BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140025-EI

APPLICATION FOR RATE
INCREASE BY FLORIDA
PUBLIC UTILITIES COMPANY.
_________________________/

VOLUME 3
Pages 484 through 654

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: COMMISSIONER LISA POLAK EDGAR
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

TIME: Commenced at 1:03 p.m.
Concluded at 1:45 p.m.

DATE: Monday, September 15, 2014

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

NAME:	PAGE NO.
JEFFERY A. SMALL	
Prefiled Direct Testimony Inserted	488
JEFFRY M. HOUSEHOLDER	
Prefiled Rebuttal Testimony Inserted	494
CHERYL M. MARTIN	
Prefiled Rebuttal Testimony Inserted	514
JIM MOSS	
Prefiled Rebuttal Testimony Inserted	547
MATTHEW M. KIM	
Prefiled Rebuttal Testimony Inserted	560
P. MARK CUTSHAW	
Prefiled Rebuttal Testimony Inserted	600
ALEIDA SOCARRAS	
Prefiled Rebuttal Testimony Inserted	609
PAUL MOUL	
Prefiled Rebuttal Testimony Inserted	617

EXHIBITS

NUMBER:	ID.	ADMTD.

No exhibits marked or admitted in this volume

(Transcript follows in sequence from Volume 2.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF JEFFERY A. SMALL

DOCKET NO. 140025-EI

JULY 28, 2014

Q. Please state your name and business address.

A. My name is Jeffery A. Small 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 (FPSC or Commission) as a Regulatory Analyst 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 Commission since January 1994.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Science degree in Accounting from the University of South Florida. I am also a Certified Public Accountant licensed in the State of Florida.

Q. Please describe your current responsibilities.

A. Currently, I am a Regulatory Analyst 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 expert testimony before this Commission or any other regulatory agency?

A. Yes. I have provided testimony in the Duke Energy Florida, Inc., Nuclear Cost Recovery Clause filings, Docket Nos. 080009-EI, 090009-EI, 100009-EI, 110009-EI, 120009-

EI, 130009-EI and 140009-EI. I have also testified in the Southern States Utilities, Inc. rate case, Docket No. 950495-WS, the transfer application of Cypress Lakes Utilities, Inc., Docket No. 971220-WS, and the Utilities, Inc. of Florida rate case, Docket No. 020071-WS.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Public Utilities Company (FPUC or Utility). The audit report is filed with my testimony and is identified as Exhibit JAS-1.

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

A. Yes.

Q. Please describe the work you performed in both audits.

A. The audit report addresses the Rate Base, Capital Structure and Net Operating Income components as of September 30, 2013, for FPUC:

<u>Rate Base</u>

- We verified, based on a sample of plant in service (PIS) additions, retirements and adjustments for selected plant accounts, that the Utility's PIS is properly recorded for the period January 1, 2007 through September 30, 2013. We recalculated a sample of 13-month average balances for PIS included in the filing.
- We verified, based on inquires and examination of rate base asset accounts, that the Utility's general ledger does not reflect a Plant Held for Future Use balance.
- We verified, based on a sample of construction work in progress (CWIP) projects included in the filing, that the CWIP balance is properly stated as of September 30, 2013. We reviewed Utility documents describing each project sampled to determine whether it was eligible to accrue allowance for funds used during construction (AFUDC). No projects sampled accrued AFUDC. We recalculated a sample of 13-month average balances for CWIP included in the filing.

- We verified, based on a sample of selected accumulated depreciation (AD) accounts, that the AD is properly recorded for the period January 1, 2007 through September 30, 2013, and that the Utility used the depreciation rates approved in Commission orders. We recalculated a sample of 13-month average balances for selected AD accounts included in the filing.
- We verified, based on a sample of selected accounts, that the working capital (WC) balance is properly stated, utility in nature, non-interest bearing and is consistent with Commission orders. We verified, based on a sample of selected accounts, that the accumulated provision accounts year-end balances comply with Commission rules. We recalculated a sample of 13-month average balances for selected WC accounts included in the filing.

Capital Structure

- We traced the equity account balances to the general ledger. We recalculated the 13-month average balance for equity included in the filing.
- We reconciled the long term debt (LTD) balance to the general ledger. We traced the LTD obligations and the unamortized loss on reacquired debt balance to the original documents and verified the terms, conditions, redemption provisions and interest rates for each bond or note payable. We sampled and verified the cost of LTD. We recalculated the average cost rate and the 13-month average balance for LTD included in the filing.
- We reconciled the short term debt (STD) balance to the general ledger. We traced the STD obligations to the supporting documents. We verified the average cost of STD. We recalculated the average cost rate and the 13-month average balance for STD included in the filing.
- We reconciled the customer deposit (CD) balance to the general ledger. We inquired

and verified that the Utility is collecting, refunding and paying interest on CD pursuant to Rule 25-6.097, Florida Administrative Code (F.A.C.). We recalculated the average cost rate and the 13-month average balance for CD included in the filing.

- We reconciled the accumulated deferred income tax (ADIT) balances to the general ledger. We recalculated the 13-month average balance for ADIT included in the filing.
- We reconciled the investment tax credit (ITC) balances to the general ledger. We recalculated the average cost rate and the 13-month average balance for ITC included in the filing.

Net Operating Income

- We reconciled revenues to the general ledger. We reviewed Commission audits of the Utility's cost recovery clauses, which included recalculations of a sample of customer bills, to ensure that the utility was using the base rates authorized in its approved tariff. We verified that unbilled revenues were calculated correctly.
- We verified, based on a sample of utility transactions for select operation and maintenance (O&M) expense accounts, that O&M expense balances are adequately supported by source documentation, utility in nature and do not include non-utility items and are recorded consistent with the Uniform System of Accounts (USOA). We reviewed samples of utility advertising expenses, legal fees, outside service expenses, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed. We reviewed a sample of intercompany allocations and charges to determine if expenses were allocated pursuant to Rule 25-6.1351, F.A.C.
- We recalculated a sample of depreciation expense accruals for 2011 and the test year to verify that the utility is using the correct depreciation rates.
- We verified that taxes other then income expenses are adequately supported by source

documentation.

- We traced federal and state income taxes to the general ledger. We reviewed bonus depreciation treatment for asset additions. We verified that adjustments to income tax expense are consistent with the USOA.

<u>Other</u>

- We developed a three-year (2010 -2012) analytical review that compared the annual percentage change for the FERC account balances. Accounts that exhibited significant activity or percentage change, as determined by the auditor, were randomly selected for additional review.
- We reviewed the 2010-2013 FERC independent audit reports for FPUC, issued on August 12, 2011, July 30, 2012 and June 20, 2013, respectively. We reviewed selected correspondences and communications between the Chesapeake Utility Company(CUC)/FPUC Audit Committee and its external auditors for the above audit engagements.
- We reviewed the respective Board of Directors meeting minutes for FPUC and CUC through June 2014, for activities or issues that could affect FPUC in the instant proceeding.

Q. Were there any audit findings in the audit report, JAS-1.

A. Yes.

Q. Please review the audit findings in the audit report, JAS-1.

A. **<u>Audit Finding No. 1</u>**

Provides information that corrects the Utility's adjustments to Rate Base and Net Operating Income for non-regulated operations. This adjustment was needed because the Utility's adjustment in the filing was not supported by adequate documentation. Our subsequent correcting adjustment, which was provided by the Utility and verified by audit staff, increased average Rate Base by $9,053, increased Depreciation Expense by $389, and reduced Income Tax Expense by $150.

Audit Finding No. 2

Provides information that corrects the Utility's adjustment to Rate Base and Net Operating Income. This adjustment was needed because the Utility used incorrect rates when calculating depreciation accruals for two transportation plant-in-service accounts. However, audit staff's recalculation of depreciation accruals for the two transportation plant-in-service accounts using Commission authorized rates and supplemental information provided by the Utility during the audit showed that an additional adjustment was needed. Our correcting adjustment increased average Rate Base by $33,831, increased Depreciation Expense by $17,401, and reduced Income Tax Expense by $6,713.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name, affiliation, business address.

A. My name is Jeffry M. Householder. I am the President of Florida Public Utilities Company ("FPU" or "the Company"). My business address is 911 South 8th Street, Fernandina Beach, Florida 32034.

Q. Are you the same Jeffry M. Householder who filed direct testimony in this proceeding?

A. Yes.

Q. Please state the purpose of your rebuttal testimony.

A. The purpose of my testimony is to comment on the direct testimony of witnesses Ramas and Woolridge filed on behalf of the Office of Public Counsel ("OPC") in this proceeding.

Q. Please summarize the key issues and areas that you will address in your rebuttal testimony.

A. My rebuttal testimony will focus on the substantive negative impact to the Company, its ratepayers and shareholders that would occur if the OPC base or alternative rate recommendations were adopted by the Commission. I will comment on the Company's efforts to hold costs down, while at the same time expanding its capabilities to provide better service to customers, negotiate more favorable wholesale power agreements, and increase system operational reliability. I will comment on the benefit to ratepayers associated with the Company's incentive pay plans for management and other employees. Finally, I will touch on the risks inherent in operating a small non-generating electric utility and the unreasonableness of the OPC ROE recommendation in that regard. Other Company rebuttal witnesses will address these topics in greater detail. However, I believe that it is important for me, as President of the Company, to summarize the grave concern we have with many of OPC's positions.

Q. What was your reaction to OPC's direct testimony recommendation that FPU's base rate increase be limited to $1,996,096?

A. I was astounded and disappointed that OPC would find such a low overall increase to be appropriate. The proposed OPC rate increase would negatively impact service capabilities and system reliability as well as deny the Company the ability to earn a fair and reasonable return on its electric system investments. This recommendation is inconsistent with sound regulatory policy. An award at the proposed OPC level would virtually assure that the Company would experience subpar returns and be forced to file for relief again soon after the conclusion of this case. That is <u>not</u> in the best interests of our customers.

Upon reviewing OPC's specific recommendations, I was somewhat encouraged that there were at least some areas of apparent agreement. With the exception of other revenue late fees, there were no proposed OPC adjustments to the Company's revenue forecast. As other rebuttal witnesses will describe, the Company takes issue with several of OPC's rate base adjustments; however, the significant system replacement and reliability improvement investments made by the Company since its last case were appropriately included.

