study or rate design that misallocates costs to large customers will also result in unjust and unreasonable rates.

Q **WHAT IS THE BASIC PURPOSE OF AN ECOS STUDY?**

A The basic purpose of a class cost of service study is an empirical determination of the cost of serving classes of customers. After determining the overall cost of service or revenue requirement, an ECOS study is used to ascertain the cost of service among customer classes; i.e., a cost of service study shows how each customer class contributes to the total system cost. For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues just sufficient to cover the costs incurred in serving it (including a reasonable authorized return on investment). If a class produces a below-average rate of return, it may be concluded that the revenues are insufficient to cover all relevant costs. On the other hand, if a class produces a rate of return above the average, it is paying revenues sufficient to cover the cost attributable to it and, in addition, is paying part of the cost attributable to other classes who produce a below-average rate of return. The class cost of service study is important because it shows the class revenue requirement, as well as the rate of return under current and any proposed rates.

Q **PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A COST OF SERVICE STUDY.**

A In all cost of service studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the functionalization of costs, as well as the classification of the nature of these costs as to whether they vary with the quantity of energy consumed, the demand placed upon the system or the number of customers being served. Stated another way, functionalization is the classification and arrangement of costs according to major functions, such as production, transmission, and distribution.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in output and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the investment in utility facilities, and those costs necessary to keep the facilities "on-line." Variable costs, on the other hand, are basically those costs which tend to vary with output and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of energy consumed or the peak demands placed upon the system. An understanding of these concepts is essential to cost of service studies, as well as appropriate rate design.

## FPL's ECOS Study

**Q HAVE YOU REVIEWED THE ECOS STUDY PROVIDED BY FPL?**

A Yes.

**Q PLEASE DESCRIBE WHAT YOU DETERMINED FROM YOUR REVIEW.**

A The ECOS study presented in FPL witness Joseph Ender's direct testimony uses the 12 MCP & 1/13$^{th}$ kilowatthour ("kWh") allocation for generation and transmission costs, with the exception that the cost of transmission "pulloffs," which are essentially the "service drops" for transmission voltage customers, are allocated only to transmission customers. Distribution costs that FPL deems to be demand-related are allocated on non-coincident peak ("NCP") demand allocation factors for primary and secondary distribution costs.

**Q DOES FPL's ECOS STUDY ADEQUATELY MEASURE CLASS COSTS?**

A FPL witness Mr. Ender states:

> "FPL's cost of service study results for the projected 2013 Test Year are accurately determined and fairly present each rate class's cost responsibility, Rate of Return ("ROR"), and parity position relative to FPL's projected retail jurisdictional ROR.

> These results reflect the forecast of base revenues for each rate class, and an equitable allocation of rate base, other operating revenues, and expenses. The methodologies used to allocate rate base, other operating revenues, and expenses were appropriately applied and are consistent with those previously approved by this Commission." (Direct Testimony of Joseph A. Ender, page 5, lines 5-12).

Unfortunately, FPL's cost of service study fails to measure up to Mr. Ender's claims regarding it. Specifically, FPL's ECOS study fails in three significant ways: First, it fails to clearly segregate the cost of distribution equipment into primary voltage and secondary voltage components, and therefore appears to inappropriately allocate the costs of secondary voltage equipment to primary voltage customers. Second, it fails to recognize that primary voltage lines that are operated in single-phase and dual-phase configurations are rarely constructed to serve primary voltage loads and function primarily to serve secondary customers, and therefore should be allocated to primary voltage customers using only the levels of demand, if any, that are served by those facilities. Finally, FPL's ECOS study fails to recognize that a significant portion of distribution costs - other than the cost of services and meters, are incurred on a per customer basis (i.e., they are incurred whenever service is provided to additional customers, and are incurred regardless of customer demand.)

## Separation of Primary and Secondary Distribution Costs

**Q DOES MR. ENDER CLAIM TO SEGREGATE PRIMARY AND SECONDARY COSTS IN HIS ECOS STUDY?**

A Yes, he does. However, it is unclear from my review whether the FPL ECOS study actually does what Mr. Ender claims. In his direct testimony, Mr. Ender states:

> "... Substations and primary voltage lines are allocated on the basis of the GNCP of customers served from the distribution system. Secondary voltage lines are allocated on the basis of the GNCP of customers served at secondary voltage levels. Transformers are allocated on the basis of the NCP of customers served at secondary voltage levels." (Direct Testimony of Joseph A. Ender, page 22, lines 19-23).

However, upon review of Mr. Ender's workpapers and the minimum filing requirement ("MFR") schedules, I see no evidence that primary and secondary costs are actually segregated. Rather, it appears that FPL only adjusts the loads it used to develop the demand allocation factors so that they reflect the portions of load received at primary and secondary voltages.

**Q PLEASE EXPLAIN WHAT YOU MEAN?**

A Mr. Ender identifies MFR schedules E-1 through E-6 as those pertaining to the cost of service. Specifically, Mr. Ender sponsors Exhibit JAE-1 which is titled "MFRs and Schedules Sponsored or Co-Sponsored by Joseph A. Ender." Upon review of Exhibit JAE-1 and the MFR schedules referenced by it, I have been unable to find any exhibit that shows how distribution facility costs are segregated into primary facilities and secondary facilities. I have also been unable to identify any schedule that shows the costs associated with primary and secondary facilities being separately allocated.

Q **IS IT YOUR BELIEF THAT THESE COSTS ARE NOT BEING ALLOCATED AS MR. ENDER HAS CLAIMED?**

A No; I am only saying that if these costs are separated into primary and secondary voltage components, this step is not shown in any of the exhibits or schedules I have reviewed. Neither the MFR schedules sponsored by Mr. Ender, nor the exhibits attached to his testimony show the segregation and allocation of secondary facilities costs separate and distinct from the allocation of primary voltage facility costs.

Q **WHY IS THIS AN IMPORTANT ISSUE?**

A The separation of distribution costs into primary and secondary portions is important because it ensures that customers served at primary voltages, and which do not receive any benefit whatsoever from the secondary distribution system, will not be allocated costs associated with that secondary distribution system. In contrast, customers who take service at secondary voltage utilize both the secondary system and, in part, the "upstream" primary voltage system.

Q **WHAT DO YOU RECOMMEND ON THIS ISSUE?**

A I recommend that in his rebuttal testimony, Mr. Ender make more clear and provide explicit evidence that FPL has, in fact, segregated primary and secondary voltage facilities. Alternatively, if FPL has not done so, as suggested by my review of the ECOS study, then it should modify its ECOS study in order to properly take these considerations into account.

## Recognizing Single-Phase Primary Voltage Facilities as Functioning Only to Serve Secondary Voltage Customers

**Q DO YOU HAVE CONCERNS ABOUT ANY OTHER ASPECTS OF THE COMPANY'S ECOS STUDY?**

A Yes. I believe the allocation of certain distribution system plant costs should be more refined.

**Q WHY IS A REFINEMENT TO THE DISTRIBUTION PLANT ALLOCATION NEEDED?**

A The Company has made no attempt to separate the cost of its single-phase primary distribution system from its three-phase primary distribution system. As a result, the Company's ECOS study allocates costs related to single-phase primary distribution circuits to both primary voltage customers and secondary voltage customers[1] and, therefore, is unreasonable. This allocation is not reasonable because single-phase distribution equipment generally is not used in any significant way to serve primary customers. Therefore, the Company's ECOS study does not properly allocate these distribution costs to the customers for which they are incurred. The ECOS study should be refined to ensure that

[1]Primary voltage customers are metered at 600 volts or higher and will be referred to as "primary customers." Similarly, secondary voltage customers are metered at voltages below 600 volts, and will be referred to as "secondary customers."

customer classes pay for primary voltage facilities only to the extent that those facilities are used to serve them.

**Q PLEASE DEFINE THE TERM "PHASE," AS IT IS USED TO DESCRIBE SINGLE- DUAL- OR THREE-PHASE, PRIMARY DISTRIBUTION CIRCUITS?**

A When power is generated, it leaves the generating plant in three separate phases, and is transmitted via separate conductors for each phase. Single-phase primary distribution circuits are composed of a single conductor that is energized to a primary voltage level, and a ground conductor. Dual-phase primary distribution circuits consist of two energized conductors and a ground conductor and three-phase primary distribution circuits consist of three energized conductors and a ground conductor. All household appliances, for example, operate on single-phase service, while some industrial applications, such as large motors, operate on three-phase service.

The costs of single- and three-phase distribution facilities are recorded in FERC Accounts 364 – Poles and Towers, 365 – Overhead Conductors and Devices, 366 – Conduit and 367 – Underground Cables and Devices.

**Q WITH RESPECT TO ELECTRICAL DISTRIBUTION SYSTEMS, HOW DO THE NUMBER OF PHASES COMPARE TO THE VOLTAGE LEVEL?**

A Theoretically, the number of phases and the voltage level are separate and independent parameters of a distribution system. Therefore, a single-phase circuit *could* operate on one of any number of primary or secondary voltages. Likewise, a primary voltage customer could receive single-phase, dual-phase or three-phase service. In practice, however, certain phase/voltage combinations (such as when a single-phase primary circuit is used to serve the heavy load of a primary voltage customer), can lead to instabilities on the electric system and are only used when no other alternative is available. For this reason, costs associated with single-phase primary distribution circuits are predominantly incurred to serve secondary voltage customers. They are seldom used to serve primary voltage customers.

**Q HOW SHOULD DISTRIBUTION SYSTEM COSTS BE ALLOCATED IN THE ECOS STUDY?**

A Other than those that are directly assigned, distribution system costs should be sorted into three separate sub-functions: (1) three-phase primary costs; (2) single- and dual-phase primary costs; and (3) secondary costs. Three-phase primary costs should be allocated to all customer classes on the basis of peak demand, since these costs are incurred to serve both primary and secondary voltage customers. However, single- and dual-phase primary circuits are not often, if at all, used to serve primary customers. Therefore, single- and dual-phase primary circuit costs should be allocated to the rate classes based only on the load served via such circuits. Secondary costs, of course, should be allocated only to secondary customers.

**Q HAS THE COMPANY SORTED THE DISTRIBUTION CIRCUIT COSTS INTO THE SUB-FUNCTIONS AS YOU HAVE DESCRIBED?**

A No. As I stated earlier, the Company claims to separate distribution costs into primary and secondary sub-functions, but has not provided any exhibits or schedules showing this separation. Rather, FPL's ECOS study appears to combine distribution costs by FERC Account, and does not differentiate facility costs by voltage level or phase configurations. As such, FPL's ECOS study method is imprecise. By allocating distribution costs as it does, the Company significantly overstates the cost of serving primary customers, nearly all of which tend to utilize three-phase service.

Q **HAVE YOU REFINED THE COMPANY'S ECOS STUDY TO CORRECT ITS MIS-ALLOCATION OF COSTS ASSOCIATED WITH SINGLE- AND DUAL-PHASE PRIMARY DISTRIBUTION FACILITIES?**

A No, I have not. It would be relatively difficult and time consuming for a non-utility party to have adequate access to records to perform the necessary separations of cost. I have not attempted to do so in the context of this case.

Q **IS IT REASONABLE TO EXPECT FPL TO BE ABLE TO SEPARATE COSTS BY SUB-FUNCTIONS AS YOU HAVE DESCRIBED?**

A Yes, it is. To begin, single-phase circuits operate at different voltages than three-phase circuits. The common reference to 12 kV, 34.5 kV or 69 kV circuits actually refers to the voltage difference between one energized phase wire and another, that is, the phase-to-phase voltage. Single-phase circuits, however, are typically "split off" from three-phase circuits and are designated by their phase-to-ground voltage, which is generally about 58% of phase-to-phase voltage of the three-phase circuit they originate from. Thus, a single three-phase circuit operating at 12 kV (phase-to-phase) can be split into three single-phase circuits that operate at 7.2 kV (phase-to-ground) each. To ensure the safe and reliable operation of its system, utilities like FPL generally will have operational systems in place such as automated mapping/facility management (AM/FM), supervisory control and data acquisition (SCADA) and geographic information systems (GIS) that should make the identification of single-, dual- and three-phase circuits a relatively simple task.