Unfortunately, OPC fails to recognize the value to customers of the expanded corporate services provided by Chesapeake ("CUC"). They cavalierly dismiss the customer benefits resulting from the adoption of modern employee compensation plans that include both operational and financial performance incentives. Finally, OPC's proposed ROE level of 9.0% is not only technically unsupportable, but also would, without a doubt, affect the Company's ability to attract capital at reasonable rates. Again, that is <u>not</u> in the best interest of our customers.

Q. Please provide an overview of the Company's current operating and financial situation.

A. As described in my direct testimony, it has been seven years since the Company's last rate case. During that time the Company's marginal revenues have not grown. As is the case with most U.S. electric utilities, revenues have been generally flat or declining over the past decade. The recent "Great Recession" further eroded revenues as new construction growth stopped and as customers increased conservation efforts. In spite of our efforts to control costs, expenses for maintenance, personnel, gasoline, and health benefits, have continued to increase.

Regardless of the upward pressure on costs and declining or stagnant demand, the Company takes its obligation to provide quality service extremely seriously. We operate reliably, assuring customers of quality service. The Company did not cut corners in its efforts to operate reliably. Equipment and facility maintenance was increased. Significant investments were made to improve, replace and upgrade substation, transmission and distribution facilities. Our system reliability and customer survey results speak to the success of these investments. In addition, we have been attentive to improving customer service, metering, GIS mapping, storm hardening and many other operational activities.

None of these physical improvements result in sustained customer benefits without an engaged, professional workforce. Several of the cost increases OPC is recommending against are directly related to attracting and retaining qualified employees in a competitive marketplace. Other necessary expense increases are associated with expanded IT and HR services, along with increased planning and business development services. In my view, these are appropriate costs required to meet the service needs of our customers and ultimately hold down future rate increases. For instance, we are already seeing that more efficient technology has enabled greater, more efficient communication with our consumers.

The Company's commitments to physical system improvements and expenses that strengthen our service capabilities in the face of a weak economy have steadily reduced returns. **In fact, the Company has under-earned every year since the 2008 rate case.** So, while FPUC's customers have not suffered, FPUC's investors have suffered.

Year 2014 will be the sixth year that the Company will have earned below the level the Commission last determined was fair for FPUC. So, for six years, while customers have enjoyed increased reliability and benefitted from the Company continuing to add investment to serve them, the investors who have provided the equity funds necessary to improve customer reliability and service have increasingly earned lower and lower returns. All those returns are unfair under the Commission's last rate determination. This failure to achieve a return that is fair to investors cannot continue. Eventually, it will affect our ability to serve customers.

At the end of June 2014, FPU's average return on equity had dropped to 4.07%. The forecast return on equity without rate relief by the end of the projected test year is negative (-) 1.46%. If anything, the OPC recommended base rate increases would only marginally improve that result, but they would fall far short of a fair and reasonable return level. It is past time for our investors to be treated as fairly as our customers. If they are not, then they will decline to continue financing or charge us higher costs for their funds, either of which would seriously and adversely affect our customers and the service provided by the Company.

Q. Why did the Company delay filing for new rates until 2014?

A. We always strive to balance the impacts of any actions we take between ratepayers and shareholders. As our return on equity began to decline, we contemplated filing for higher rates, but we held off in part because we knew that our customers were also facing stress from a struggling economy. While we refrained from seeking an increase in base rates, our wholesale power costs began to increase in 2008, following a decade in which we had benefitted from some of the lowest power costs in the state. So, we decided not to seek base rate relief on top of the rise of wholesale power costs our customers were facing. By 2014, our total power costs were generally back in line with the regional providers in both FPU divisions, and we could not justify staying out any longer.

Q. You stated above that the recommended OPC rate increase level would negatively impact the Company's service capabilities and reliability; please elaborate.

A. The FPU electric system earnings are a material part of the CUC corporate earnings. Market analysts follow the electric unit's performance and will be interested in the result of the rate filing. To the extent the Company does not receive a base rate increase that produces a fair and reasonable return, it is likely that such a result would be noted by analysts influential in evaluating CUC securities. Such evaluations could have a negative impact on CUC's overall ability to raise capital at attractive rates, including the capital FPU uses to make system improvements, address reliability, and customer service investments. To be clear, I'm not suggesting we would lose the ability to raise capital, but the costs would likely be higher; costs that would ultimately would be borne by ratepayers.

Q. Are there costs that cannot reasonably, be eliminated or deferred?

A. Yes. We would never compromise the safety of our distribution system or put employees in an unsafe situation. Following the merger, CUC expanded the FPU safety and compliance program. Last year three CUC business units, including FPU, won an American Gas Association safety award. FPU won in the combination utility (gas and electric) category. As noted in my direct testimony, safety is our foremost Service Standard and takes priority over anything else, including financial results.

It would also be difficult to cut existing operations staff. The electric division has fewer total employees today than it did ten years ago. However, a level of rates consistent with either of OPC's recommendations would force us to consider such drastic and unproductive measures. Finally, we operate the distribution system in accordance with applicable codes and regulations and would continue to do so.

Q. Has the Company made an effort to control costs?

A. As noted in my direct testimony, the Company has already taken numerous steps to increase operational efficiency and reduce costs in the electric system. We have reduced total employees, reallocated certain engineering and management costs to other operating units and renegotiated power supply contracts, labor contracts and other services agreements. Each of these actions has resulted in cost savings. Even with these cost savings, we are earning abysmally low returns that are well below the level required by investors and recognized as fair by this Commission.

Q. What are the practical implications if the OPC recommendation is adopted?

A. The consequence of OPC's recommendation is very negative. All companies make resource allocation decisions based on both operational and financial conditions. As described above, certain activities must be performed without fail. However, there are many non-critical maintenance items that can be deferred and completed over longer time intervals, (vegetation maintenance, vehicle and equipment maintenance, etc). In addition, many system investments can be deferred (pole replacements, substation equipment upgrades, underground distribution, etc.). Each of these maintenance and system investment deferral decisions has a consequence on the reliability and performance of the distribution system. Each decision negatively affects customers. Such cost reductions counter our desire to enhance system reliability. Moreover, cost-cutting in the storm hardening area would be inconsistent with the Commission's desire to ensure adequate storm hardening practices.

Other cost reductions could be realized by slowing the Company's current continuous improvement efforts related to customer service. Subsequent to the merger, CUC and FPU have worked hard to elevate the customer experience in the electric utility. Additional Customer Care representatives have been retained. Telephone systems upgrades are in place. Improvements to self-serve options via the Company's web site have been implemented. Remodeled payment centers have been completed in both operating divisions. A new Outage Management System is in place to provide better customer information during service interruptions. A professional, utility-focused after hours contact service has been retained to ensure reliable 24-hour contact service. Although we have made great progress, much remains to be done. In the absence of appropriate base rates, several planned future customer service improvements would likely be deferred.

Q. How does the reduced cost structure described above compare with the operating practices of the electric utility prior to the CUC FPU merger?

A. Prior to the merger with CUC, FPU was experiencing some financial distress. Management was exercising substantial cost control practices for both operating expenses and capital investments. Capital for non-revenue producing replacement or upgrade projects was extremely limited. Investments in equipment and facilities were deferred. Maintenance schedules had slipped. Important operating analyses were postponed (for example, relay coordination studies), IT, telephone and business operating systems (outage management, GIS/mapping, CAD design, etc.) were antiquated. There was virtually no strategic planning process. Business development and growth efforts were minimal at best. Opportunities to expand the customer base or develop innovative power supply opportunities were not pursued. It appeared the Company was operating on a day-to-day reactionary basis with no clear objectives or strategy to improve service delivery to customers. It is not surprising that in such an operating culture the Company was experiencing numerous employee issues, customer complaints and community difficulties.

Q. Do you believe the CUC merger has corrected these deficiencies?

A. I believe the CUC merger has started the Company down a path where continuous improvement is now part of the culture and service excellence standards govern our every action. As noted in the Company's direct testimony, we have made significant investments to improve system operation and reliability. Our customer service activities are much better, as evidenced by the reduction in customer complaints received by the Commission. Our relationships with the communities we serve are greatly improved. For example, I would note that we won a franchise dispute in our NW Division by receiving 70% of the vote in a public referendum. Employees are engaged and eager to serve customers. We negotiated a multi-million dollar reduction in our purchase power costs. Our customers directly benefitted from this reduction in rates. The Company's strategic and planning efforts are beginning to pay dividends; new opportunities for further power cost reductions and reliability improvements are under review. We still have a long way to go to achieve the level of service I think is reasonable. I would hate to see us stop the improvement momentum, but the OPC proposed base rates put us at risk of doing just that. Accepting OPC's argument results in poor returns that prevent us from making all of the necessary capital investment to enhance service to a standard expected of us from our customers.

Q. OPC seems to be particularly focused on corporate cost allocation increases and the Company's performance incentive compensation programs. Can you comment on these issues?

A. Yes. Other Company rebuttal witnesses will address specific costs, but I would like to provide summary comments. As describe above, there is a substantial difference in the operating philosophy of FPU prior to the merger compared to FPU today. The availability of CUC capital at reasonable costs has made a remarkable difference not only to our system performance, but also in the attitudes of the employees delivering services to customers. The Company is actively working to build the systems, processes and facilities needed to operate a modern, efficient and reliable electric system. As we move forward, it is entirely appropriate that we would require a level of resources beyond that found in FPU prior to the merger.

OPC expresses a concern that costs are greater than the historic trend levels based on A&G expenses in the 2008 rate case. Of course they are. They should be. They need to be. OPC, or at least its witnesses, ignore the fact that FPU was in many ways failing under the historic cost structure. OPC makes no mention of the significant improvements in service and community relations achieved under CUC's ownership. FPU's historic cost structure funded an inadequate number of HR employees and resources, a limited IT staff largely focused on keeping the billing system running and a corporate communications employee providing sales advertising support. Planning activities were focused more on cost elimination than on growth and innovation.

CUC recognizes the importance of the above functions in support of a healthy, efficient and growing company. Rather than duplicating A&G staff in each of its business units, CUC management has consolidated certain functions at the corporate level and allocated costs to business units accordingly. The increased cost allocations to FPU reflect increased service levels requested by the business unit. Several examples may be helpful. Deployment of more computers to operational employees has increased the need for IT support services. Telephone system improvements are handled by the corporate IT group. The significant increase in cyber security awareness and protection has also increased IT costs. In HR, it was impossible to continue to appropriately address employment issues for 300+ employees scattered across six Florida operating divisions (both electric and gas) with an inadequate amount of HR employees and resources. The corporate communications cost allocations include activities specific to Florida, but also reflect FPU's position as part of a larger corporate entity with greater public exposure. FPU's ratepayers reap the benefits of that association, and they should bear the related costs. The same is true of other corporate services such as accounting, finance and safety.

Q. What about the strategic planning and business development costs?

A. First, I think OPC has failed to appreciate the substantive services provided to FPU by these corporate groups. Strategic planning is fundamental to the CUC corporate culture and long pre-dates the FPU merger. The annual planning exercise and periodic updates are central to the operational excellence, growth and financial stability CUC has enjoyed for decades. This is not strategic planning solely for the purpose of growing revenue. A multitude of operational system improvements, service enhancements and procedural efficiency determinations result from the planning process. In addition, a continuous review of the code, regulatory, financial and market environments in which we operate is prepared. The corporate Strategic Planning group is actively involved in developing the business unit plans, and they serve as valuable resources for research, compiling and analyzing data and assessing industry and market trends.

The New Energy Development department was formed principally to look for new business opportunities. However, given the skill sets and expertise of the associated employees, FPU utilizes their services in a variety of ways. The development of financial models to evaluate electric-related opportunities and projects is largely performed by this department. As an example, FPU recently began an examination of several alternatives to our current wholesale power providers. One of these alternatives is [redacted] The New Energy Development group assisted in the evaluation of this alternative. Beyond the utilization of the group for specific electric system projects, I believe the recovery of a portion of their costs in rates is appropriate. A healthy, growing corporation provides better and ultimately lower cost services to customers. Developing new business opportunities is fundamental to such growth. As the corporation grows, fixed costs can be allocated over a larger base, effectively holding down cost increases for all business units. Managed growth promotes financial stability, increases capital access at lower cost and contributes to an engaged and motivated workforce. One only need look back prior to the CUC FPU merger for an example of what happens in a non-growth, financial distress environment. The cost allocations for New Business Development are appropriate and should be allowed.

Q. OPC suggests that a portion of the CUC and FPU employee incentive compensation programs should be denied since the program'S financial goals,

in OPC's view, focus on shareholder benefits and not ratepayer benefits. Please comment.

A. I reject the presumption that ratepayers fail to benefit when a Company's financial targets are achieved. A financially healthy, growing company provides great benefit to ratepayers. The example I sited earlier, the comparison of FPU prior to the merger to FPU subsequent to the merger, is an obvious example. Service levels improve and investments are made to continually upgrade facilities improving system performance; therefore, employees are more attentive to customers and myriad other operational improvements are implemented. That is not the case in a company that is struggling financially. Beyond the operational benefits, a financially sound company finds it easier and cheaper to raise capital and requires fewer rate increases – both to the ultimate benefit of ratepayers.

I would also argue that the OPC's suggested "ratepayer goals" (safety, customer service survey targets, etc.) are as important to meeting shareholder expectations as the financial goals are to meeting ratepayer expectations. Our investors expect to see safety and customer satisfaction. They realize we are in a service business. So, the goals that OPC maintains are ratepayer goals are also goals shared by our investors.

Similarly, market competitive compensation plans with performance incentives benefit customers every bit as much as they do shareholders. The total employee compensation targets, including base and incentive pay, are designed to be competitive with other employers in the markets we serve. We need to be competitive to retain our existing employees and hire new employees due to attrition such as retirement. We have quite an investment in our employees, an investment designed to serve our customers. If we fail to be competitive with our compensation, then it is our customers who will suffer from lost employees that we could have kept with properly designed, competitive compensation practices. The CUC HR Department conducts periodic studies to assess given market pay rates for comparable positions. Our compensation plan reflects market practices; more importantly, it serves our customers. Therefore, the cost of the CUC executive and FPU IPP incentive compensation programs should be fully recovered.

Q. OPC has recommended a 9% ROE and an imputed reduction in capital structure equity. Can you comment on this proposal?

A. Yes. First, OPC appears to hold the view that FPU's risk is less than that of other electric companies given that FPU does not own and operate power generation. I have not found that to be the case. FPU is unlike any other Florida IOU. It is currently dependent on third party providers for wholesale power. No other Florida IOU, and few municipal systems, depend fully on the wholesale electricity market to provide long-term, load following, full requirements power. The Company has experienced significant cost increases in its wholesale power agreements due to fuel volatility, changes in environmental regulatory requirements imposed after contract execution, and weather conditions that spiked demand quantities. The Company has limited ability to negotiate power supply agreements that transfer these risks to the supplier. In both divisions the Company has experienced significant customer and local government outcry at wholesale power cost increases passed through the fuel clause. In one instance, a municipality initiated legal action and a referendum seeking to terminate its franchise and force the sale of the Company's distribution system. It doesn't get much riskier than that. The risk I have outlined is greater than the risk faced by investor owned utilities that own their own generation.

The Company's electric system is small. For that matter, CUC is small compared to the very large electric IOU systems operating in Florida. Small companies are inherently more risky than larger companies. The limited ability to absorb customer and load loss (especially of larger core accounts), general lack of revenue diversity, economic slowdowns that affect growth or retention, and the wholesale power pricing considerations discussed above all define increased risks for small companies. With that said our obligation to provide quality service is no less important because we are a smaller company. All customers are important. We value our customers and will provide quality service regardless of the size of our customer base or the size of our company. To suggest that we have less risk short changes our customers. Again, this is not consistent with sound regulatory policy.

Finally, the OPC recommended ROE is inconsistent with recently authorized ROE levels for other Florida electric IOUs. They also propose an additional adjustment to arbitrarily lower FPU's equity percentage in its capital structure. Our capital structure is the capital that is invested in our Company. Investors who have invested their capital expect returns commensurate with the type of capital they have invested. OPC's suggestion that the Commission disregard a significant amount of equity capital actually invested and replace it with lower cost debt, is nothing more than a back door means of reducing the earned return on equity below the already unconscionably low level recommended by their witness. Adoption of OPC's recommendations would further erode the Company's ability to earn a fair and reasonable return on its investments.

Q. Please summarize your testimony on the impacts of receiving only what OPC recommends.

A. OPC's position is not grounded in sound economic or regulatory policies. The company has gone to great lengths to delay this filing as long as possible. It can delay no longer. Apparently, OPC is fine with returns well below what even their witness testifies is reasonable. Our investors tell us we cannot continue earning returns well below their expectations. But it is not our investors who have the last word here. We know that if we cannot attract capital or attract capital at reasonable rates, it is ultimately our customers who will suffer. Our investors can move their money elsewhere, but it is our investors who would be left with negative impacts on quality of service, reliability and customer dissatisfaction. So, a reasonable level of a rate increase is necessary to serve our customers as well as our investors.

The impact of higher capital investment in the business, and unavoidable but necessary cost increases, have lowered our returns to unacceptable levels. If the OPC recommended $1,996,096 were to be granted in this case, the Company would remain millions of dollars below the base rate revenue level needed to meet the service expectations of customers, let alone the return expectations of shareholders. The Company would have few realistic opportunities to reduce operational expenses and investments to mitigate the negative effects on earnings. The few steps that could be taken would have long term negative impacts on customers.

The Company would have little choice but to immediately begin preparing another request for rate relief, resulting in more rate case expense for the Company. Ultimately, this is not a good result for our customers who would bear this associated increased cost.

Q. Does this conclude your testimony?

A. Not quite. FPU strives to provide quality service to its customers. We are active in the community, and we promote economic development to better the communities we serve and grow our customer base. We are proud of our commitment to our customers. We have dedicated employees in these companies and through our employees and our management team including CUC, we have successfully kept our budgets lean. In fact, we have deferred this request as long as possible because of our hard work to do our best with what we had. The time has come to increase our rates to enable us to make the continued improvements that will continue to assure quality service. We can no longer defer our request for this increase in base revenues. OPC's recommendation has the same result – it only delays what has to happen – thereby, making it more expensive for the consumer in the long term. That is not in the best interest of our customers. This concludes my testimony.

Q. Please state your name, affiliation, position, and business address.

A. My name is Cheryl Martin. I am the Director of Regulatory Affairs for Florida Public Utilities Company (FPU) including the Florida Division of Chesapeake Utilities (Central Florida Gas or CFG), Peninsula Pipeline, and Eight Flags Energy, LLC (Eight Flags). My address is Florida Public Utilities Company, 911 South 8th Street, Fernandina Beach, Fl 32034.

Q. **Are you the same Cheryl Martin who filed direct testimony in this proceeding?**

A. Yes.

Q. Please state the purpose of your rebuttal testimony.

A. The purpose of my testimony is to respond to certain issues raised in the direct testimony of Donna Ramas filed on behalf of the Office of Public Counsel ("OPC") in this proceeding. Additionally, I will respond to the direct testimony of Jeffery Small filed on behalf of the Florida Public Service Commission Staff ("PSC staff") in this proceeding.