**Q WHAT IS YOUR RECOMMENDATION IN THIS REGARD?**

A The Company should be required to alter its ECOS study so that the costs of primary distribution facilities are allocated to the customer classes in a manner that reflects cost-causation. Specifically, three-phase primary system costs should be allocated to primary and secondary customers, but the costs associated with single- and dual-phase, primary distribution should be allocated only to rate classes in proportion to the amount of class load served by those facilities. If this cannot reasonably be accomplished in this case, it should happen at the next opportunity, e.g., the next rate case.

## Finding the Customer-Related Component of the Distribution System

**Q DOES FPL USE COST OF SERVICE METHODS TO IDENTIFY A PORTION OF PRIMARY AND SECONDARY DISTRIBUTION COSTS AS CUSTOMER-RELATED?**

A No. In its allocation of distribution system costs, FPL identifies only the costs of services[2] and meters as customer-related costs. FPL fails to recognize that there is a customer-related component in the costs recorded in FERC Account 634 – Poles and Towers, Account 365 – Overhead Conductors and Devices, Account 366 – Conduit, Account 367 – Underground Cables and Devices and Account

[2]Transmission and Primary voltage "pull-offs," which are similar to services, are allocated to transmission and primary customers, respectively, on the basis of customer numbers.

368 – Line Transformers, because there is a minimum cost the Company must incur simply to provide service to its customers. This minimum distribution system ("MDS") cost must be incurred whenever a new customer is added to the system, and regardless of the customer's level of demand.

**Q IS RECOGNITION OF MINIMUM COSTS A NEW COST OF SERVICE CONCEPT?**

A No. Such costs are often recognized in the concept known as the MDS, which represents a collection of costs that must be incurred to extend distribution service to the customers. The MDS has been accepted as valid by numerous state public utility commissions for decades. It has also been presented in the NARUC Manual.[3]

The central idea behind the MDS concept is that there is a cost incurred by a utility when it extends its primary and secondary distribution system, or replaces a component on those systems, that is caused by the utility's obligation to connect customers to its distribution system. This extension of the distribution system is how the utility was built up over decades. By definition, the MDS represents a portion of the cost of every distribution component necessary to provide service, (i.e., meters, services, secondary and primary wires, poles, substations, etc.). The cost included in the MDS, however, is only that portion of the total distribution cost that the utility must incur to provide service to customers; it does not include costs specifically incurred to meet the peak demand requirements of the customers.

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[3]National Association of Regulatory Utility Commissioners "Electric Utility Cost Allocation Manual" ("NARUC Manual"), 1992. See Chapter 6, Section II, pages 90-96 of the NARUC Manual.

It is noteworthy that, historically, some opponents to the MDS have incorrectly described it as a method that is based on a set of distribution facilities designed to serve zero or minimum load requirements of customers. This is a faulty description and leads to faulty conclusions. Therefore, it is worth repeating that the MDS method attempts to account for only that portion of the total distribution cost that the utility must incur to provide service to customers; it does not try to measure a specific capacity (i.e., zero or minimum load) of the system.

**Q WHAT ARE THE COST-CAUSATIVE FACTORS OF UTILITY DISTRIBUTION SYSTEM INVESTMENT?**

A Although it is widely agreed that distribution systems are installed in anticipation of a projected level of peak load, this load is not the only cost-causative factor affecting the cost of the distribution system. Safety and reliability standards, as mandated in the Florida Administrative Code ("F.A.C."), also have a cost-causative impact on the installation of FPL's distribution system. Furthermore, these cost-causative factors have a clearly identifiable "minimum" requirement that is directly related to the number of customers on the system. For example, F.A.C. Rule 25-6.034 – Standard of Construction, states:

"Each utility shall, at a minimum, comply with the National Electrical Safety Code [ANSI C-2] [NESC], incorporated by reference in Rule 25-6.0345, F.A.C. [4]" (F.A.C. Rule 25-6.034, subpart (2), emphasis added).

This rule, in and of itself, clearly shows that the requirements of the National Electrical Safety Code ("NESC") serve as the basis of the smallest distribution system that every Florida utility must construct.

However, other F.A.C. rules mandate that certain facilities be constructed to NESC standards that are significantly higher than the minimum NESC requirements. For example, F.A.C. Rule 25-6.0342 – Electric Infrastructure Storm Hardening states:

"...This rule is intended to ensure the provision of safe, adequate, and reliable electric transmission and distribution service for operational as well as emergency purposes; require the cost-effective strengthening of critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions. This rule applies to all investor-owned electric utilities." (F.A.C. Rule 25-6.0342, subpart (1), emphasis added).

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[4]F.A.C Rule 25-6.0345 – Safety Standards for Construction of New Transmission and Distribution Facilities states:

"(1) The Commission adopts and incorporates by reference the 2002 edition of the National Electrical Safety Code (ANSI C-2) [NESC], as the applicable safety standards for transmission and distribution facilities subject to the Commission's safety jurisdiction. For electrical facilities constructed on or after February 1, 2007, the 2007 NESC shall apply..."

This rule mandates that the storm hardening plans adopt the extreme wind loading standards specified in the 2007 version of the NESC, for new construction, major planned expansions, rebuilds, or relocations of existing facilities, and critical infrastructure facilities. Such F.A.C. rules cause Florida's electric utilities to incur costs in a manner that is, in no way whatsoever, related to the peak load of the customers, but is directly related to the existence of customers on the system and the facilities required to provide any level of service at all.

**Q WHAT EVIDENCE EXISTS THAT SUGGESTS THESE DISTRIBUTION COSTS ARE DIRECTLY RELATED TO THE NUMBER OF CUSTOMERS ON THE SYSTEM?**

A As I have already stated, F.A.C. Rule 25-6.0342 requires that planned expansions, upgrades, or relocations of facilities be constructed to "extreme weather conditions." F.A.C. Rule 25-6.064 describes how financial contributions from customers (i.e., Contributions-in-Aid-of-Construction or "CIAC"), that are collected to pay for a portion of the costs of these new or upgraded facilities, should be treated. This rule states:

> "All CIAC calculations under this rule shall be based on estimated work order job costs. In addition, each utility shall use its best judgment in estimating the total amount of annual revenues which the new or upgraded facilities are expected to produce.
>
> (a) ...
>
> (b) In cases where more customers than the initial applicant are expected to be served by the new or upgraded

> facilities, **the utility shall prorate the total CIAC over the number of end-use customers** expected to be served by the new or upgraded facilities within a period not to exceed 3 years, commencing with the in-service date of the new or upgraded facilities." (F.A.C. Rule 25-6.064, subpart (6), emphasis added).

The language in this F.A.C. rule provides support for the idea that the costs associated with providing service to customers, which is what the CIAC is intended to offset, is directly proportional to the number of customers being served. It is a small step to recognize that the costs that are not offset by CIAC payments, i.e., costs that are recorded in FERC Accounts 364 through 368, are also incurred in direct proportion to the number of customers.

## Commission's Acceptance of MDS for Choctawhatchee Electric Cooperative, Inc. ("CHELCO")

**Q HAS THE COMMISSION RULED ON THE USE OF MDS IN ALLOCATING DISTRIBUTION COSTS IN THE PAST?**

A Yes, it has. Unfortunately, the Commission has generally failed to recognize this very real cost driver in allocating costs in several instances. However, this does not mean that the Commission has never recognized MDS in cost studies or that it never will be persuaded that recognition of MDS is proper.

**Q HAS THE COMMISSION EVER ADOPTED AN ECOS STUDY THAT INCLUDED THE USE OF AN MDS METHOD BY ANY FLORIDA UTILITY?**

A Yes. In Order No. PSC-02-1169-TRF-EC, issued in Docket No. 020537-EC on August 26, 2002, the Commission approved rates for CHELCO that were based on an ECOS study which used the "zero-intercept" method to estimate the MDS costs, and allocated them based on the number of customers.

In addition, I am aware of a rate settlement in the recent Gulf Power Company rate case, Docket No. 110138-EI, which was based on cost of service results that recognized the MDS and allocated associated costs on a customer basis.

**Q WHY DID THE COMMISSION APPROVE THE USE OF AN MDS METHOD FOR CHELCO WHEN IT GENERALLY HAD NOT ALLOWED SUCH USE FOR IOUS?**

A In its Order No. PSC-02-1169-TRF-EC, the Commission stated:

> "In the past 20 years, we have consistently rejected the use of the MDS classification methodology by investor-owned utilities. In this case, however, we find that CHELCO has four unique characteristics that justify the use of the MDS classification methodology in its cost of service study." (Choctawhatchee Electric Cooperative, Inc., Order No. PSC-02-1169-TRF-EC, issued August 26, 2002 in Docket No. 020537-EC, page 3).

The first unique characteristic identified by the Commission was that "CHELCO has a density of ten customers per mile, while most investor-owned utilities have a density of fifty-five customers per mile or greater." (*Id.*). The Commission's Order also states:

> "In a high-density service territory, several customers may be served by a single transformer, while in a sparsely populated rural area there is usually one transformer for each residential account. Thus, the significant costs of constructing and maintaining a mile of line in a rural service territory are spread to a significantly fewer number of customers." (*Id.* page 4).

**Q DO YOU WISH TO COMMENT ON THE COMMISSION'S STATED RATIONALE?**

A Yes. There are a couple of problems with using relatively low customer densities as a basis for approving an MDS. First, it is counterintuitive. The customer densities of the IOUs suggest that, on average, "most" IOUs have incurred the cost of connecting an additional customer five and a half times more frequently than CHELCO. This implies that the customer-related costs incurred to connect customers to the system will be much higher for the IOUs than for CHELCO. In other words, most IOUs will incur the costs of transformers and secondary voltage circuits five times as often as CHELCO does. It is unclear, therefore, why CHELCO's relatively low customer density justifies its use of MDS methods, but the much more frequent incurrence of customer-related costs of "most" IOUs does not.

More importantly, I am unaware of any other instances where a Commission has based adoption of the MDS method on the customer density of one utility relative to another. Indeed, the Commission's allowance of the MDS method in the case of CHELCO demonstrates, at the very least, that the Commission is aware that some portion of the primary and secondary distribution system costs, other than those related to services and meters is customer-related. Furthermore, the Commission's acceptance of CHELCO's zero-intercept analysis shows that it also recognizes the usefulness of such analyses to estimate this customer-related portion.

**Q WHAT IS THE SECOND UNIQUE CHARACTERISTIC OF CHELCO THAT THE COMMISSION IDENTIFIED?**

A The second unique characteristic identified by the Commission was that "CHELCO's rural service territory is quite different from an urban investor-owned utility." The Commission explains in its order:

> "Urban areas are normally occupied throughout the year, and customers usually consume a large amount of electricity that varies seasonally with their heating and cooling load. By contrast, CHELCO provides service to a significant number of barns, stock tanks, electric fences, hunting cabins, and vacation homes. These types of customers consume small amounts of electricity during the course of the year, and their usage is sporadic. A rate design with a relatively low customer charge and a high energy charge for these customers may not recover the costs of investment necessary to serve their load." (*Id.*).

This explanation is surprising in that it begins by describing how perceived differences between rural and urban service territories pertain to the MDS method, yet then draw a conclusion about measuring cost, an empirical determination, on a decision about rate design. Nothing is said to address how urban/rural territory differences negate the importance of the MDS in one case, or increase the importance of the MDS in the other. Furthermore, the comments regarding rate design appear out of place since the MDS is specific to the ECOS study and therefore precedes, but is otherwise unrelated to the rate design process.

## Reasons for Past Commission Failure to Adopt of MDS

**Q GIVEN THAT THE COMMISSION HAS APPROVED THE USE OF MDS METHODS FOR AN ELECTRIC COOPERATIVE, WHAT REASONS HAS THE COMMISSION GIVEN IN REJECTING THE USE OF MDS METHODS FOR IOUS IN PAST CASES?**

A The Commission's objections to the MDS have been numerous and varied. In its June 10, 2002 order (Order No. PSC-02-0787-FOF-E1) issued in regard to FPL's 2002 rate case (Docket No. 010949-E1), the Commission rejected the use of the MDS after providing the following explanations:

1. Although utility and intervenor witnesses relied on the NARUC Manual to support the use of MDS, the NARUC Manual's stated purpose shows it was designed to educate regarding various cost allocation methods, not mandate any particular method.