Q. **Please summarize the key issues and areas that you will address in your rebuttal testimony.**

A. In particular, I will address specific issues raised by OPC Witness Ramas related to the income statement and balance sheet as it relates to our Rate Proceeding and MFR filing. Specifically, I will address the following topic areas as outlined below:

1. Overall ROR (Ramas, page 4 and 79-80; DMR-2; DMR-3)

Balance Sheet

2. eCIS project in CWIP (Ramas, pages 4 – 9)
3. Accumulated Depreciation error (Ramas, pages 9 -11)
4. Deferred Rate Case Expense in Working Capital (Ramas, pages 11- 15)
5. Cash in Working Capital (Ramas, pages 15 – 16)

Income Statement

6. Forfeited Discounts/ Late Fees in Revenues (Ramas, pages 17 – 18)
7. Severance Costs (Ramas, pages 19 – 20)
8. Payroll Costs related to Severance Costs (Ramas, pages 20 – 21)
9. Marianna Litigation Bonus Payout (Ramas, pages 21 – 22)
10. IPP Bonus (Ramas, pages 25 – 26)
11. PTO (Ramas, pages 36 - 37)
12. General Liability Regulatory Asset (Ramas, pages 38 – 39)
13. General Liability Reserve (Ramas, pages 40 – 42)
14. Tree Trimming Expense (Ramas, pages 43 – 45)
15. Events (Ramas, pages 48 – 50, 52 - 53)
16. Property Tax Expense (Ramas, pages 76 – 78)
17. Interest Sync (Ramas, pages 78 – 79)

Other

18. Error in OPC witness Exhibits (DMR – 2 and 3)

Response to FPSC staff Audit report and Testimony

19. Finding 1 (Small, pages 6 – 7)
20. Finding 2 (Small, page 7)

Q. Do you have any exhibits to which you will refer in your rebuttal testimony?

A. Yes. A summary of those exhibits follows:

CMM-9	ROR Summary and Revenue Deficiency as of June 30, 2014
CMM-10	Severance Pay/ Vacancy Related Payroll
CMM-11	PTO Vacation Pay Liability
CMM-12	Summary of Revised Revenue Requirement

Q. Are the recommendations by OPC witness Ramas for a revenue requirement of $1,996,096 with an Overall Required Rate of Return of 5.56%, as reflected on Exhibit DMR-2 page 1, or her alternative recommendation of a revenue requirement of $2,314,651 with an overall Required Rate of Return of 5.74%, as reflected on Exhibit DMR-3, page 1, fair or appropriate?

A. No, absolutely not. If accepted, neither alternative would allow the Company to earn a fair and reasonable rate of return on its investment, which would impair the Company's operations and long-term financial position in myriad ways. That is not in the best interest of our customers. The Company has demonstrated that the revenue requirement and overall required rate of return are significantly greater than has been suggested by both OPC witnesses Ramas and Woolridge. The Company has presented its MFRs, testimony, and responses to numerous interrogatory and production of documents that further support our initial filing and revenue request.

<u>1. Overall ROR</u>

Q. Are the current rate levels of the Company adequate to support the ongoing

financial viability of the Company in a manner that will ensure it is able to provide service to its customers?

A. No, not at all. To the contrary, based on our most recent earnings surveillance report at June 30, 2014, the Company is clearly in need of rate relief and is earning well below the allowable rate of return, see Exhibit CMM-9, Surveillance Report June 30, 2014 and Revenue Deficiency at June 30, 2014. As of June 30, 2014, the Florida Public Utilities Company Electric Operations is earning an Average Rate of Return of 3.56%. The midpoint allowable rate of return is 6.69%. Using the net operating income multiplier and allowable ROR in our MFR filing (Schedule A-1), as updated for the rate base and NOI from our actual year-end Surveillance Report, the revenue deficiency at June 30, 2014, is $3,760,129. This indicates that the Company continues to earn a return well below its allowable rate of return. For the projected test year ending September 30, 2015, the Company will be even further below its allowable rate of return as it continues to decline.

2. eCIS Project in CWIP

Q. **Does the Company agree with the conclusion of OPC witness Ramas, as discussed on Pages 5 and 6 of her testimony, that the Company has failed to demonstrate that the appropriate eCIS project estimate is $13.6 million, not the $8.5 million that was a prior estimate?**

A. No. As also explained in the Company's responses to the OPC's Interrogatories Nos. 94 and 96, the eCIS project team revised its estimates of the total project costs, to include any costs beyond 2014. The newest, most accurate estimate is $13.6 million. This estimate was provided by the Consultant, Five Point Partners LLC.

The table below provides specifics regarding the remaining costs expected in the eCIS project. As we proceed with the remaining implementation effort, we continue to monitor and revise this project estimate. It is possible that the actual costs may exceed this estimate; however, this is the most current estimate available.

Estimated itemized listing of remaining projected costs by cost type:

Table CMM 1.0

Cost Type	**TOTAL Project Estimate**	**Remaining Costs to be spent on Project**
Infrastructure	$340,000	$0
Application License	$510,000	$0
Application Maintenance	$170,000	$0
Application Services	$1,360,000	$360,000
SI Services	$5,100,000	$2,550,000
Third Party Services	$1,360,000	$1,360,000
Utility Services	$2,890,000	$1,445,000
Utility Expenses	$510,000	$510,000
Other Products and Services	$1,360,000	$1,360,000
Total	**$13,600,000**	**$7,585,000**

Because the consultant has revised the estimate for the eCIS project, the Company will update its internal budget for 2015 to reflect this or any new revised estimate for the eCIS project once it has been finalized.

Q. Related to the testimony provided by OPC witness Ramas on page 7 of her testimony, did the Company fully explain why the vendor was chosen for the eCIS project?

A. Yes, in response to OPC's Interrogatory No. 98, the Company described in detail how the Company selected the eCIS system it is implementing. As stated in that response, at the time the project was started, the eCIS system was currently in use within the Company and the project was considered an upgrade from ECIS to eCIS+ with the current vendor. The eCIS software had been well-established at FPU prior to Chesapeake's acquisition. FPU and the vendor had formed a long term relationship as well and the vendor had the most knowledge of our current system. After the acquisition, Chesapeake decided to implement the eCIS system to its Florida division (d/b/a Central Florida Gas or CFG), FPU's sister natural gas system, for consistency and efficiency in the customer billing process for regulated entities in Florida. CFG was successfully migrated over to the eCIS system, giving the Company a better understanding of the eCIS system. After many discussions with the vendor, demonstrations, and visits with companies outside of our Corporation using the most current version, it was determined that an upgrade would meet our desired goals and would be the most beneficial from a cost stand point versus a completely new system implementation.

Q. Should the Company be allowed to recover the requested $13.6 million in rate base rather than the amount suggested by the OPC witness Ramas on page 9 of her testimony?

A. Yes. The Company is currently in the process of fully implementing a billing system across the Corporation for use in the regulated utilities. The Company has updated its estimate and is moving forward with a full implementation of the eCIS system. At this time the system is expected to cost $13.6 million, and will be in service by October 2016. An adjustment is simply not warranted based upon the difference between an initial estimate and a revised estimate. This is an ongoing project with prudently incurred costs. The project directly benefits our customers. As such, the best, most recent estimate of the project's costs is the amount that should be allowed for recovery in rate base.

3. <u>Accumulated Depreciation Error</u>

Q. Do you agree with witness Ramas' recommended adjustment to reduce rate base by $260,824 for vehicle retirements on page 11, lines 11 through 16?

A. Yes, I do. The Company duplicated the retirement for Transportation Equipment-Heavy Trucks in the MFR for the projected test year ended 2015, which we agree was an error. Since this was a retirement, it was a debit to accumulated depreciation in the MFR's. Therefore, rate base in the MFR's was overstated by the $260,834 and should be reduced. It is also important to mention while this adjustment to rate base is appropriate, there are also additional items that require an increase to rate base as a result of the audit performed by the Commission's Staff and presented by Commission Staff witness Small, which will be discussed later in my testimony.

4. Deferred Rate Case Expense in Working Capital

Q. Do you agree with witness Ramas' recommended adjustment on page 14, lines 21 through 25 and page 15, lines 1 through 7, to remove deferred rate case expense from rate base in this case?

A. No. The Company's position in this case is consistent with the Commission's prior policy statements on this issue with regard to FPU's electric division. Specifically, in the 1993 FPUC Electric Rate Case, Docket No. 930400-EI, Order No. PSC-94-0170-FOF-EI, pages 9 and 10, the Commission stated:

> We believe that the company should be given the opportunity to recover prudently incurred costs. Not including the unamortized portion of rate case expense in working capital is a partial disallowance. It is analogous to allowing depreciation expense, but not allowing a return on rate base. Rate case expense is a cost of doing business not unlike other administrative costs. Further, PSC rules, such as the MFR rule, influence the level of rate case expense. We believe that if it is determined that rate case expense is prudent and reasonable; the company should be allowed to earn a return on the unamortized balance. Rate case expense is a necessary expense of doing business in the regulated arena. As such a utility should be allowed to earn a return on its unamortized balance.

Although witness Ramas referenced another Commission Order involving our natural gas division in which the deferred rate case balance was not allowed, it is important to note that the referenced Order was a proposed agency action decision, which was ultimately protested by the OPC. Ultimately, that case was resolved through a stipulation and settlement between the OPC and the Company.

Q. Do you agree with Witness Ramas' statement on page 15, lines 2 and 3, that "it would be unfair for customers to pay a return on the rate case costs incurred by the Company in this case when the costs are being used to increase customer rates" or that the exclusion shares the costs of the rate case with the shareholders?

A. No, I do not. Rate case proceedings are the only means available to regulated utilities for the recovery of cost increases incurred while operating in the regulated business environment. The Company does not staff at a level that allows it to prepare the full rate case proceedings with internal staff. If the Company were staffed at such a level, the associated staffing costs would normally be allowed for recovery in the Company's Operating and Maintenance ("O&M") expenses. The Company instead utilizes consultants on an "as needed" basis, and has only incurred prudent, necessary expenditures as part of rate case expense. The Company has found that incurring periodic costs for rate case expense results in overall lower costs than would otherwise be incurred if the Company staffed at a level that allowed preparation of a full rate proceeding using only internal resources. As such, expenses incurred for rate case proceedings must be considered an ordinary, prudent and necessary cost of doing business in the regulated utility environment. Therefore, the related, unrecovered deferred portion of such costs should not be excluded from working capital.

Q. Have there been electric and gas cases where the Commission has allowed deferred rate case costs in the working capital allowance?

A. Yes. In fact, disallowing recovery of deferred rate case costs would be entirely inconsistent with a series of long-standing Commission decisions relating to FPU. For instance, the Commission's final order in the 2007 FPUC Electric rate case, Order No. PSC-08-0327-FOF-EI, page 33, issued in combined Dockets Nos. 070300-EI and 070304-EI, states:

> Our practice in prior rate cases, including FPUC's is to allow one-half of the rate case expense in Working Capital. Based on the above, we find that the appropriate balance of deferred debit rate case expense to be included in Working Capital is $303,400.

The above is likewise consistent with Commission Order No. PSC-04-1110-PAA-GU, issued in the 2004 FPUC Natural Gas Rate Case, Docket No. 040216-GU, at page 27, in which the Commission stated:

> In addition, one-half of the unamortized rate case expense … shall be included in unamortized rate case expense in working capital for the projected test year.

This is also consistent with Commission Order No. PSC-04-0369-AS-EI, issued in the 2003 FPUC Electric rate case, Docket No. 030438-EI, and Commission Order No. PSC-95-0518-FOF-GU, issued in the 1994 FPUC Natural Gas case, Docket 940620-GU, in which the Commission also allowed recovery of one-half of the unamortized rate case expense.

Q. Is allowing one-half of deferred rate case expense in working capital appropriate?

A. Yes. Allowing one-half of the deferred expense takes into account the fact that, at the end of the amortization period, the deferred expense account will be zero. Therefore, the Company's inclusion of the $346,028 consisting of one-half of unamortized deferred rate case costs is appropriate.

5. Cash in Working Capital

Q: Does the Company agree with the recommendation of OPC witness Ramas on page 16, that an adjustment should be made to reduce cash included in working capital?

A. No. The cash amount suggested by witness Ramas of $100,000 is not sufficient to meet the Company's day to day cash requirements. The Company has appropriately projected cash for the projected test year based on trending the actual electric thirteen-month historical average balance of cash at September 30, 2013, which is $501,251. When escalated by customer growth, the amount for the projected thirteen month-average cash balance would be $504,312 at September 30, 2015.

The Company maintains sufficient cash for use on a day-to-day basis. The amount of cash in working capital is intended to provide for the current requirements, not for any long-term capital requirements. The Company has a cash management system that provides for an automatic pay down of short-term debt once deposits are cleared from the customers' banks. When a customer's payment is received, the accounts receivable is reduced and cash is increased. However, those funds have not yet cleared the customer's bank, and they remain in the Florida depository account until they are available to transfer into Chesapeake's main bank account for use in paying down the short-term debt.

Again, the Company's cash needs fluctuate on a daily basis as result of fuel costs, payroll costs, and other operating costs that the Company pays with cash. . Using a thirteen-month average provides a reliable, conservative basis to normalize the cash balance and the cash requirements for use in rate base. Thus, considering the cash management programs the Company has in place, a thirteen-month average balance of cash on a historic basis, increased for customer growth, does provide a good estimate of the amount necessary for use in working capital.

Q. Does the Company agree with witness Ramas on page 16, that the cash balance has increased significantly since the last rate proceeding?

A. No. Although the thirteen-month average cash projected in this rate proceeding represents an increase above what was approved in the last rate proceeding, the Order in that same proceeding, Order No. PSC-08-0327-FOF-EI, page 25, recognizes that the prior period cash in the 2006 historic year for that same case was $247,509. By way of demonstration, when an average increase of 3% is applied to that 2006 historic period amount to account for inflation and customer growth over the intervening 9 years, cash for the projected test year 2015 would be $322,940 simply as a result of escalating the prior 2006 rate case amount. This clearly demonstrates that the cash balance expected in our projected test year ending September 30, 2015 has not increased "significantly" over the prior rate proceeding.

7. Severance:

Q. Do you agree with witness Ramas, at page 19, that the historic test year and projected test year expenses include costs for employee payouts?

A. No. Witness Ramas is incorrect. In preparing the MFRs, the Company assumed that the severance costs in the historic year offset the lack of payroll and related benefits expenses while the positions were vacant in the same historic year. Therefore, in projecting the test year ended September 30, 2015, the assumption was made that severance costs were excluded and that only salaries and related benefits for the replacements of positions remain. In other words, the payroll projected for the test year is reflective of actual compensation paid for active employees.

The Company did not provide a separate audit trail reflecting the removal of the employee payouts followed by recording the additional payroll that resulted from the temporary vacancies created by said positions. While these items were not shown on the "Over and Under" adjustments on MFR Schedule C-7, the amounts were expected to offset each other so that total payroll as projected for the test year was appropriate. Although the Company accounted for employee changes that occurred during the historic test year for new hires, organizational changes, or revised employee allocations on MFR Schedule C-7, none of those employee changes were related to the temporary vacancies associated with the voluntary exit program.

Upon additional review, the Company does agree that, looking at these items separately, an adjustment could be made to reduce O&M expenses for the difference between the severances paid and payroll shortfalls during the historic year due to the temporary vacancies created by the severances. A detailed analysis calculating the impact of the severance costs and the temporary vacancies associated with these payouts, for the historical test year and projected test year, along with more detailed information regarding the specific positions involved in the temporary vacancies due to the severance, is set forth on Exhibit CMM-10 and the amounts are summarized below.

	HTY 09/2013	PTY 09/2015
Reverse Severance Payouts	($119,669)	($127,628)
Add Vacant Positions to C-7	$ 83,802	$ 89,364
Total Adjustment	($ 35,867)	($ 38,264)

Q. **Do you agree that the severance costs should be removed from the projected test year as recommended by witness Ramas on page 21?**

A. No. Although the Company's severance costs were not a "dollar for dollar" offset by the reduction in payroll, as demonstrated on Exhibit CMM-10, it is not appropriate to remove the full value of the severance costs from the projected test year, as recommended by witness Ramas on page 21. These costs were, in fact, offset by payroll associated with the temporary vacancies that existed at the time of the voluntary exit program. Therefore, the projected test year expenses should be reduced by only $38,264, which is the difference between the projected test year expenses of ($127,628) and the payroll increase for the vacancies $89,364.

8. Forfeited Discounts/Late Fee Revenues

Q. Do you agree with OPC's witness Ramas on pages 17 and 18, that the amount of revenues included in Account 450 – Forfeited Discounts for late payment revenues in the test year should be increased by $55,349?

A. No. The net effect to revenues during the historic year would have been zero. Specifically, the refunds were made in conjunction with an extraordinary event that caused an increase in late fees due to an issue with the payment remittance envelopes, which was a problem outside of our customers' control. Consequently, subsequent refunds were made to customers for those same late fees. The details of the event are that, in March 2013, the Company experienced a delay in receiving mail (namely bill payments) due to an error regarding the P.O. Box address printed on customers' payment remittance envelopes. A decision was made to refund all late payment charge fees associated with this event for this time period, because this event was beyond the customer's control. As such, it was not appropriate for us to charge our customers late fees. To remedy the event, late fees were refunded in recognition that this was an extraordinary event. The actual historic test year late payment revenues of $380,000 are, therefore, an accurate reflection of the historic test period.

Q. Can you further explain why it would not be appropriate to increase late fees for the refund made associated with the abnormal mail event?

A. It would not be appropriate to increase the late fees for the refunds that were given to customers as a result of this extraordinary event, because the refunded amounts were already booked to revenues as a result of this abnormal event. In other words, since this mail delay was not normal late fee revenues were already booked to revenues, before any refunds were made to customers. As such, late fee revenues were overstated by $55,000 for the mail delay. The refunds made to customers as a result of this mail delay, simply reduced the overstated revenues. Consequently, the refund to customers had the effect of normalizing the late fee revenues on the Company's books. Thus, using the net amount of late fees in the historic year for projection purposes as a basis for the projected test year is appropriate. This requires no adjustment, because the effect of the adjusted late fees was to exclude the abnormal event. To make an adjustment to add the refunds to late fee revenues would be erroneous and would result in overstated late fee revenues for the mail delay event.

9. Marianna Litigation Bonus Payout

Q. Was witness Ramas correct on Page 22, with respect to the Bonuses paid to employees in the Marianna division?

A. No, the Company should not be required to adjust its projected test year for the removal of incentive pay. Although the goals surrounding the incentive pay may change from year to year, employees are eligible to earn incentive pay each year if they meet or exceed established goals.

Some employees received a portion of their incentive pay during the historic year, primarily as a result of additional efforts required during the litigation and settlement process associated with the Company's franchise dispute initiated by the City of Marianna. The total associated with bonuses for this effort is approximately $24,000. To be clear, no salaries or benefits, such as bonuses, were recovered as part of the litigation cost regulatory asset established in Docket No. 120227-EI.

Consistent with our Performance Plan, these bonuses were appropriate in that they provided an incentive and reward to those employees who helped the Company achieve one of its annual goals, which in this instance was retention of the Marianna service area. Making a portion of "pay" part of an incentive plan based on achieving goals is effective in ensuring that our employees meet the highest of standards in performance. Moreover, in this instance, the high standards of performance that were achieved enabled the Company to retain a significant portion of its Northwest service area, the loss of which would have had serious implications on the Company as a whole, including its remaining ratepayers, due to the allocation of costs over a smaller customer base.

10. Incentive Pay Plan ("IPP") Bonus

Q. Do you agree with witness Ramas' testimony on page 32 that an adjustment to the IPP expense is necessary for the projected test year 2015 for the FPUC

electric operations?

A. No. Adjusting the IPP expense, and penalizing the Company for properly compensating employees in order to retain skilled employees and attract similar new employees, is neither fair nor reasonable. Our overall compensation package, including both base salary and IPP bonus, is comparable to the market levels. In order to ensure it remains consistent with the market, our Human Resources ("HR") department, with the assistance of outside consultants, periodically reviews the compensation plans to insure we remain competitive in our ability to retain and attract skilled employees.

As also noted in the rebuttal testimony of Company witness Kim, an incentive pay plan is an important component of compensation. Incentive pay, which is variable pay, is not a guarantee and, is at risk until such time as both the Company and the employee achieve the goals associated with the variable pay. If the organization did not have a variable pay program, then, in order to attract future employees as well as to retain current employees, the organization would be forced to raise base pay rates to remain competitive. The Company would also lose an effective tool for motivating employees to use their best efforts to achieve organizational goals.

Although a portion of the IPP is based on achieving financial targets and goals, this still directly benefits the customers in our electric operations, which the Commission has recognized in prior cases. In my experience, the IPP helps ensure that we keep focused on the Company's critical objectives, such as customer service and safety, achieving financial targets, keeping costs low, attracting new customers, and making our business processes as efficient as possible, all of which directly benefit our customers.

The Company is also providing the rebuttal testimony of witness Jim Moss, which includes additional support for our Incentive Pay Plan, as well as our overall employee compensation package.

11. Paid Time Off ("PTO")

Q. Do you agree with witness Ramas' testimony at pages 36 and 37 that the one-time reversal of PTO should not have been removed from the historic year?