2. FPL provided no evidence on the specific circumstances that made it choose the MDS methodology over the method approved by the Commission in FPL's previous rate case.
3. The MDS methodology requires construction of a hypothetical system consisting of equipment that is designed to carry zero load. Therefore, no real equipment equates to the costs identified by the zero-intercept methodology. The Commission has rejected MDS in the past for this very reason.
4. Prior orders by the Commission show that it was the MDS's theoretical construct with which the Commission disagreed, not the end result of ECOS studies that use MDS methods.
5. The MDS is internally inconsistent in that it separates out distribution facilities for different treatment than transmission lines.

These are just a subset of the arguments against the MDS that the Commission has accepted over the last 30 years. Indeed, the Commission has not only rejected MDS proposals from FPL, but has also rejected MDS proposals from the Commission Staff, Florida Industrial Power Users Group, South Florida Hospital and Healthcare Association, Tampa Electric Company, and Florida Power Corporation.[5] Unfortunately, there are logical or inapplicable problems with each of the reasons previously relied on by the Commission.

[5]It is noteworthy that the Commission did not raise these objections in approving the rate settlement in the previously mentioned Gulf Power Company case.

**Q DOES THE MDS METHODOLOGY REQUIRE CONSTRUCTION OF A HYPOTHETICAL SYSTEM CONSISTING OF EQUIPMENT THAT IS DESIGNED TO CARRY ZERO LOAD?**

A No. The notion that the MDS is designed to carry no load is an over-simplification, and is also something of a straw-man argument. A better description of the MDS is that it reflects the smallest, lowest cost distribution system that *must be installed for the utility to meet its obligation to provide service to its customers*, but does not contain costs incurred to meet the customer's peak load. Therefore, the MDS methodology only requires the analyst to identify the electric system components that must be installed to meet whatever construction, safety and/or reliability standards are enforced by the governing authorities at the time the line is installed. Costs for meeting system demand above these minimum levels are properly allocated on demand, as FPL has done.

The most realistic and accurate concept of the MDS is that it consists of the network of electric lines that conform to the NESC requirements described in the F.A.C.

**Q IS THE MDS INTERNALLY INCONSISTENT IN THAT IT SEPARATES OUT DISTRIBUTION FACILITIES FOR DIFFERENT TREATMENT THAN TRANSMISSION LINES?**

A No. It is universally understood that any electric system that carries electricity from the generator to the customer must contain transmission, sub-transmission, and distribution components. However, it is also widely recognized that the customer-related portion of costs steadily decreases as one moves away from the end-use customer toward the generator. At the transmission level, the customer-related portion of costs is generally low.

For example, at the meter, the customer-related portion of costs is 100%. Likewise, the customer-related portion of service costs is also 100%. However, the customer portion of costs drops significantly at the level of primary distribution lines. Although the MDS approach could be applied to transmission lines as well, the impact of any reallocation likely would be minor and would not justify the complexity of the additional analysis.

**Q PLEASE DESCRIBE THE NESC STANDARDS THAT THE COMMISSION ADOPTED IN THE F.A.C.**

A F.A.C. Rule 25-6.0345 – Safety Standards for Construction of New Transmission and Distribution Facilities states:

> "The Commission adopts and incorporates by reference the 2002 edition of the National Electrical Safety Code (ANSI C-2) [NESC], as the applicable safety standards for transmission and distribution facilities subject to the Commission's safety jurisdiction. For electrical facilities constructed on or after February 1, 2007, the 2007 NESC shall apply. Electrical facilities constructed prior to February 1, 2007, shall be governed by the edition of the NESC specified by subsections 013.B.1, 013.B.2, and 013.B.3 of the 2007 NESC. Each investor-owned electric utility, rural electric cooperative and municipal electric system shall, at a minimum, comply with the standards in these

> provisions." (F.A.C. Rule 25-6.0345, subpart (1), emphasis added).

**Q WHAT IS THE PURPOSE OF THE NESC?**

A Section 1, Part 010, of the NESC states:

> "The purpose of these rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and their associated equipment. They contain minimum provisions considered necessary for the safety of employees and the public. They are not intended as a design specification or an instruction manual." (Emphasis added).

**Q DOES THE NESC ALSO ESTABLISH STANDARDS FOR THE ELECTRICAL DEMAND EACH COMPONENT MUST BE CAPABLE OF CARRYING?**

A Not directly. To my knowledge, the only situation where the NESC covers something like this is in the case of grounding wires where the NESC sets the "short time ampacity adequate for a fault current."[6] Yet even here, the purpose of the grounding wire is to provide safety or enhance reliability rather than to serve electrical load.

[6]Section 9, Subsection 93.C., Ampacity and Strength.

**Q ARE MDS METHODS USED FOR ALLOCATING DISTRIBUTION COSTS IN OTHER STATES?**

A Yes, it is not uncommon outside of Florida. Our firm's research indicates that MDS methods are currently, or have been approved by at least 17 state commissions.

**Q WHAT DO YOU RECOMMEND?**

A The Commission should require FPL to use the zero-intercept method to estimate the customer-related costs associated with the Company's primary and secondary distribution system in its next rate case. By recognizing the MDS in its ECOS study, FPL will obtain a reasonable, yet understated, estimate of costs associated with the MDS. Based on MDS studies by other utilities and in other jurisdictions, it is reasonable to expect that FPL would find that the customer-related component of the distribution system to be in the neighborhood of 35% to 40%, with the remainder being demand-related. Failure to recognize the MDS at all implicitly assumes zero percent, which is arbitrary and unreasonable as an estimate.

## RATE DESIGN

**Q HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE DESIGN AND THE ASSOCIATED TESTIMONY?**

A Yes. This topic is addressed by FPL witness Renae B. Deaton.

**Q DO YOU TAKE ISSUE WITH ANY OF THE PROPOSED BASE RATE DESIGN IN THIS PROCEEDING?**

A Yes. The Company's class impact moderation method should be applied differently.

**Q HOW DO YOU PROPOSE TO APPLY THE RATE MODERATION APPROACH DIFFERENTLY?**

A I propose to alter the rate increase moderation methodology employed by the Company and described in Ms. Deaton's testimony. The Company calculates the 1.5x system average increase cap based on the total increase to each class, including adjustment clauses. Yet, this case involves increases in base rates only, and the adjustment clauses are not affected by decisions in this case. Allowing for the inclusion of adjustment clause revenue impedes somewhat the goal of efficiently and equitably bringing classes closer to parity because it distorts the view of which classes deserve the greatest rate increases according to the Company's cost of service study. It also dilutes the rate moderating effect of the mitigation criterion.

**Q PLEASE EXPLAIN WHY INCLUDING ADJUSTMENT CLAUSE REVENUE IN THE RATE MODERATION PROCESS IMPEDES SOMEWHAT THE GOAL OF EFFICIENTLY AND EQUITABLY BRINGING CLASSES CLOSER TO PARITY.**

A As alluded to early in this testimony, one of the purposes of a class cost of service study is to be used as a basis for rate design to ensure that the total revenue increase requested by the Company is properly allocated to those classes that are currently being subsidized by other classes. In this rate proceeding, only the base rate revenue is being investigated, and only the base rate revenue was included in the cost of service studies performed. The results of these studies tell us which classes are most deserving of a rate increase. If, then, the resulting revenue increases are adjusted and re-allocated based on a metric that includes non-base rate revenue, the view of which classes are most deserving of a rate increase gets distorted.

**Q PLEASE EXPLAIN WHY INCLUDING ADJUSTMENT CLAUSE REVENUE IN THE RATE MITIGATION PROCESS DILUTES THE RATE MITIGATING EFFECT OF THE MODERATION CRITERION.**

A Two of the basic tenets of sound rate design are to promote gradualism and the avoidance of rate shock. The 1.5x system average increase cap clearly is a step toward this goal. Since the adjustment clause revenues are not at issue in this case, the only rates that need to be increased gradually, in order to avoid rate shock are the base rates. Other costs, such as the adjustment charges, or even other costs that might be faced by a customer (e.g., natural gas) are not as relevant. Therefore, rate moderation criteria are most effective if applied to only those charges that are subject to change in this case, i.e., base rate charges.

**Q WHAT IS YOUR SUGGESTED ALTERNATIVE TO THE COMPANY'S RATE MITIGATION PROCESS?**

A As opposed to calculating the maximum revenue increase allowed, and redistributing the revenue shortfall to classes based on the total proposed increase including adjustment clause revenue, I propose to follow the Company's process, except to utilize the proposed base-rate-only increase. Exhibit RRS-1 shows the effects of this adjustment on all rate classes.

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

A Yes, it does.

## Qualifications of Robert R. Stephens

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

A Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q PLEASE STATE YOUR OCCUPATION.**

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

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I graduated from Southern Illinois University at Carbondale in 1984 with a Bachelor of Science degree in Engineering. During college, I was employed by Central Illinois Public Service Company in the Gas Department. Upon graduation, I accepted a position as a Mechanical Engineer at the Illinois Department of Energy and Natural Resources. In the summer of 1986, I accepted a position as Energy Planner with City Water, Light and Power, a municipal electric and water utility in Springfield, Illinois. My duties centered on integrated resource planning and the design and administration of load management programs.

From July 1989 to June 1994, I was employed as a Senior Economic Analyst in the Planning and Operations Department of the Staff of the Illinois Commerce Commission. In this position, I reviewed utility filings and prepared various reports and testimony for use by the Commission. From June 1994 to August 1997, I worked directly with a Commissioner as an Executive Assistant. In this role, I provided technical and policy analyses on a broad spectrum of issues related to the electric, gas, telecommunications and water utility industries.

In May 1996, I graduated from the University of Illinois at Springfield with a Master of Business Administration degree.

In August 1997, I joined Brubaker & Associates, Inc. as a Consultant. Since that time, I have participated in the analysis of various utility rate and restructuring matters in several states and the evaluation of power supply proposals for clients. I am currently a Principal in the firm.

The firm of Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients, including large industrial and institutional customers, some utilities, and on occasion, state regulatory agencies. More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate, feasibility, economic and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services; and provide technical support to legislative activities.

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

CAPT. MILLER: I would also like to move Mr. Stephens' exhibits, identified as 371 and 372 into the record.

COMMISSIONER BROWN: Any objections?

MR. RUBIN: No objections.

COMMISSIONER BROWN: Seeing none, Exhibits 371 and 372 will be entered into the record. Okay?

(Exhibits 371 and 372 admitted in evidence.)

MR. YOUNG: Madam Chairman, that ends the Federal Executive Agency's direct case. The next one, Algenol, it is my understanding that counsel for Algenol has communicated with Staff that they would like to withdraw R. Paul Woods' testimony. He does not have any exhibits attached to that testimony.

COMMISSIONER BROWN: Okay. We will withdraw Mr. Woods' testimony, with no exhibits.

MR. YOUNG: Next, Staff would just note that Mr. Hendricks and Mr. Saporito have already testified, and we are now on Staff's witnesses, which have been stipulated.

And at this time Staff would like to move the prefiled direct testimony of Kathy L. Welch into the record.

COMMISSIONER BROWN: Okay. Any objections?

MR. RUBIN: No objections.

COMMISSIONER BROWN: We will move Kathy Welch's prefiled direct testimony into the record.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**COMMISSION STAFF**

**DIRECT TESTIMONY OF KATHY L. WELCH**

**DOCKET NO. 120015-EI**

**JULY 16, 2012**

Q. **Please state your name and business address.**

A. My name is Kathy L. Welch, and my business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

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

A. I am employed by the Florida Public Service Commission as a Public Utilities Supervisor in the Office of Auditing and Performance Analysis.

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

A. I have been employed by the Florida Public Service Commission since June, 1979.

Q. **Briefly review your educational and professional background.**

A. I have a Bachelor of Business Administration degree with a major in accounting from Florida Atlantic University and a Masters of Adult Education and Human Resource Development from Florida International University. I have a Certified Public Manager certificate from Florida State University. I am also a Certified Public Accountant licensed in the State of Florida, and I am a member of the American and Florida Institutes of Certified Public Accountants. I was hired as a Public Utilities Analyst I by the Florida Public Service Commission in June of 1979. I was promoted to Public Utilities Supervisor on June 1, 2001.

Q. **Please describe your current responsibilities.**

A. Currently, I am a Public Utilities Supervisor with the responsibilities of administering the District Office and reviewing work load and allocating resources to complete field work and issue audit reports when due. I also supervise, plan, and conduct utility audits of manual and automated accounting systems for historical and forecasted data.

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

**A.** Yes. I have testified in several cases before the Florida Public Service Commission. Exhibit KLW-1 lists these cases.

**Q. What is the purpose of your testimony today?**

**A.** The purpose of my testimony is to sponsor the staff audit report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 120015-EI Petition for increase in rates. We issued an audit report in this docket on June 28, 2012. This audit report is filed with my testimony and is identified as Exhibit KLW-2.

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

**A.** Yes, it was prepared under my direction.

**Q. What audit period did you use in this audit?**

**A.** The historical year ended December 31, 2011 is the audit period unless otherwise specified.

**Q. Please describe the work you performed in this audit?**

**A.** I have broken the audit work into the following categories.

## General

We obtained a 13-month trial balance that reconciled to the Utility's general ledger and traced it to the Minimum Filing Requirements (MFRs) for rate base, net operating income, and capital structure.

Audit staff reconciled the adjustments to rate base and net operating income from the MFRs to the general ledger or other supporting documentation to verify that the adjustments for the audit period were consistent with the Commission's findings in prior cases. We verified that all necessary adjustments were made and that they were correctly calculated based on past orders or rules.

## Rate Base

Utility Plant in Service

Audit staff obtained a schedule by plant and reserve accounts by month for the historical test year ended December 31, 2011 with 13-month average balances. We traced this schedule to the trial balance and the MFRs. We also obtained a schedule of plant balances by detailed account from January 1, 2009 to March 31, 2012 and traced it to the trial balance and the MFRs. We judgmentally selected work orders added since the last rate case and traced additions, retirements, and adjustments, including the Cape Canaveral Modernization, to supporting documentation. In addition, we traced the journal entries for the sale of the general office in Miami and the aircraft transfer to source documents. We reviewed the transactions related to the sale of the general office.

Accumulated Depreciation and Amortization

We reconciled the Utility's books to the MFR for the historical test year. We reconciled the annual accumulated depreciation and amortization accruals to the Utility's books. We reconciled depreciation and amortization rates to Order No. PSC-10-0153-FOF-EI in Docket Nos. 080677-EI and 090130-EI issued March 17, 2010. We also selected a sample of adjustments made by the Utility and reviewed the source documents.

Construction Work in Progress

We obtained a list of projects included in CWIP, which were eligible for AFUDC according to Rule 25-6.0141, Florida Administrative Code. We recalculated AFUDC for the work orders tested. We also obtained a list of projects included in CWIP that were not eligible for AFUDC and verified that the projects were not eligible according to the rule. We noted that the Utility is not requesting AFUDC-eligible CWIP in rate base.

Working Capital

We reviewed the accounts included in working capital for items that may earn interest. We reviewed the interest income and interest expense accounts, and verified that either the interest accrued on these accounts was also included or the account was removed from working capital.

We determined which of the prepayments, deferred debits, and deferred credits accounts were included in working capital, and then selected accounts with material balances. Audit staff judgmentally sampled these accounts, traced items to source documentation, verified to determine they were utility-related, and appropriately included in working capital.

We judgmentally sampled accounts 228.1 – Accumulated Provision for Property Insurance, 228.2 – Accumulated Provision for Injuries and Damages, and 228.4 – Accumulated Miscellaneous Operating Provisions. We traced transactions to source documentation, determined the items were utility-related, and determined if they were appropriately included in working capital.

## Net Operating Income

Operating Revenue

We reconciled the monthly revenues in the MFRs to the Utility's books. We recalculated a judgmental sample of customer bills and traced the rates to the appropriate clause factors and tariffs. We traced the unbilled revenue for the audit period to the MFRs and the general ledger. We reviewed the unbilled calculation.

Operation and Maintenance Expense

Audit staff prepared an analytical review of the Utility's expenses. We compared the expenses from 2008 to 2011 noting any large increases in accounts. We selected a judgmental sample based on the analytical review and tested to see if the transactions were adequately supported, and recorded in compliance with the Uniform System of Accounts (USOA).

We selected a judgmental sample from the advertising account for the historical test year and reviewed the advertisements to determine if they are image enhancing in nature, promotional, or related to non-utility operations or one of the recovery clauses.

We selected a judgmental sample of legal fees, other outside service expenses, sales expenses, customer service expenses, office supplies and expense, and miscellaneous general expenses. We tested the transactions to see that they were reasonable, adequately supported, and recorded in compliance with the USOA.

We selected a sample of liability, health and life insurance expense during the audit period and verified the expense to invoices in conjunction with the prepaid account. We also verified that the utility included refunds as a credit to the expense account.

We traced the uncollectible provision and expense accounts to the Utility's ledger and the MFRs. We also reviewed the components of the provision balance and reconciled the provision to the expense account. We noted that the reserve balance decreased $9,452,264 during the historical year due to the elimination of a special provision program. In addition, the uncollectible account expense decreased $8,795,237 or 55% since 2006.

Depreciation Expense

We obtained depreciation schedules, reconciled them to the general ledger and the MFRs. We compared the rates used to Order No. PSC-10-0153-FOF-EI in Docket Nos.

080677-EI and 090130-EI, issued March 17, 2010.

Taxes Other than Income

We reconciled the monthly sales tax returns to the Utility's books. We recalculated the returns for selected months for mathematical accuracy. We reviewed the recorded entries and concluded that the collection discount was recorded above the line.

We traced the MFR schedule for taxes other than income to the general ledger and reconciled it to the applicable tax returns.

Income Taxes

We traced the federal and state income taxes from the filing to the Utility's books. The 2011 tax returns had not been filed at the time the report was written. We traced the deferred income tax expense and the deferred tax balances to the books and the deferred tax reports.

## Capital Structure

We obtained the rate base/capital structure reconciliation and determined that the non-utility adjustments removed in rate base were removed in the capital structure. We obtained a 13-month average trial balance from the Utility's general ledger and reconciled it to the cost of capital MFRs.

Audit staff reconciled the cost of capital cost rates for the audit period to the debt documentation. We obtained a reconciliation of the rate base adjustments in the capital structure and traced it to the MFRs and the general ledger.

## Other

Affiliate Transactions

Audit staff reviewed the Utility's policies and procedures relating to the recording of affiliate transactions and the cost/allocation manual for employees. During the review of rate base and net operating income, we examined items that were allocated and compared them to the Utility's policies and procedures. We obtained supporting documentation from several of the affiliates and reviewed the allocation methodology. We reviewed the calculation of the management fee and the drivers used and compared the methodology and rates to the last rate case audit. We traced the budget activity to the actual ledger amounts. We reviewed charges to FPL to determine if they were charged at the lower of cost or market or based on prior Commission orders. We obtained a list of space rented to affiliates by building, square footage and cost per square foot and compared the rent charged to the Market Rent Valuation. We reviewed the Diversification Report and judgmentally selected a sample of officers of both FPL and its affiliates and reviewed the allocation percents of these officers to determine reasonableness based on their duties.

Federal Energy Regulatory Commission Audit

We read the FERC audit, dated October 10, 2008, pertaining to the audit of Open Access Same-Time Information System Requirements and determined that FPL implemented the corrective action that was required.

Internal and External Audits

We reviewed the internal and external audits to determine if any adjustments materially affected the audit period. We noted that the Utility had performed the required corrective action in the applicable follow-up audit.

**Q. Please review the audit findings in this audit report, Exhibit KLW-2.**

**A.** There were six findings in this audit as follows:

**Finding 1: Executive Compensation Adjustment**

The Utility removed $28,402,000 from Net Operating Income related to an adjustment to Executive Compensation and Non-Executive Performance Shares, based on Order No. PSC-10-0153-FOF-EI in Docket Nos. 080677-EI and 090130-EI, issued March

17, 2010. In determining the amount we noted that the January 2011 amount of $213,000 for the Non-Executive Performance shares was not included in the schedule. Therefore, the adjustment to remove executive compensation was understated by $213,000 and operating expenses should be reduced by $213,000 in the historic test year.

**Finding 2: Possible Non-Recurring Expenses**

We selected samples of accounts in the historic 2011 year based on an analytical review. In our sample, we determined that some expenses may not be re-occurring and should be reviewed in conjunction with Tallahassee staff's review of the 2013 forecast.

1. In December of 2011, there was a write-off of $10,405,707.28 to account 930.2 of FPL' Energy Secure Pipeline. FPL's forecast of account 930.2-Miscellaneous General Expense decreased in 2013 by $8,728,400, from $27,044,400 in 2011 to $18,316,000 in 2013. Therefore, it appears that FPL removed the $10,405,707 in its forecast for 2013 but provided other costs that increased. Most of the difference related to an increase of $2.7 million for industry dues in 2013. The additional dues should be reviewed in conjunction with the 2013 forecast.

2. In December of 2011, an entry of $144,667.03 was made to account 572-Maintenance of Underground Lines that related to 2009 costs that had been in a completed not classified account and were being written off to expense in 2011. These costs should not be re-occurring and the 2013 forecast review should insure that they were removed.

3. In October of 2011, there was an entry of $227,525.76 to account 560-O & M Transmission Maintenance for transmission line data gathering in response to a 2010 NERC audit. There may be additional costs in 2011 related to this project. Whether these charges are re-occurring should be reviewed in conjunction with the forecast.

4. In 2011, the sample of account 902-Meter Reading included several invoices related to the Advanced Metering Infrastructure (AMI). Some of these costs were offset by a Department of Energy grant. Since some of the costs related to production and integration, there may be many costs related to this project that are not re-occurring. For example, there was a $340,246.34 charge for severance pay for meter reading employees who were let go because of the system that would not be re-occurring. There was an invoice of $104,005 for system integration activities and $38,149 for production software support. According to a response by FPL, total AMI expenses in 2011 were $14,700,000 and capital costs were $203,200 net of the Department of Energy grant. The review of the 2013 forecast should determine if it has been reduced for AMI related costs that are not re-occurring.

5. In July 2011, FPL switched from its Walker accounting system to a SAP accounting system. In our sample, we found invoices related to computer software integration. FPL provided a budget report showing the Information Management expense budget was reduced by $2,037,081 for costs related to the SAP project. The Tallahassee staff should review the 2013 forecast to determine that other costs related to implementation of SAP such as training are removed.

6. The sample of account 923-Outside Services in 2011 included legal and accounting invoices totaling $101,402 related to the negotiations to purchase the utility system from the City of Vero Beach. Tallahassee staff should determine if these and any additional costs related to the purchase were removed from the forecast.

7. The sample of account 923-Outside Services in 2011 included $108,427 related to studies of customer satisfaction. Tallahassee staff should determine if these and any additional costs related to the studies will be re-occurring in 2013.

**Finding 3: Training**

Three invoices related to training of employees were selected in the sample. Each class included employees from affiliate companies. The dollar effect of the adjustment, $3,631, is immaterial to this filing in 2011. However, training costs should be allocated to the affiliate companies based on number of participants and only three trainings were selected as part of the sample.

FPL has responded that it pays in full for the invoice, review on a monthly basis, and charge the appropriate affiliate for each participant. However, the affiliates were not charged for the three invoices in the sample.

**Finding 4: Patents**

An invoice in the sample of account 923-Outside Services included patent and trademark litigation related to patents obtained by FPL. They included patent litigation related to the following:

1. A boom truck patent.

2. Filing of a patent related to the development of an innovation related to automated meter reading technology.

3. Due diligence and prosecution work for an FPL Power Generation business unit invention of a rotational blade predictive heat monitor.

4. Patent prosecution work for an FPL Distribution invention of a boom radiography test device.

5. Patent prosecution work for an FPL Power Generation business unit invention of a matrix model builder.

6. Patent prosecution work for an FPL Power Generation business unit invention of a combustion turbine inlet filter.

7. Patent prosecution work for an invention by an FPL Distribution business unit on distribution situational awareness.

The Tallahassee staff should insure that revenues or other benefits received related to the patents developed by the Utility stay with the Utility.

**Finding 5: FiberNet**

FiberNet charges FPL for depreciation and a return on investment for property transferred from FPL to FiberNet in the year 2000. FPL has adjusted the return on these assets in 2011 based on Order No. PSC-10-0153-FOF-EI in Docket Nos. 080677-EI and 090130-EI, issued March 17, 2010. The total charge in the historic 2011 test year of $6,857,570, before the ordered adjustment, included an amount for $109,589 which the Utility says is a one-time non-recurring charge. The charge is taxed by approximately 11% for a taxed amount of $121,644. FPL allocates 83.54% to base operating and maintenance expense or $101,621. The rest is charged to conservation and a plant clearing account.