A. No. As previously addressed in our initial filing, beginning on page 33 of my direct testimony, a one-time reversal of the total accumulated PTO liability on the books in the historic year period was booked in the 2013 calendar year. The accumulation of this liability occurred over the last several decades. As such, the one-time reversal that occurred during the historic year relates to prior period expenses and does not belong in the historic year. The Company removed the PTO expense reversal in the historic year, because this liability had been accumulated over many years since the very inception of the old PTO policy. Thus, the reversal that occurred during the historic year actually removed in one calendar year a liability that had accumulated over several decades. This is properly characterized as a prior period adjustment, and as such, does not belong in the historic year for purposes of reviewing expenses or for purposes of trending expenses forward to project the September 30, 2015 test year payroll expenses.

Q. Do you agree with OPC witness Ramas' suggestion beginning at page 36 that the PTO expense associated with the reversal of the old PTO policy should be established as a Regulatory Liability, amortized, and returned to customers through reduced O&M expenses in this rate proceeding?

A. No. Although the former PTO policy was in place during the prior rate proceeding, only the normal change in vacation pay expense was used to determine the expense embedded in the current base rates. The change in expense associated with PTO expense in the projected 2015 test year accurately reflects what will be incurred as expense. Also, it is critical to note that the entire liability was not previously recovered in base rates nor was it ever established as a regulatory asset. The initial recognition of the liability was made as a result of an interpretation made by the external auditors of FPU under GAAP. At that time, FPU made a one-time accrual to reflect the liability of the PTO reserve, and FPU did not receive recovery for that initial recognition. As the reserve changed each year, an accrual was made to reflect the change in PTO reserve. Because the initial liability related to the PTO amount was never established as a regulatory asset nor recovered in base rates, it would not now be appropriate to create a regulatory liability and allow for amortization.

Q. Are any additional adjustments necessary to address any remaining portion of the PTO liability?

A. No. Although a portion of the PTO liability was included in the last projected test year (2008), it was only for the portion of the liability that changed during the last historic year (2006) multiplied by the projection factor. For Electric, the amount of PTO expense in the prior 2006 case historic test year was $16,107, which accounted for the change in vacation pay expense embedded in O&M expenses. When this amount is trended to the prior projected test year (2008), the projected amount would have been $18,732. Please see Exhibit CMM-11, which is an analysis detailing this amount and previously provided to OPC in response to discovery requests.

Under the old PTO policy, the amount to be paid on the liability was accrued in advance of the year it would be paid. As such, accrued vacation pay was built up over a long period well after the initial recognition on the liability. Each year, only the additional hours earned in the upcoming year, in total, by the employees at the new rate of pay, were added to the vacation pay liability reserve and expensed in that year. The amount would then be expensed based on the current year's payroll.

Upon changing the PTO policy, a one-time credit to the books was made in order to reverse the accrued vacation pay liability. Because this was done to address a multi-year accrued liability, as explained, this reversal is truly a prior period adjustment for which no further adjustment should be made. Again, to be clear, the initial recognition of the liability was never embedded in base rates. Moreover, this reversal occurred over the calendar year 2013 and was reversed in a manner to follow the use of the vacation pay that year. As a result, instead of booking an expense for the vacation pay during 2013, the Company utilized the reserve for this year only. Going forward, however, the Company will expense vacation pay as earned in the same calendar year and will only recognize a vacation pay liability for that same calendar year, as it is earned, minus any vacation pay taken.

Furthermore, creation of a regulatory liability associated with the PTO liability that was reversed during 2013 would create a significant financial reporting issue for the Company with respect to this amount. If the Commission determines that O & M expenses should be reduced for a portion of this prior expense, the recovery amount should be adjusted, but in no event should the Company be required to establish a regulatory liability for this PTO policy change.

12. General Liability Regulatory Asset

Q. Do you agree with Witness Ramas' position regarding the large liability claim paid during the 2013/2014 calendar year period?

A. No. Witness Ramas indicates in her testimony beginning at page 39 that the Company did not sufficiently support the large claim paid. In response to discovery, the Company did, however, provide copies of the actual invoices paid to the insurance carrier for the deductible portion of the liability claim. Without disclosing protected information, the Company can confirm that the "one large insurance claim" referenced in the Direct Testimony of Matthew Kim stems from

an electric incident that occurred in July 2012 and that the final payment pursuant to a confidential Settlement Agreement was made in February 2014 related to this matter. The Company paid a total of $250,000 on this claim.
The Company is precluded by the confidentiality provisions of the referenced Settlement Agreement from providing further specifics of the event or terms of the Settlement Agreement. Providing this additional information could constitute a breach of the Agreement. To be clear, it was the Company's insurance company that determined the terms of the settlement arrangement with the claimant. FPU can only provide such information if it is otherwise ordered to do so by a court or agency of competent jurisdiction.

Witness Ramas suggests that the Company did not provide sufficient evidence that the cost related to an electric matter; however, to the extent allowed by the confidential settlement agreement, the Company confirms the details outlined above.

With regard to the Company's request to be allowed to establish a regulatory asset for purposes of amortizing the referenced large electric general liability claim that was paid over a 2013/2014 time period in the amount of $250,000, the Company should be allowed to establish this asset and amortize it in expense over a five-year period for purposes of setting base rates. The five-year period is the normal period between rate proceedings, and as such, this period for amortizing the expense is appropriate for rate setting purposes as well. The amount paid in settlement of the claim is appropriate for recovery in that it is an amount prudently paid out to settle a claim against the Company involving its electric division. The Company did not receive recovery for this type of expense in its prior rate proceeding.

13. Self Insurance Reserve for General Liability Claims

Q. In addition to establishment of a regulatory asset and amortization of the historic year claim over a five-year period, the Company requested establishment of a general liability reserve to cover future claims. Do you agree with witness Ramas' conclusion at page 42 regarding the amount that should be allowed annually for purposes of establishing a reserve or amount of general liability expense?

A. No. The Company instead believes that the large claim that has been incurred in recent history should be used as a basis to establish a reserve for future claims. This claim should be averaged over five years, rather than the five and a half years suggested by witness Ramas. In addition, although witness Ramas looked at the average of small claims over the last 5½ years, those claims embedded in the average should have been inflated to today's dollars. The Company does agree with witness Ramas that history can be used as a basis to estimate the annual expense; however, the average annual amount of general liability expense she recommends of $54,289, page 42 of her testimony, is not the average that would be expected annually over the next five years. The Company has estimated that on average over five years claims will be $70,000 annually.

Certainly, the Commission will retain the right to adjust the future accruals for this reserve if accruals are either too large or too small to cover future claims; but, for the initial establishment of the reserve, the Company has proposed a reasonable basis for that initial five-year period. The Company's request is consistent with the similar reserve request already in place and approved by the Commission for FPUC Natural Gas. This reserve amount would cover future general liability claims. Therefore, the Company seeks approval to accrue $50,000 per year to cover large claims, and $20,000 of smaller claims on an annual basis for the basis of the self-insurance reserve. This expense has been reflected in O&M expenses as a direct projection.

Q. **Does the Company agree with the OPC witness Ramas' assessment at page 41 that establishment of a GL reserve would result in less scrutiny on claims charged to this reserve?**

A. No. To the contrary, the claims charged to this reserve would be subject to an audit and review by the Commission's staff. Specifically, the Company anticipates that the Staff would review claims charged to the reserve in the Company's next rate proceeding. I also strongly disagree with the suggestion at page 41, line 10 of her testimony that the Company may charge amounts over the level covered by insurance to this reserve in error. There is simply no basis for this assumption and the witness makes no attempt to propose one. At best, this appears to be an attempt by the witness to persuade a result based solely on her opinion as to the best approach, with no analytical or other objective analysis or experience to sustain it.

Again, the establishment of a reserve of this type and level is consistent with that which has been previously approved for the Company's natural gas division, is consistent with reserves established for other Florida utilities, and is in line with industry practice. Moreover, it is a prudent approach to risk; in the event that a substantial claim is filed, the Company will be prepared financially. It is impossible to avoid all risk, but establishing a general liability reserve will protect against unnecessary risk, which ultimately, protects both the Company and its ratepayers.

As always, the Commission's Staff will have the ability and opportunity to review any charges covered by this reserve in future proceedings. As such, there is appropriate regulatory protection and assurance that the Company will properly utilize the reserve for future electric claims. Contrary to witness Ramas' assertions, I believe that the establishment of a liability reserve for future claims provides greater regulatory protection, as compared to allowing a specific level of expenses embedded in the base rates, because the reserve mechanism provides the Commission and its staff with a better defined avenue to scrutinize specific charges against the reserve in future proceedings.

Q. What is the total amount of General Liability expense that should be allowed for purposes of setting base rates in the projected test year ending September 30, 2015?

A. The Company should be allowed $50,000 for purposes of amortizing a regulatory asset associated with a large claim paid to the insurance company for the deductible of a claim paid during the 2013/2014 time period. In addition, for purposes of establishing a reserve to cover future general liability claims, the Company should be allowed a total of $70,000 annually, composed of $20,000 annually to cover small claims, and $50,000 per year to cover larger claims.

14. Tree Trimming

Q. Describe the methodology used by the Company to project tree trimming expense.

A. Due to the monthly fluctuations of this expense, the Company determined that the straight-forward methodology for making this projection was to use an estimate to normalize the average annual amount or typical monthly expense for tree trimming. Based on Company experience, it was determined that the historic year should be adjusted by $50,500 to normalize the tree trimming expenses for the projected test year. The difference between the historical year amount ($828,915) and the normalized historic expense ($879,466), or $50,500, was added as an "Over and Under" adjustment on MFR Schedule C-7 after trending.

Q. **Is the Company's proposed level of tree trimming expense for the 2015 projected test year reasonable?**

A. Yes. The Company expects this trend to continue as the Company continues to comply with the PSC requirements for tree trimming along all main lines every three (3) years and along all lateral lines every five (5) years. During 2013, the Company was able to accomplish all required tree trimming work scheduled for the vegetation management cycle, in addition to responding to all "hot spot "trimming and danger tree removals reported during the year. We have also improved our trimming methods, which has resulted in improvements in our reliability indices. The number of outages after storms and high wind events has decreased noticeably as a direct result.

Q. Do you agree then with witness Ramas' proposed adjustment to remove the $50,500 normalization adjustment from the projected test year, as reflected at page 45 of her testimony?

A. No. The Company's proposed level of tree trimming expense for the projected test year is reasonable based on the Company's expectations about the amount of tree trimming required.