Although plant has been added, this charge of $6,857,570 to FPL has decreased since our audit done in 2000 and will probably continue to decrease due to the additional accumulated depreciation. Therefore, the forecast for 2013 should have included a reduction of $101,621 for the non-recurring costs and an additional decrease for the return on an additional $1,217,697 of accumulated depreciation a year if no additions are forecast.

FPL is also charged for Data Line Charges that are not part of the 2000 transfer of assets audited. The Utility provided support to show that these charges are lower than market.

This information should be reviewed in conjunction with the Tallahassee staff's review of the 2013 test year forecast.

**<u>Finding 6: Budget Unit Not In Management Fee Allocation</u>**

An amount of $161,431 was charged to Budget Activity Code 11717 which was excluded from the calculation of the management fee. According to a response from the Utility, this amount was charged to that budget activity in error and should have been charged to Budget Activity Code 10422 or 11686 which are allocated to the affiliates using 33.60% in 2011. Therefore, an additional $54,241 should have been credited to account 922 and debited to a receivable from the affiliate companies' account 146. Operating Expenses for the historic 2011 test year should be reduced by $54,241.

**Q. Does that conclude your testimony?**

**A.** Yes.

MR. YOUNG: Along with that, Madam Chairman, Ms. Welch had some exhibits attached to her prefiled direct testimony. That's exhibits starting on 391 and 392. As stated earlier during the course of this hearing, part of the stipulation is that Ms. Welch's deposition be moved into the record. That's Exhibit Number 120.

COMMISSIONER BROWN: 120. Okay, are there any objections?

MR. RUBIN: No objections from FPL.

COMMISSIONER BROWN: Anyone? We will move Ms. Welch's prefiled direct, Exhibits 391 and 392, as well as her deposition, 120, into the record. All right. Ms. Hicks?

(Exhibits 120, 391 and 392 admitted in evidence.)

MR. YOUNG: Next, another Staff -- another Staff witness, Ms. Rhonda L. Hicks, as agreed upon by the parties, that she is stipulated and the Commissioners have no questions for Ms. Hicks. So at this time we ask that the prefiled direct testimony of Ms. Hicks be entered into the record.

COMMISSIONER BROWN: Any objections?

MR. RUBIN: No objections.

COMMISSIONER BROWN: We will enter Ms. Hicks' prefiled direct testimony into the record.

AMENDED 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) as Chief of the Bureau of Consumer Assistance in the Office of Consumer Assistance and Outreach.

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 Florida Public Service Commission for 26 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 Office of Consumer Assistance and Outreach 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 Florida Power and Light Company under Rule 25-22.032, Florida Administrative Code, Consumer Complaints, from July 1, 2009 through June 30, 2012. 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 Florida Power and Light Company?

A. From July 1, 2009, through June 30, 2012, the Florida Public Service Commission logged 19,434 complaints against Florida Power and Light Company. Of those, 16,200 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 Florida Power and Light Company?

A. During the specified time period, approximately seventy percent (13,644) of the complaints logged with the Florida Public Service Commission concerned billing issues, while approximately thirty percent (5,570) of the complaints involved quality of service issues.

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

A. Yes. I am sponsoring Exhibit RLH-1.

Q. Would you explain Exhibit RLH-1?

A. Yes. Exhibit RLH-1 is a summary listing of complaints logged against Florida Power and Light Company under Rule 25-22.032, Florida Administrative Code. The complaints, received July 1, 2009 through June 30, 2012, 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 has no Close Type because they are pending complaints. The remaining groupings are categorized by Close Type codes such as EB-23, ES-21, GI-02, 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. Florida Power and Light Company 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 Florida Power and Light Company, 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 Florida Power and Light Company. 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 the 19,434 complaints, staff determined that four appear to be violations of Commission rules.

Q. What was the nature of the apparent rule violations?

A. The apparent rule violations were failure to respond to the customer (ES-49), improper billing (EB-23, EB-24), and service quality (ES-21).

Q. Does this conclude your testimony?

A. Yes, it does.

MR. YOUNG: Along with her prefiled direct testimony, Madam Chairman, Ms. Hicks had one exhibit, Number 393. We ask at this time that that exhibit be moved into the record.

COMMISSIONER BROWN: Seeing no objections, I will move Exhibit 393 into the record.

(Exhibit 393 admitted in evidence.)

COMMISSIONER BROWN: Okay. So now we are on rebuttal?

MR. YOUNG: Yes, ma'am.

MR. SAPORITO: I --

MR. YOUNG: I'm sorry?

MR. SAPORITO: I just need clarification. The Hicks prefiled testimony, is there an exhibit number to that?

MR. YOUNG: Yes, sir, it's 393.

MR. SAPORITO: And there was one before, a deposition or something you all moved. What was the number of that?

MR. YOUNG: 120.

MR. SAPORITO: Thank you.

COMMISSIONER BROWN: We move quickly.

MR. YOUNG: With that, Madam Chairman, we have concluded all the parties direct testimony, and we are now on FPL's rebuttal testimony.

COMMISSIONER BROWN: Great.

MR. RUBIN: May I proceed, Madam Chair?

COMMISSIONER BROWN: Yes, please.

Thereupon,

ROSEMARY MORLEY

was called as a rebuttal witness on behalf of Florida Power & Light, having been previously duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. RUBIN:

Q Good afternoon, Dr. Morley.

COMMISSIONER BROWN: Oh, pardon me -- oh, she was sworn. That's right.

MR. RUBIN: She was sworn last week.

COMMISSIONER BROWN: That's right.

MR. RUBIN: I'll ask her on the record, just to confirm.

BY MR. MORLEY:

Q Good afternoon Dr. Morley.

A Good afternoon.

Q You were sworn here before the Commission when you testified on direct last week, correct?

A Correct.

Q And you understand that you're still under oath, correct?

A Correct.
Q Can you just remind the Commission of your name, business address, and the company by whom you're employed?
A Yes. Rosemary Morley, and I'm employed as the Director of Load Forecasting at Florida Power & Light.
Q Have you prepared and caused to be filed nine pages of prefiled rebuttal testimony in this proceeding on July 31, 2012?
A Yes, I have.
Q Do you have any changes or revisions to your prefiled rebuttal testimony?
A No, I do not.
Q If I asked you the same questions contained in your prefiled rebuttal testimony, would your answers be the same?
A Yes.

MR. RUBIN: Madam Chairman, I would ask that the prefiled rebuttal testimony of Dr. Morley be inserted into the record as though read.

COMMISSIONER BROWN: Seeing no objections, we will -- I will Dr. Morley's prefiled rebuttal testimony into the record as though read.

MR. RUBIN: Thank you.

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Dr. Rosemary Morley. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420.

**Q. Did you previously submit direct testimony in this proceeding?**

A. Yes.

**Q. Are you sponsoring any rebuttal exhibits in this case?**

A. Yes. I am sponsoring the following rebuttal exhibits:

- RM-3, Comparison of Rolling 10 and 20 Year Average Annual Cooling Degree Hours (2000 – 2011)
- RM-4, Annual Cooling Degree Hours (1992 – 2011)

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to refute South Florida Hospital and Healthcare Association ("SFHHA") witness Baron's proposed use of only 10 years as the basis for his calculation of normal weather conditions for the purpose of forecasting electric sales. SFHHA witness Baron proposes to inappropriately limit the data used in calculating normal weather conditions rather than relying on a multi-decade horizon that has traditionally been approved in Florida.

**Q. Please summarize your rebuttal testimony.**

A. I demonstrate that a 10 year time period, as proposed by SFHHA witness Baron, is an unreasonably short time period to calculate normal weather conditions. Using only 10 years of data would result in a volatile and unreliable definition of normal weather conditions. Moreover, limiting the calculation of the normal weather conditions to only 10 years of data is inconsistent with FPL's long-term generation planning and with the load forecasts approved for the other major electric utilities in Florida. Indeed, the Florida Public Service Commission ("FPSC") has consistently relied on a multi-decade horizon to calculate normal weather. Mr. Baron's proposal would represent an abrupt and potentially far-reaching break with this Commission's past practice.

## II. WEATHER NORMALIZATION

**Q. How does FPL calculate normal weather conditions in developing its load forecast?**

A. In developing its load forecast FPL calculates normal weather conditions based on the average weather conditions experienced over the last 20 years.

**Q. Does SFHHA witness Baron take issue with using 20 years of data to calculate normal weather conditions?**

A. Yes. SFHHA witness Baron proposes to use only 10 years of data on cooling degree hours to calculate normal weather conditions.

**Q. What rationale does SFHHA witness Baron present for using only 10 years of history to calculate normal weather conditions?**

A. None. SFHHA witness Baron offers no rationale for using only 10 years of history to calculate normal weather conditions. He merely observes that using 10 years of data to calculate the normal level of cooling degree hours would result in a higher sales forecast and these "additional revenues would, all else being equal, have helped offset some of the Company's revenue deficiency in this case." Thus, one is left with the impression that SFHHA witness Baron is not presenting a carefully developed alternative weather assumption, but an arbitrary means of raising the load forecast with the objective of reducing FPL's rate request. This is not a sound basis for altering the load forecast.

**Q. Would the use of only 10 years of data to calculate normal weather conditions have implications beyond the pending case?**

A. Yes. Use of a 10 year rather than a 20 year horizon to calculate normal weather conditions would have lasting implications well beyond the pending case. A decision to base normal weather conditions on only 10 years of data would impact a variety of proceedings including those addressing the need determination of new generation resources and Demand-Side Management goals.

**Q. Does the evidence support the use of a 20 year horizon to calculate normal weather?**

A. Yes. A 20 year horizon incorporates the most recently available weather data while also encompassing a sufficient period of time to capture long-term weather trends. By contrast, a 10 year horizon is an unreasonably short period of time to use in calculating normal weather conditions. A 10 year period increases the likelihood that one or two non-representative years will skew the definition of normal weather. The use of a 10 year period to calculate normal weather would also create a much more volatile set of weather assumptions incorporated into the load forecast.

**Q. Can the use of a multi-decade period to calculate normal weather be compared with the need to have an adequately large sample size in statistics?**

A. Yes. In statistics, one of the principal problems with a sample size that is too small is that it may not be representative of the population as a whole. Likewise, using only 10 years of data to define normal weather increases the likelihood that one or two non-representative years may skew the results. As we all know, weather is inherently variable. In fact, the National Oceanic and Atmospheric Administration ("NOAA") uses a 30 year period to define normal weather, a longer time period than the one proposed by FPL.

**Q. Would the use of a 10 year average to calculate normal weather consistently result in a higher sales forecast, and therefore a reduced revenue deficiency?**

A. No. Exhibit RM-3 shows how the calculation of the rolling 20 year average and 10 year average for cooling degree hours varies over time. The 20 year average shown for the year 2011 is the same 20 year average used in FPL's load forecast in this pending case. The 10 year average shown for the year

2011 is the same 10 year average SFHHA witness Baron proposed in his testimony. As the exhibit shows, the 10 year average for the year 2011 is significantly higher than the 20 year average for the year 2011. However, this is not always the case. In fact, as recently as 2010 the 10 year average was lower than the 20 year average. The fact that the most recent 10 year average has more cooling degree hours than the most recent 20 year average is due largely to the hotter than normal weather in 2011. In many years, the 10 year average actually has fewer cooling degree hours than the 20 year average. In fact, in 7 out of the last 12 years, the 10 year average of cooling degree hours is lower than the 20 year average and would have resulted in a lower sales forecast.

Q. **Does Exhibit RM-3 suggest that the 10 year average is an appropriate period to calculate normal weather conditions?**

A. No. Exhibit RM-3 shows that the use of a 10 year average creates excessive volatility in how normal weather conditions would be defined. The annual changes in the 10 year average, on an absolute basis, are twice as large as the annual changes in the 20 year average.

Q. **Has the Commission accepted the use of a 20 year horizon to calculate normal weather conditions in past rate proceedings?**

A. Yes. The load forecasts approved in recent cases for both Gulf Power and TECO were based on 20 years of weather data to define normal weather conditions.

**Q. Has the Commission ever approved a 10 year horizon to determine normal weather conditions in any past proceeding involving an electric utility?**

A. To my knowledge, no.

**Q. Is FPL's long-term generation plan designed to reliably serve future loads based on a 10 year definition of normal weather?**

A. No. FPL's long-term generation plan is designed to reliably serve future loads based on a 20 year definition of normal weather. This is the same definition of normal weather used in the filing in this proceeding.

**Q. Is any electric utility in Peninsular Florida basing its load forecast on only 10 years of weather data?**

A. No. Based on information from the Florida Reliability Coordinating Council the electric utilities in Peninsular Florida are all using either a 20 year, 30 year or longer period of time in defining normal weather. No one uses a 10 year period.

**Q. How have cooling degree hours varied in recent years?**

A. The years 2009 through 2011 were hotter than normal, however, the immediately preceding years were characterized by milder than normal weather conditions. Exhibit RM-4 shows the annual cooling degree hours since 1992. As the chart shows, the hottest year in the last 20 years was actually 1998.

**Q. Overall, what have weather conditions been in 2012?**

A. Based on data through June, the weather in 2012 has been milder than in 2011 and close to the 20 year normals.

**Q. Does this conclude your testimony?**

A. Yes.

BY MR. RUBIN:

Q Are you also sponsoring any exhibits to your rebuttal testimony?

A Yes, I am.

Q And do those exhibits consist of Exhibits RM-3 and RM-4, also shown as Exhibits 394 and 395 on Staff's exhibit list?

A Yes.

Q Have you prepared a summary of your rebuttal testimony?

A Yes, I have.

Q Would you please provide that summary to the Commission at this time?

A Yes. Good afternoon, Commissioners. The purpose of my rebuttal testimony is to refute South Florida Hospital and Healthcare Association witness Baron's proposed use of only ten years of data as the basis for his calculation of normal weather conditions for the purpose of forecasting electric sales.

Witness Baron proposes to inappropriately limit the data used in calculating normal weather conditions rather than relying on a multi-decade horizon that has traditionally been approved in Florida. FPL, like all others electric utilities in Florida, relies on the assumption of normal weather conditions in developing its load forecast.

Normal weather conditions are defined as the weather conditions which have been experienced on average over a multi-decade period. Accordingly, FPL and the other major Florida electric utilities use a 20-year period to define normal weather conditions.

The use of 20 years to define normal weather conditions has the advantage of incorporating the most recent weather data available, while also including a sufficiently long period of time so that the results are not skewed by one or two non-representative years.

In what appears to be an effort to artificially inflate the sales forecast, witness Baron proposes to instead define normal weather conditions using only the past ten years.

My testimony demonstrates that a ten-year time period, as proposed by witness Baron, is an unreasonably short period of time to use in the calculation of normal weather conditions. Using only ten years of data would result in a volatile and unreliable definition of normal weather conditions.

This is illustrated by the chart behind me, which shows how the 20-year and ten-year definitions of normal weather conditions compare historically. The red line shows a rolling 20-year average of cool degree hours, while the blue line shows a rolling ten-year average of the same series. The blue line is clearly much more volatile than the red line.

For the year 2011, the ten-year average is much higher than the 20-year average, but in other years, the opposite is true. Mr. Baron, however, would define normal weather based exclusively on that last spiking point on the blue line.

Limiting the calculation of normal weather conditions to only ten years of data is also inconsistent with FPL's long-term generation planning, and with the load forecast approved for any other major electric utility in Florida.

Indeed, the Florida Public Service Commission has consistently relied on a multi-decade period to calculate normal weather for electric utilities in Florida. Mr. Barons proposal would represent an abrupt and potentially far-reaching break with this Commission's past practice. This concludes my summary.

MR. RUBIN: Thank you, Dr. Morley. Madam Chair, FPL tenders Dr. Morley for cross examination.

COMMISSIONER BROWN: Thank you. And Mr. Young, I think we start with Florida Power & Light?

MR. YOUNG: No, ma'am, we start with South Florida Hospital, then move down to FIPUG -- I mean, excuse me, we start with FIPUG, then South Florida Hospital --

COMMISSIONER BROWN: That's what I meant.

MR. YOUNG: -- then FEA, then we go to OPC, FRF, Mr. Saporito, and Mr. Hendricks.

COMMISSIONER BROWN: Thank you. All right, South Florida Hospital? FIPUG. I just ignored him completely.

MR. MOYLE: Thank you. Thank you, Madam Chair.

CROSS EXAMINATION

BY MR. MOYLE:

Q Good afternoon, Dr. Morley.

A Good afternoon.

Q And just to briefly review your educational training, you focused on economics in school, isn't that correct?

A That's correct.

Q Okay. And you're not -- you're not before this Commission professing expertise in statistics today, are you?

A I think that depends on what -- what the issue is. I certainly have had statistics in school, quite a few courses.

Q But in your professional career, isn't it true you've focused on forecasting in a variety of respects, and you really haven't been professionally engaged in doing statistics, per se, as part of your core business, isn't that correct?

A No, I --

Q Can you give me a yes or no or --

A I will do that. Thank you. No, I don't think I can agree with that. Since our models are econometric models, they're certainly statistically based.

Q Okay. So with respect to the testimony, your rebuttal testimony, did you consult with any statisticians in preparing your testimony?

A No, I did not. I didn't deem it necessary.

Q So I guess we're going to talk about the weather in a little detail today. And if I read your rebuttal, you're taking issue with respect to a period of measurement of ten years, is that fair, of weather data?

A Yes, using ten years to calculate normal weather conditions as opposed to 20.

Q And FPL uses -- uses weather in a couple of different respects in its business operations, isn't that correct? I mean, you use it for planning purposes and forecasting?

A We use it in the load forecasts, we use the 20-year normal.

Q Okay. And isn't it also used in the context of making adjustments to revenues that come in? The term weather adjusted, do you know what that means?

MR. RUBIN: Madam Chair, I object at this point.

Just to be very clear, Dr. Morley, the purpose of her rebuttal testimony -- and I'm reading from page three of her prefiled testimony -- is to refute South Florida Hospital and Healthcare Association witness Baron's proposed use of only ten years as the basis of his calculation of normal weather conditions for the purpose of forecasting electric sales. That was it.

This witness was here on direct examination. She was questioned, in fact, appropriately by Staff counsel regarding weather impacts on the load forecast, in general. She is here for a very limited purpose on rebuttal, and I would suggest that that question goes well beyond that limitation.

COMMISSIONER BROWN: Mr. Moyle, I'D tend to agree.

MR. MOYLE: Okay. I mean, she's asked in her rebuttal what's the definition of normal weather. There's a lot of questions about normal weather. I'll move on. I think there's already information --

COMMISSIONER BROWN: That was in her direct. I agree. Please move on.

BY MR. MOYLE:

Q What's normal weather?

A Normal wealth is defined as the 20-year average of all weather variables.

Q And so you just take 20 years worth of data, add it all up, and divide by 20 to come up with an average, is that right?

A Yes, basically. And that's one of the advantages of the 20-year average. We're not throwing in years, throwing out years, making judgments about what years should be in or out. It's a very straightforward process in that sense.

Q So what is the purpose with respect to trying to ascertain normal weather?

A The purpose of ascertaining normal weather is to include the assumption of normal weather in our load forecast in order to be consistent with the Commission's direction that electric rates in a rate proceeding be based on the assumption of normal weather conditions and also to be consistent with our long-term generation planning, which is also based on normal weather conditions.

Q So if something is not normal weather you use the term extreme weather, is that right?

A No, I don't think it's an either/or that way. I think extreme weather has a different definition. Normal weather, as I said, the 20-year average, there's a weather impact in every year, positive and negative. And the extreme weather term is used to describe a year in which the weather impact is extremely positive. And as we use the term extreme based on how the -- either the heating degree days or the cooling degrees days in that year compare historically; are they in the upper one or two percentile of any year we've experienced historically.

Q So in responding to my question you used the term extreme weather. Is it fair that if something is not classified as normal, then it's either abnormal or extreme?

MR. RUBIN: Objection, asked and answered.

COMMISSIONER BROWN: I was going to say it before you did. It's been asked and answered.

BY MR. MOYLE:

Q So how do you determine extreme weather? Is there a metric that you can apply to say, you know, well, if you take 20 years worth of data and you add it all up and it averages 100, and then if you have a measurement that is 120 with a 20 percent variability, do you have a metrics that would say to you, boy, it's a 20 percent variable, that is not normal weather?

A No, that's not the way we define extreme weather. We would define extreme weather, let's say, in the case of heating degree days, by looking at, for example, in the case of 2010, how many heating degree days did we have in that year versus all prior years. In the case of 2010, it was more than any year going back 60 years or more. So that's why we used the word extreme in describing the year 2010.

Q So with respect to making a determination about whether something is extreme, I mean, you would agree that ultimately it's a judgment that is made?

A No, I don't think I can agree with that. I think that anyone would -- most people would agree if something is at the extreme end of what has been experienced historically, that it is extreme.

Q Okay. Do you recall me asking you that question in your deposition and you giving me a different answer?

MR. RUBIN: Let me just object to that attempted form of impeachment. If Mr. Moyle wants to read the question and answer and allow the witness to take a look at the question and answer, that would be appropriate, but the way he attempted to impeach her simply is not.

COMMISSIONER BROWN: Mr. Moyle, I'll give you an opportunity to read the question and have her look at it.

MR. MOYLE: Sure. I'll read it and then ask her if she recalls that. I'm happy to show it to her, if she doesn't.

COMMISSIONER BROWN: Excuse me. Dr. Morley, do you have a copy of it?

THE WITNESS: I do not.

MR. MOYLE: I have an excerpted copy that doesn't line up to the deposition. How about if I read it and show it to her? Would that be acceptable?

MR. RUBIN: Could you tell me the page and line that you're reading from?

MR. MOYLE: On my excerpted version, it's page 32, but I don't think that matches up with yours.

MR. RUBIN: No, it does not.

MR. MOYLE: Would it be okay if I read it and then showed it to her? Or she can read it. I can just show it to her and have her read it. How is that?

COMMISSIONER BROWN: That's acceptable.

THE WITNESS: I've read the answer.

BY MR. MOYLE:

Q Would you read it out loud?

A Okay, would you like me to read --

Q Start with the question.

A -- the question? Okay, so is there --

COMMISSIONER BROWN: Dr. Morley, can you please lower the mic? And also, can you please verify that that is, in fact, the deposition, since it's just an excerpt and nobody else here has a copy of it?

THE WITNESS: Yes. Thank you. Beginning with the question: Okay, so there is a scale based on the number of cooling degree hours that trigger as to when something is normal and when something is abnormal. Is there -- if there is a variation of more than five percent, then that becomes abnormal. But if it's within five percent, it's normal. Is there some type of approach like that? If not, can you explain to me how you make a judgment normal versus abnormal.

Answer: I think we would make that judgment, for example, for the year 2010, was an extreme weather year because the number of heating degree days was higher than any year we have, based on data going back to the 1940s. So that was -- that's why we used the word extreme to describe 2010.

So the question was not how do you make the judgment out of normal versus abnormal. And I think I gave the same explanation of why 2010 was an extreme weather year that I just gave today in front of this Commission.

COMMISSIONER BROWN: Dr. Morley -- and Mr. Moyle, hold on one second. I just want to make sure that that is an accurate depiction of your deposition, since, again, we do not have a copy of it and we cannot verify that that is -- it's just an excerpt.

MR. RUBIN: Madam Chairman, I can verify that what was just read is out of the original deposition.

COMMISSIONER BROWN: Are you verifying it?

MR. RUBIN: Yes, I am.

COMMISSIONER BROWN: Okay, proceed.

MR. MOYLE: And, I mean, there's nothing nefarious going on. The excerpts are not as expensive as the big, fat deposition, so I save my clients a few dollars.

COMMISSIONER BROWN: I understand. It's just fairness.

BY MR. MOYLE:

Q So, Dr. Morley -- and I'm not sure I ever envisioned weather being this complicated. But with respect to making a determination about something not being normal weather but being extreme weather, it's your testimony that there's not, you know, a metrics or a model that you use to make that determination, is that correct?