15. Events

Q. Do you agree with Witness Ramas' recommended adjustment for the Winter Event on page 70 line 15 through 17?

A. No, I do not. The Winter Events include presentations by the officers and senior managers of the Company and are used to show appreciation to the employees, inform them of the status of the Company as a whole, and acknowledge them for their achievements and impacts to the Company. In addition, motivational presentations are made to encourage employees to continue to provide great customer service, both at an internal and external level, and to identify and implement further customer experience enhancements. Employees are recognized for meeting these goals at the events. In addition, these meetings give the employees an opportunity to network with their peers and strengthen relationships, which improve teamwork, and customer service.

According to Witness Ramas' testimony, there are more economical ways and locations for employee appreciation and informative events than those used by the Company. On this basis, she recommends that the entire expense associated with the Winter Event be removed from the historic test year. However, the cost of the Winter Event included in the projected test year, $17,968, when divided by the 69 full time equivalent electric employees, amounts to a mere $260 per person for this key event. This is a very small amount for an event that can be considered both an employee benefit and Company motivational tool, which does ultimately have a beneficial impact for customers.

Disallowing this expense would remove an effective and relatively inexpensive tool from the Company's toolbox. In fact, it removes two: (1) an effective employee communications, motivational, and morale tool; and (2) an additional compensation tool for attracting and retaining qualified employees. As such, I believe that witness Ramas' recommendation should be rejected.

16. Property Tax Expense

Q. Do you agree with witness Ramas' recommended adjustment to property tax on page 78, line 7?

A. No. Witness Ramas recommended increasing the property tax expense by the annual average percentage change since 2010. Increases in the property tax basis are, however, governed by the property appraiser's value assessments, which may or may not follow the market. In addition, land and buildings are valued separately from other property. The Company recognizes that property taxes will usually follow trends in plant. To the extent, however that the general real estate market tends to impact property values the Company believes that the property taxes could, potentially, exceed plant trends as the real estate market rebounds from the recent historical decline.

In addition, witness Ramas has acknowledged in her testimony that a new building could put upward pressure on property tax expense. She has made the further assumption that the building, which is projected to be sold, should offset the impact of the new building for property tax purposes. This assumption is not valid, and the witness offers no basis for it.

Witness Ramas' analysis is flawed for a couple of reasons. First, the cost of the old building is not equivalent to the cost of the new building. The retired building, which was not at all adequate to meet the needs of the Company, and was very old, is appraised at only 16% of the cost of the new building. Second, the County can assess new construction higher than old construction. In the Company's experience throughout its Florida operations, many Counties increase property tax values and assessments due merely to shortfalls in their respective budgets. According to a December 14, 2010 article by Cindy Perman of CNBC, this is one of the biggest reasons why, even in an economic downturn and housing-market crash, property taxes can rise.

Therefore, the Company believes that property taxes will increase, not only by the amount of property subject to property taxes, but also by any rate increases imposed by various municipalities. As such, the inflation factor, multiplied by the plant growth factor, is the most accurate basis upon which to reflect the expected increases imposed by taxing authorities on property taxes. As the Company noted in its response to OPC's Interrogatory Number 45, both the taxable basis and the tax paid have increased each year. Expected deficits in municipal and state budgets increase the likelihood of even higher property tax assessment rates, which we have not taken into consideration in this projection. When all these factors are considered, it is clear that the Company's approach to making the property tax projection is more properly grounded in real-life factors that impact the tax assessment changes, as compared to the approach of witness Ramas. Therefore, witness Ramas' recommended adjustment should not be made. Instead, the Commission should conclude that the appropriate property tax projection is the $690,483 included in the Company's filing.

17. Interest Sync

Q. Do you agree with Witness Ramas' adjustment to Interest Sync calculations in Exhibits DMR-2 page 23 and DMR-3 page 3?

A. Witness Ramas' calculations are based on adjustments to rate base and the weighted cost of debt proposed by OPC. The interest synchronization is a fall-out issue, which needs to be computed once rate base and cost of capital are finalized. The interest synchronization adjustment of $(457,129) in the filing is correct if no adjustments are required to rate base or cost of capital.

18. Other

Q. Did you find a problem with Witness Ramas' Summary of Adjustments on DMR-2, page 7?

A. Yes. On line 10, witness Ramas removed $55,500 for the tree trimming normalization adjustment. However, in her testimony on page 43, line 22 and in the Over and Under adjustment detail in the Company's filing, the amount of the normalization is $50,500. After taxes, the net effect of the difference is $3,071. This difference also changes the calculation of increase in base rate revenues on DMR-2 page 1. The correct amount for Line 8, column (B) would be $2,030,129 and line 10 would be $1,999,167.

Response to FPSC Staff Audit Report and Testimony

19. Audit Finding 1

Q. Do you agree with witness Small's adjustment for Audit Finding No. 1 on page 6 lines 21 through 25 and page 7 lines 1 and 2?

A. Yes, the Company agrees that the adjustment to the filing to remove non-regulated operations should be corrected, which results in an increase in rate base of $9,053, an increase in depreciation expense of $389, and a reduction to income tax of $150.

20. Audit Finding 2

Q. Do you agree with witness Small's adjustment for Audit Finding No. 2 on page 7 lines 3 through 11?

A. Yes, the incorrect vehicle depreciation rates were used. An adjustment made to the filing to correct the rates was incorrect. The audit report concluded that, as a result, rate base was understated by $33,831, depreciation expense was understated by $17,401, and income tax expense over-stated by $6,713. Based on the general ledger balances, it appears the audit report is correct.

Q. **Please summarize the Company's position of what rate base, net income, cost of capital, and revenue requirement should be for the projected test year ending September 30, 2015?**

A. The Company has determined that some adjustments are necessary to its original filing, including those recommended by witness Small, as well as some recommended by witness Ramas. We have prepared an exhibit summarizing those adjustments and the impact to the revenue requirement, which is attached to my testimony as Exhibit CMM-12. The adjusted revenue requirement necessary for the projected test year ending September 30, 2015 is now $5,806,219, a reduction of $45,952 from the Company's original request.

Q. **Does this conclude your rebuttal testimony?**

A. Yes.

REBUTTAL TESTIMONY OF JIM MOSS

ON BEHALF OF

Florida Public Utilities Company

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

A. I am Jim Moss, founder and Managing Director of PRM Consulting, Inc., a human resources, employee compensation and benefits consulting firm. My business address is 1814 13th Street, N.W., Washington, D.C. 20009.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. In 1970, I received a Bachelor of Arts degree in philosophy from Morehouse College. I also pursued graduate studies at New York University.

I have approximately 40 years of consulting and corporate human resources experience with a wide variety of public sector, quasi-government, for-profit and not-for-profit organizations, including several regulated utilities. Prior to founding PRM, I was a Principal and Practice Leader for the reward and recognition practice in Towers Perrin's (now Towers Watson) Washington consulting office. Towers Watson is one of the top three, largest international consulting firms in the world, which specializes in benefits, compensation and consulting firms in the world, which specializes in benefits, compensation and human resources. While at Towers, I conducted numerous executive compensation studies for such organizations as Baltimore Gas & Electric, Philadelphia Gas & Electric, Potomac Electric Power Corporation, and Virginia Power, and Washington Gas during my 23 year career with the firm. Before that, I was with RCA Corporation and Random House, Inc. for seven years, holding a number of positions in personnel, including Manager of Wage and Salary and Organizational Development.

I also have been a guest lecturer on human resources management at the graduate schools of American University and Johns Hopkins University. I have written and published articles on executive compensation, and have co-authored a human resources textbook for the American Society of Association Executives.

I am a member of World at Work, the Society of Human Resource Management, and the National Association of African Americans in Human Resources. I also received the Lifetime Achievement Award from the World at Work.

Q. HAVE YOU REVIEWED INCENTIVE COMPENSATION PLANS FOR OTHER UTILITIES?

A. Yes, not only have I reviewed several plans, I have assisted many companies in the development of incentive compensation plans as well.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut certain assertions made by OPC Witness Ramas about FPUC's compensation package. I will provide information, based upon my experience in the employee benefits and compensation field, on the structure of the FPUC Incentive Performance Plan (IPP) within the context of similar employee pay programs. I also will testify as to the type of compensation programs that are necessary in the labor market for companies to attract, motivate and retain highly skilled employee talent.

Q. ARE YOU FAMILIAR WITH THE FPUC INCENTIVE COMPENSATION PLAN?

A. Yes, I am. In 2013, I studied the Plan independently as part of PRM's review of Chesapeake Utilities Corporation's (CUC's) employee pay program. We benchmarked competitive base salaries for similar positions in similar size utilities and general industry.

We also reviewed the design of the Company's current IPPs, including the FPUC incentive plan. In addition, we collaborate with CUC in helping to gather their compensation data for participation in the main utility industry surveys as the American Gas Association.

Q. WHAT ELSE HAVE YOU REVIEWED IN THE PREPARATION OF YOUR TESTIMONY?

A. I reviewed the testimony of the Florida Office of Public Counsel's witness Donna Ramas as well as information regarding this issue as it relates to another Florida utility involved in a recent rate proceeding.