A No, I don't think that's true. I think there's two different metrics that we have. One is the calculation of the weather impact by year, and that is based on the weather variables for that year versus the 20-year normal. And that process is the same regardless of whether it's a very hot year, a very cold year; the calculation of the weather impact is the same.

The determination of whether a year might be called extreme or not would be based on how that year's cooling degree days -- pardon me -- cooling degree hours or heating degree days compare with all other years we have in our historical base.

Q Okay. And you would agree that with respect to measuring weather that the determination as to normal weather over time has used a different -- differing number of years, correct?

A Yes, and my understanding is in Florida it's always been based, for electric utilities, on a multi-decade approach.

Q Okay. And with respect to -- I mean, originally you all used, I think, since 1948, is that right, to measure? It was a data set that was bigger?

A That's correct.

Q And now you're using 20 years?

A That is correct. We are using the 20 years to be consistent with the other Florida utilities and to incorporate the most recent weather data available while also having a sufficiently long period of time to avoid the instability that would exist in a shorter time period.

Q On page eight of your testimony I think you say somebody is using 30 years within the Florida Reliability Coordinating Council, is that right?

A That's correct.

Q Who is using 30 years?

A I don't know specifically. I believe it is one of the -- it's not one of the IOUs, certainly not one of the major IOUs.

Q Okay. And you would agree that with respect to planning, for the purposes of information that is submitted to this Commission to reveal FPL's future power plant needs, that the planning horizon for that is ten years, correct?

A Yes --

MR. RUBIN: Let me just object, again. We are getting very far afield from the subject of this witness's rebuttal testimony.

COMMISSIONER BROWN: Sustained.

THE WITNESS: Yes, the load forecast in the Ten Year Site Plan --

MR. MOYLE: She went against me, so I have to strike that.

THE WITNESS: It's a long day.

MR. MOYLE: That's all I have. Thank you.

COMMISSIONER BROWN: Thank you. South Florida?

CROSS EXAMINATION

BY MR. WISEMAN:

Q Good afternoon, Dr. Morley.

A Good afternoon.

Q Dr. Morley, would you agree that one way of testing whether a population of data is stable or changing over time is to use a regression analysis?

A I'm not sure, no.

Q Well, let me ask you this, then. Let's go back -- it's your position in your rebuttal testimony that it's appropriate to base your net energy for load forecast in this rate case based upon the 20 years of weather data that you used as opposed to the ten years of weather data that was recommended by SFHHA witness Baron, is that correct?

A That's correct.

Q And would you agree you haven't presented in your rebuttal testimony a regression analysis or in fact any other similar type of statistical analysis to determine whether there's a warming trend affecting cooling degree hours over the last 20 years?

A No, I have not done that. I don't think it's necessary given this Commission's position on the 20-year average, and also given the clear variability in the ten-year average.

Q Well, I'm glad you referred -- let the record reflect that the witness turned and pointed to the chart that's behind her. That chart is a replica of your Exhibit RM-3, correct?

A Correct.

Q Okay. And if I understand the data that are on that chart and in your exhibit, each data point reflects as applicable the ten-year or 20-year average annual cooling degree hours at the year designated on the access -- axis, is that correct?

A Yes.

Q Okay. And looking at the data that you plotted for the 20-year average, wouldn't you agree that those data show a clear upward trend from 2002 through 2011?

A I'm not sure I agree with that because I think if you look at a different time period you'd reach a different conclusion.

Q Well, I'm asking you to look at the period that you've reflected here, 2002 through 2011. And is it your testimony that the data that you plotted there, based on your 20-year average line, that that doesn't show an upward trend?

A No, not based on what I'm showing, which is from 2000 to 2011.

Q Well, if I look at 2000 -- let's -- you see -- first of all, let's start with 2002, the question I asked. From 2002 through 2011, the data you plotted using your 20 average data, is it your testimony that that does now show an upward trend?

A No, I don't think it necessarily shows an upward trend because there are years there when it goes down, and I think if you look at a different horizon -- for example, 2008 to 2011 -- it looks very stable.

Q All right, we'll go with that.

MR. WISEMAN: If we could have marked for identification as the next exhibit in order, this is a document -- and by way of explanation, this is -- these are remarks by Lewis Hay, Chairman and Chief Executive

Officer of the FPL Group, and this document was obtained off of FPL's website.

COMMISSIONER BROWN: I have 585 for identification.

(Exhibit 585 marked for identification.)

MR. WISEMAN: Your Honor, I believe 585 was --

COMMISSIONER BROWN: No, I struck that.

MR. WISEMAN: Oh, okay.

COMMISSIONER BROWN: Any objections?

MR. RUBIN: I'm just taking a quick look at it. Thank you.

MR. MOYLE: Madam Chairman, 585 was the newspaper article.

COMMISSIONER BROWN: It didn't come in.

MR. MOYLE: Yeah, it may come in or at least try to be authenticated with another FP&L witness at some future point in time, on rebuttal so --

COMMISSIONER BROWN: Okay, you can try again.

MR. MOYLE: Okay. But should we maybe keep 585 so we can try it with the --

COMMISSIONER BROWN: No. No. You can try again with a new number.

MR. MOYLE: Okay.

MR. RUBIN: Thank you. I have no objection to this document.

COMMISSIONER BROWN: You may proceed.

MR. WISEMAN: Thank you.
BY MR. WISEMAN:
Q Dr. Morley, can you look at the third paragraph down, right under the title that says Competing Visions of the Future. Do you see that?
A Yes.
Q Okay. And would you read out loud the first line through the first word on the second line.
A The government's vision is rooted in an undeniable reality, namely, that global climate change is real.
Q Now, the global climate change that Mr. Hay was referring to is global warming, correct?
A I would assume so.
Q Pardon me?
A I would assume so.
Q And let's take a look -- let's turn to page two of the document. And if you look at the first full paragraph, the second sentence, it says there are still a few global warming skeptics left in the world, often big emitters of CO2. Do you see that sentence?
A Yes, I do.
Q Dr. Morley, you're not a global warming skeptic, are you?
A I would say that's a yes or no question, if I could answer. Yes, I certainly agree that the climate today

is probably different than it was a hundred years ago or a thousand years ago. But I would disagree that the cooling degree hours in our service territory are going up and up every year. I don't think the data show that. But is there general climate -- is the climate today different than it was a hundred years ago or so? Yes, I agree.

Q Is FPL a skeptic of global warming?

MR. RUBIN: Let me object. That calls for speculation. The witness has answered for herself.

COMMISSIONER BROWN: I agree. I agree. Rephrase it, please.

BY MR. WISEMAN:

Q Does FPL, to your knowledge, have policies that are intended to address global warming?

A I'm not aware of all the policies FPL has. I know about the load forecast.

Q All right, let's turn to page three of the document. And do you see there's a title that says FPL Leading the Way?

A I do.

Q Why don't you read -- you can just read it to yourself. Why don't you read the paragraph underneath that.

A Think of what would happen --

Q No, you can read it to yourself. You don't have to read it into the record. You can if you want to. Have you read it?

A Yes.

Q All right. Would it be fair to say that the FPL Group and now NextEra Energy, Inc., wants to lead the way in recognizing and addressing global warming?

A Yes, that's what this document says.

MR. WISEMAN: If we can next have marked the next exhibit in order -- this is a response to an interrogatory.

COMMISSIONER BROWN: That will be marked as 586 for identification.

(Exhibit 586 marked for identification.)

COMMISSIONER BROWN: Any objections?

MR. RUBIN: Once again, Madam Chairman, I don't object. It's an FPL answer to interrogatory, but the subject of this interrogatory answer was appropriately addressed or should have been appropriately addressed on direct, not on this rebuttal. It goes well beyond the scope of the rebuttal testimony.

MR. WISEMAN: If I could address that, Madam Chair.

COMMISSIONER BROWN: Yes.

MR. WISEMAN: There is a difficulty in this case, that is, FPL address multiple witnesses who address pieces of related issues. And I will agree that this particular response is beyond the scope of Dr. Morley's rebuttal testimony. However, it is directly relevant to the testimony of Mr. Ender.

Mr. Ender is going to take the stand later, and if I present this document to him, he's going to say, I don't know, I didn't sponsor it; can't help you. So I only have a limited question on this. It's actually to have Dr. Morley acknowledge that she sponsored this answer, that it's hers, and to read the answer, and then I will ask Mr. Ender questions about it.

COMMISSIONER BROWN: I'm okay with that. Do you want to respond?

MR. RUBIN: I do. Just for the record, the interrogatory, itself, begins: Regarding Morley at page 18, line 21 through page 19, line three. That is her direct testimony. There's only nine pages of rebuttal testimony. So I would renew the objection that this is something that should have been done on direct if there was an issue here.

MR. WISEMAN: Again, Madam Chair, that doesn't address my comment. I said this doesn't have to do with Dr. Morley's testimony. I am putting this in in order to cross examine Mr. Ender later on, on his rebuttal testimony. And I'll point to the specific lines when we get there.

MR. RUBIN: And I will stipulate that it's an FPL answer, and the Hospital Association can use it to question Mr. Enter. I have no quarrel with that at all. It's just not appropriate here.

COMMISSIONER BROWN: But his concern is that Mr. Ender may not be able, because there's some overlap on the issue, his concern is that Mr. Ender may not be able to testify to this. So restate what you intend to ask.

MR. WISEMAN: I only want to ask her two things. One is to -- actually, I can just ask her to stipulate, or to confirm that this is her answer that she provided. And I was going to have her read it, but I can have Mr. Ender read it. That would be fine.

COMMISSIONER BROWN: Acknowledging that this is not related to her cross -- to her rebuttal testimony, the purpose of --

MR. WISEMAN: Is simply to have her confirm that this is the answer that She provided to this interrogatory, so that when I cross examine Mr. Ender, Mr. Ender won't say, I don't know what that document is, I can't confirm it, and so I can't provide -- I can't answer the questions you're asking me. Even though the questions will be directly relevant to his rebuttal questions -- rebuttal testimony.

COMMISSIONER BROWN: I appreciate your response, but I'm going to ask Ms. Helton.

MS. HELTON: I think Mr. Rubin has said that he's okay with the witness authenticating it, or with him, himself, actually authenticating the document so that it will be available or will be properly authenticated for Mr. Wiseman to ask a question of Mr. Ender. Is that correct?

MR. RUBIN: I think that's correct. I just object to substantive questions on it. But as far as her authenticating it, absolutely, I have no problem with that.

MR. WISEMAN: That's fine then. I think we're good and I can move on. Well, let me -- actually, one thing Mr. Rubin just said threw me for a loop. So may I address Mr. Rubin directly?

My only question is, so if I use this document with Mr. Ender, that there won't be a question of authentication. Mr. Ender will -- and FPL will stipulate that this is Dr. Morley's answer in this case.

MR. RUBIN: I agree. I so stipulate for FPL.

COMMISSIONER BROWN: That was confusing.

MR. WISEMAN: All right. Then we can -- we can -- first, this has already been marked. Are we going to leave it at 586?

COMMISSIONER BROWN: Yes.

MR. WISEMAN: Then if we can have another document marked for identification.

COMMISSIONER BROWN: Which will be 587.

(Exhibit 587 marked for identification.)

MR. WISEMAN: Let me represent that this document reflects -- it's the first two pages are a compilation of data taken from the FPL website. The data are provided in the back-up pages in the exhibit. And if it would help FPL, if it questions where this data came from at all, we have full copies of the data -- full copies of the documents that were on FPL's website, as well

COMMISSIONER BROWN: Mr. Rubin, any objection?

MR. RUBIN: Subject to the witness's recognition of the document, I have no objections.

COMMISSIONER BROWN: Okay, you may proceed.

MR. WISEMAN: Thank you.

BY MR. WISEMAN:

Q Dr. Morley, turning to page three, and the remaining pages of this document, do you recognize these as data that FPL tracks in the regular course of business?

A Yes.

Q Okay. Now, let's turn to page one, and I'll ask you to accept, subject to check, that what we've done is we've taken the data from these pages off of -- off a Web site and transferred them onto this summary, on page one, and the summary on page two, as well.

And let me also say, by explanation, the blacked out period for 2004-2005 and a portion of 2006 is only because the data were not on the website. We couldn't locate those data.

So for the years represented here where data were available, would you agree that it shows that in every year the actual cooling degree hours exceeded normal cooling degree hours?

A If you give me a moment, please.

Q Sure.

A Yes, and you're missing the three years where they were below normal.

Q Well, so you're saying that FPL doesn't publish data on its website where the years are below normal?

MR. RUBIN: Objection, that's not at all what she testified to.

MR. WISEMAN: Madam Chair, what she's suggesting is that we purposely deleted data, and that's not the case. We took the data that was available on the website. I don't know what those data say, and I think, actually, her answer should be stricken, because there's no factual basis for it.

The data is not on the website. If they can produce it, that's fine, but it's not on the website.

MR. RUBIN: Madam Chair, first of all, Dr. Morley didn't suggest anything about anyone removing date or doing anything untoward. She simply answered the question and indicated that there was three years of data that are missing here, and then she indicated what they were.

In counsel wanted to obtain that information through discovery, they should have requested it. Perhaps they did request it. But this is not the time to be doing discovery.

COMMISSIONER BROWN: I'm going to allow the objection -- sustain the objection.

MR. WISEMAN: But I'm not sure what --

COMMISSIONER BROWN: Please proceed with your questions. Move along.

MR. WISEMAN: Okay, thank you.

BY MR. WISEMAN:

Q So my question -- and I think you agreed -- I just want to explore, so the record is clear. You agree that the data reflected on page one of Exhibit 587 demonstrates that in every year for which data were available on FPL's website that actual cooling degree hours exceeded normal cooling degree hours, correct?

A Yes, and, of course, there's no data there for

2006, five or four.

Q Fair enough. Now let's move to the second page of the document. And you see that up at the third -- at the top of the page that this document reflects cooling degree hours during the third quarter, correct?

A Correct.

Q Okay. And could you, you know, take your time and check. Would you agree that page two shows that in every third quarter of every year for which data were available on FPL's website, that actual cooling degree hours exceeded normal cooling degree hours?

A Yes, for that specific quarter and for those four years available.

MR. WISEMAN: Thank you. Madam Chair, I have no further questions. Thank you, Dr. Morley.

COMMISSIONER BROWN: Okay. FEA?

CAPT. MILLER: No questions. Thank you.

COMMISSIONER BROWN: Office of Public Counsel?

MS. CHRISTENSEN: No questions.

COMMISSIONER BROWN: Retail Federation?

MR. WRIGHT: Thank you, Madam Chair.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Dr. Morley.

A Good afternoon.

Q You've criticized Mr. Baron's use of a ten-year average of cooling degree hours as opposed to your proposed 20-year average, correct?
A That's correct.
Q Your 20-year average implies lower sales and revenues, and Mr. Baron's ten-year average implies greater sales and revenues, correct?
A That's correct.
Q Other things equal, lower sales will indicate, in the test year, will indicate a greater need for rate relief, correct?
A I think there's probably a lot of moving parts with costs. I'm not sure I could agree with that.
Q Other things equal, isn't it true that lower sales in a test year will indicate a greater need for rate relief?
A I would agree that lower sales would mean lower revenues at present rates.
Q And then holding other things equal, that would imply a greater need from rate relief from present rates to the test year, correct?
A I think -- again, I think that depends on a number of things. I would agree it would reduce revenues at current rates.
Q Are you not able to answer the question subject to the specific qualification that I stated: Other things being

equal?

A No, I'm not able. I would agree it would affect the revenue level of present rates.

Q Should the Public Service Commission use the best estimates of load and sales for any test year?

A I'm sorry, I missed a word in there. Could you repeat? Sorry.

Q Certainly. Should the Public Service Commission use the best estimates for a utility's projected load and sales in setting rates for any given test year?

A Not in terms of weather. I think they should use an assumption of normal weather and specifically the 20-year normal.

Q If there were data that tended to indicate that usage in the test year would be greater than indicated by a 20-year average, shouldn't the Public Service Commission consider that?

A Just because it affects usage? No. I think there would have to be a better reason to consider it than the fact it would just affect usage.

Q Well, you do a load forecast for the purpose of -- basically as a starting point for establishing billing determinants, correct?

A Yes.

Q Okay. Your load forecast is based on what you characterize as normal weather, correct?

A That's correct.

Q If -- my question, then, is this: If there were better information -- if there were information evidence available to indicate that load in the test year would be greater than indicated by a normal weather projection, shouldn't Florida Power & Light use that?

A No. I believe the Commission orders state that the load forecast in a rate proceeding should be based on normal weather assumptions.

Q So it's your testimony that if there's better evidence available the Commission and FPL should just ignore that because of a prior order?

MR. RUBIN: Let me just object. It's been asked and answered, I think, four times now.

COMMISSIONER BROWN: It's been asked a few times.

MR. WRIGHT: I'm just trying to get clarity. I'm shocked at her answer, frankly.

COMMISSIONER BROWN: You've asked it three times.

MR. WRIGHT: I shall move on. Thank you.

BY MR. WRIGHT:

Q Do I understand your Exhibit RM-3 to represent -- do I understand each point on your Exhibit RM-3 to represent the 20-year normal weather value for the year calculated using 20 years of data ending in the year shown on what I call the X axis, the horizontal axis?

A Yes, it's ended in July of the year shown.

Q Okay. So if I understand that answer, is it correct that the value shown there for the year 2000, which -- sorry -- it appears to be something like 1,915 cooling degree hours? Well, let me ask you that question.

Is it correct that the value shown for the year 2000 corresponds to a value of approximately 1,915 cooling degree hours on the vertical axis?

A Yes.

Q And that value is the average value for all 20 years, ending in July of 2000, so that would be the period July, 1981 to July of 2000, correct?

A Correct.

Q And similarly, say, for 2002, it looks like the value is something like 1900 or maybe a hair over that, is that accurate?

A Yes.

Q And that's a value for the 20 years ending in July of 2002, correct?

A Correct.

Q And similarly, if we move on out to the right-hand end of the X axis, the value for 2011. The 20-year value, is 1,960 hours, correct?

A Approximately, yes.

Q Recognizing that starting with the 20-year period ending in 2000, with the value of 1915, and then moving forward to a new 20-year value in 2011 of 1960 cooling degree hours, wouldn't be agree that your 20-year average data indicate an upward trend in consumption? In cooling degree hours. Sorry.

A Yes, I would agree that the 20-year average ending in 2011 is higher than the 20-year average ending in the year 2000.

Q And I could walk you through every year on the table, but other than the decline from 2000 to 2002, they pretty much slope upwards from 2002 through 2011, don't they?

A No, I believe in 2007 and 2009 they -- there is a decline.

Q Overall, the averages, the 20-year averages from 2002 to 2011 are upward sloping, correct?

A Based on that particular time period. But if we looked at a different time period, I don't think you would draw that conclusion.

Q That's really 12 different -- this data represents 12 different 20-year time periods, does it not?

A That's correct.

Q I'd like to ask you to look, if you would, please, at your Exhibit RM-4. Do I understand correctly that these are the company's reported annual cooling degree hours per year for the 20 years shown?

A That's correct.

Q So, for example, the value -- in 1992 FPL recorded or your data indicate that you had approximately 1,850 cooling degree hours, correct?

A That's correct.

Q And in 2008 you had approximately, say, 1,950 or so?

A Correct.

Q And in 2011 you had approximately 2,160 or so?

A That's correct.

Q Okay. Are you familiar with any information regarding warming trends, how many of the last ten or 11 years have been among the warmest ever recorded?

A Generally I'm sure the last -- certainly 2011 and 2009 were among the warmest.

Q I will aver to you that I've read that among the hottest years on record are 2002, three, seven, nine, ten and 11. Is that consistent with your understanding?

A Could you repeat those years? Sorry.

Q 2002, 2003, 2007, 2009, 2010 and 2011.

A And when you say among -- which time period are you referring to?

Q Recorded history.

A And I'm sorry, what's your question?

Q My question is, will you agree that the years 2002, three, seven, nine, ten and 11 are among the warmest years in recorded weather history?
A No, I'm not sure I could agree with that relative to the FPL service territory because 2007 does not appear to be a particularly high year in terms of cooling degree hours.
Q If you could please continue looking at your Exhibit RM-4. What I want to do is ask you to focus on years within the last ten years that were above average and years that were below average. To me it appears -- and if you'd like I could give you a ruler and you could lay it on the table where there's 1,800 -- 1,960 hours.
A That won't be necessary.
Q It looks to me like 2008 is right about smack on the average. Do you agree with that? Maybe slightly below?
A No, it was below average.
Q It was about 1950?
A About, yeah. It was below average.
Q And the average is 1960. Okay. So slide your ruler up just above that little square there, the 2008 square. Surely you'll agree that six out of the ten years -- six out of the last ten years were above average, 2002 through 2011?
A Six out of ten?
Q Six out of ten, where the first year of the ten is

2002 and the last is 2011.

A Yes, I would agree with that, and then four out of ten would be below normal.

Q One was real close, '08 was real close, was it not?

A It was below normal; '08 was below normal, 2006 was below normal, 2005 was below normal, 2004 was below normal.

Q Okay. On page six of your testimony you express concern in two separate places that a ten-year average could skew the results of an analysis. I'm sure you recall that testimony.

A Yes.

Q Okay. Given that six out of the ten years have reflected cooling degree hours for Florida Power & Light that have been greater than the 20-year average, you'd agree that that concern is not applicable to this ten years worth of data, would you not?

A No, I would not agree with that. I would agree, you know, 2011 was 10 percent above normal, and I think that would qualify as a non-representative year that's skewing the results. And I think that's evident if you'd compare the ten-year average for the year ending 2011 with the 20-year average.

Q I think this has been asked and answered, but

I just want to make sure. You did not do any statistical analysis, or like a time regress or anything like that, to estimate a trend line over your 20-year period, did you?

A No, I'm not trying to project weather, I'm using the 20-year normal as prescribed by this Commission.

Q Is it prescribed in a rule?

A No, but it's consistent with the load forecast approved in the most recent rate proceeding for all the other major IOUs.

Q When I look at your Exhibit RM-4, if you could keep your ruler there, I observe that four out of the first six years are below the average for the period. Do you agree with that? That would be '92, '93, '96 and '97.

A That's correct.

Q And you previously agreed that six out of the last ten are above average, correct?

A That's correct.

Q And in fact four out of the last five are above average; also correct?

A That's correct.

Q Okay. Looking at this data, wouldn't you agree that the overall trend is upward sloping?

A No, I would not, because I think it depends on the time period you're looking at.

Q Well, the time period is 20 years, Dr. Morley.

Given the 20-year time period that you espouse, don't you agree that the overall trend is upward sloping?

MR. RUBIN: Let me object. It's been asked and answered. She's qualified her answer with this time frame and actually it's been asked and answered many times.

MR. WRIGHT: Madam Chairman, she did not answer my question. She said it depends upon what time period you're looking at. I tried to bring her back to the 20-year time period.

COMMISSIONER BROWN: And I think that's because it's not a yes or no. She wants you to clarify. You have asked it twice. Can you restate it in a different way so that she can understand your question more clearly?

MR. WRIGHT: Of course.

COMMISSIONER BROWN: Thank you.

BY MR. WRIGHT:

Q Dr. Morley, recognizing that four out of the first five years of the 20-year period were below the average -- sorry, four out of the six years, first years, of the time period were below the 20-year average, and also recognizing, as you recently acknowledged, that four out of five of the latest years in the same 20-year time period were above average, will you not agree that the trend over this 20-year time period is upward sloping?

A Yes, I would agree that the 20-year average ending 2011 is higher than the 20-year average ending in the year 2000.

Q We were speaking, I believe, of your Exhibit RM-4. That's not 20 year averages, is it?

A I apologize. No, I -- looking at RM-4, I don't see a clear upward trend. I see a lot of movement up and down. I don't see a clear trend one way or the other.

MR. WRIGHT: I have an exhibit, Madam Chair.

COMMISSIONER BROWN: That will be 587 for identification purposes.

COMMISSIONER BROWN: Staff, is it 587?

MR. HARRIS: 588.

COMMISSIONER BROWN: 588. That's right.

(Exhibit 588 marked for identification.)

(Transcript continues in sequence in Volume 23.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA )
COUNTY OF LEON )

I, LAURA MOUNTAIN, Court Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing proceedings; and that the transcript is a true record of the aforesaid 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' attorney or counsel connected with the action, nor am I financially interested in the action.

Dated this 31st day of August, 2012.

Laura Mountain

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