III. FPUC COMPENSATION

Q. ARE ANNUAL EMPLOYEE INCENTIVES COMMON WITHIN THE UTILITY INDUSTRY?

A. Yes. According to the AGA 2012 compensation survey, approximately 80% of the utility industry survey respondents provide all employees with some form of variable pay:

% of Organizations with Least one Plan	# of Reponses	Bonus	Current Cash Profit Sharing	Team/ Small Group Incentive	Individual Incentives	Spot or Technical Achievement Awards	Gain-sharing	Other Short-Term Incentives

Entire Sample Combined Executive	83.7%	49	95.1%	4.9%	7.3%	26.8%	24.4%	0.0%	0.0%
Management, Excluding Executives	81.6%	49	97.5%	2.5%	30.0%	52.5%	52.5%	0.0%	2.5%
Exempt, Non Management	83.7%	49	95.1%	4.9%	31.7%	56.1%	56.1%	0.0%	2.4%
Nonexempt	79.6%	49	87.2%	5.1%	30.8%	59.0%	59.0%	0.0%	2.6%

The AGA information is consistent with variable pay practices within general industry. Word At Work reported salary and variable pay practices on 2,124 companies throughout the United States. Specifically, the 2013-14 Salary Budget Survey reported the following results on national variable pay practices for various types of employees:

	Nonexempt Hourly Nonunion		Nonexempt Salaried		Exempt Salaried		Officers/Executives	
National	Mean	Median	Mean	Median	Mean	Median	Mean	Median
2012								
Average percent budgeted	5.4%	5.0%	3.3%	5.0%	12.6%	12.0%	37.3%	35.0%
Average percent paid	5.2%	4.0%	6.4%	5.0%	12.6%	11.0%	38.0%	32.0%
Percent of employees eligible in 2012 for variable pay	90%	100%	93%	100%	83%	100%	94%%	100%
2013								
Average percent budgeted	5.4%	5.0%	6.3%	5.0%	12.7%	12.0%	37.6%	35.0%
Projected percent paid	5.3%	5.0%	6.4%	5.0%	12.8%	11.0%	37.6%	33.0%
2014								
Projected percent budgeted	5.4%	5.0%	6.4%	5.0%	12.7%	12.0%	37.2%	35.0%

Q. WHAT COMMENTS DO YOU HAVE IN REFERENCE TO WITNESS RAMAS' TESTIMONY ON THE IPP AT PAGES 29-33, IF ANY?

A. I noted in witness Ramas' testimony that she did not question the use of incentive or variable pay as an integral component of total pay (i.e., base salary, plus other annual cash) delivery. In today's marketplace, most progressive organizations rely upon variable pay (or "at risk") as an efficient and integral component of their pay delivery systems. Witness Ramas' testimony focused on whether 100% of FPUC's IPP expense should be passed along to the Florida ratepayers. She concluded that only 55% of FPUC's IPP expense should be allocated to the ratepayers because of the corporate measures used in determining the annual IPP payout. However, she did not take into account the size of the IPP pool needed for FPUC to provide competitive pay in order to attract, motivate and retain talented employees. In other words, the IPP opportunity is an essential component of employee pay unless FPUC were to increase employee base salaries to offset the exclusion of variable pay provided to similar employees in other utilities.

Q. I TAKE IT THAT YOU DO NOT AGREE WITH WITNESS RAMAS' TESTIMONY TO ALLOW ONLY A PORTION OF FPUC'S IPP EXPENSE IN RATES. IF NOT, WHY NOT?

A. No. OPC's recommendation, if implemented, would have the effect of requiring shareholders to cover costs otherwise appropriately recovered through rates. As industry studies demonstrate, as well as past Commission decisions conclude, incentive compensation is consistent with industry practice and is an accepted part of competitive compensation packages used throughout the industry. Disallowing recovery for this component of the package would unfairly shift costs to shareholders. It also disregards the importance and benefit of this compensation component to the customer. This package helps achieve the Company's goal to provide the best quality service to customers while offering a competitive compensation package attractive to employees. A financially viable company that provides consistent quality service with professional dedicated employees is in the best interests of the customer.

Q. CAN YOU COMMENT ON THE MARKET COMPETITIVENESS OF FPUC'S CURRENT EMPLOYEE PAY PROGRAM?

A. Yes, I can.

Q. DO YOU THINK IT IS COMPETITIVE IN RELATION TO SIMILAR UTILITIES?

A. In my opinion, FPUC's current employee pay is competitive relative to market norms. My review of CUC's current actual employee pay indicates base salaries are consistent with those provided to similar employees in comparable utilities. Also, FPUC's total pay opportunities are competitive in relation to market norms.

Q. WHY IS THE UTILITY INDUSTRY AN APPROPRIATE COMPARISON?

A. When companies benchmark employee pay, they want to make sure there is an "apples to apples" comparison. To help ensure appropriate comparison, companies typically consider the following factors in market pricing:

— Type of industry (*i.e.*, gas and electric, regulated, non-regulated) with whom they are competing for talent); and

— Companies of comparable size (*i.e.*, revenues, market share, profitability).

Most companies perceive the labor market for employee talent to vary. For instance, the market pool for executives is considered to be a national pool, while the market pool for non-exempt employees would tend to be a more localized pool. However, the utility labor market for talent is a national market for certain skills and disciplines.

Therefore, in my opinion, utilities of comparable size represent the appropriate labor market for determining competitive employee pay for those positions commonly found within the utility industry. For other positions, companies typically survey both the general labor market and the utility industry to determine competitive employee pay.

Q. WHY IS THIS POINT RELEVANT TO FPUC'S SITUATION?

A. It is relevant because my research indicates the Commission has ruled favorably in the past in the recovery of incentive compensation in prior rate cases. As a general matter, the Commission has considered it appropriate to include "at-risk" compensation as a component of an employee's overall compensation package for purposes of determining whether the total compensation package is reasonable. For instance, in Docket No. 080317-EI, the Commission noted that ". . .lowering or eliminating the incentive compensation (for Tampa Electric) would mean Tampa Electric employees would be compensated below the employees of other companies, which would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce." Order No. PSC-09-0283-FOF-EI. The Commission, therefore, allowed recovery of incentive compensation expense.

Similarly, in the past, the Commission allowed recovery of similar incentive pay expenses for Florida Power Corporation (nka Duke Energy) and Gulf Power, in Dockets Nos. 910890-EI and 010949-EI, respectively. More recently, the Commission acknowledged that Gulf Power's incentive compensation plan included a goal of increased earnings per share for Southern Company, but affirmatively stated that it is appropriate to recognize that there is a benefit to ratepayers associated with a financially healthy company. Order No. PSC-12-0179-FOF-EI, page 95, issued in Docket No. 110138-EI. The Commission further stated that the OPC's recommendations in that case to remove all incentive-based compensation expense was unreasonable. *Id.*, at page 97. The Commission has consistently recognized that incentive, or at-risk, pay is an accepted and desirable way to simultaneously achieve corporate goals and control costs for the benefit of ratepayers.

Q. SHOULD THE COMMISSION REQUIRE A SHARING OF INCENTIVE COMPENSATION BETWEEN RATEPAYERS AND STOCKHOLDER(S) AS SUGGESTED BY WITNESS RAMAS?

A. No. The notion of cost sharing in the IPP ignores the fact that reasonable compensation cost is a fully recoverable rate expense. It is a necessary cost of providing service. A fundamental tenet of sound regulatory policy requires the Commission to allow the company an opportunity to earn its return on prudently incurred costs. For its part, the company must provide quality service to customers at just, fair, and reasonable rates. A basic principle of ratemaking is that all reasonable and prudent costs of doing business should be included in test year expenses. Unless the Commission finds specifically that the expenses in question are unreasonable or imprudently incurred, then these expenses should be allowed in calculating the appropriate revenue requirement. Assuming the Commission accepts this premise, then FPUC's IPP cost is an integral part of its employee pay and is in alignment with market norms within the utility industry. In other words, its total - base salary plus IPP - pay is reasonable relative to those provided similar utility industry employees. Therefore, FPUC should be permitted to recover 100% of its IPP cost in order to attract, retain and motivate talented employees to deliver quality customer service.

In implementation, OPC's recommendation would have the effect of requiring shareholders to cover costs otherwise appropriately recovered through rates. The net effect is to reduce investors' return on their investment even further than that recommended by OPC's witness Woolridge. This would significantly impact the Company's ability earn a fair rate of return, which ultimately would impair its ability to provide reliable service to its customers. Incentive compensation is consistent with industry practice and is an accepted part of competitive compensation packages used throughout the industry. Disallowing recovery for this component of the package would unfairly shift costs to shareholders, while also disregarding the importance of this compensation component to (1) helping achieve Company goals beneficial to ratepayers and (2) offering a competitive compensation package attractive to in-demand employees.

Q. HAVE YOU REVIEWED THE CUC CORPORATE BONUS PLAN?

A. Yes, I have reviewed the corporate bonus plan.

Q. BRIEFLY DESCRIBE THE STRUCTURE OF THE CORPORATE BONUS PLAN.

A. The corporate plan is similar to the design of the FPUC bonus plan. It consists of five eligibility levels based on position level, and the award opportunities at each level are set to provide competitive market median total cash (base salary plus target incentive award opportunities) for similar position levels within the utilities industry. Corporate awards are allocated to plan eligibles based on a combination of corporate earnings per share, corporate project, and department as well as individual goals and objectives which are weighted differently depending on eligibility level.

Q. SHOULD A PORTION OF THE CORPORATE BONUS OR INCENTIVE PLAN BE ALLOCATED TO FPUC?

A. Yes. It is typical market practice for organizations to allocate a portion of corporate employee compensation, including incentive pay, to its business units. Corporate employees help to direct and advise FPUC employees to help ensure quality customer service at reasonable prices. Without the corporate staff, FPUC would need to increase its employee population which would result in higher employee compensation costs/expenses to the rate payers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Q. **Please state your name, affiliation and business.**

A. My name is Matthew M. Kim. I serve as Vice President and Corporate Controller of Chesapeake Utilities Corporation ("Chesapeake"), which is the parent company of Florida Public Utilities Company ("FPU"). My business address is 909 Silver Lake Boulevard, Dover, Delaware.

Q. **Are you the same Matthew M. Kim who filed direct testimony in this proceeding?**

A. Yes.

Q. **Please state the purpose of your rebuttal testimony.**

A. The purpose of my testimony is to respond to the direct testimony of Donna Ramas filed on behalf of the Office of Public Counsel ("OPC") in this proceeding as it relates to certain aspects of the Company's compensation package, treatment of pension expense, corporate cost allocations, and our proposed tax "step-up" regulatory asset.

Q. Please summarize any exhibits that are included with your rebuttal testimony.

A. I have included the following exhibits with the rebuttal testimony:

MK-2 Presentation by Cook & Co to the Compensation Committee on executive compensation [CONFIDENTIAL]

MK-3 Pension Expense Projection

MK-4 Corporate Department Variance Reports

MK-5 Summary of Corporate Allocation included in AG

Q. Please summarize the key issues and areas that you will address in your rebuttal testimony.

A. I will provide rebuttal testimony to specifically address the issues raised by OPC witness Ramas in her direct testimony as follows:

* Stock Based Compensation Expense (Ramas, pages 23 – 25)
* Corporate Bonuses Allocated to FPUC Electric Operations (Ramas, pages 25 – 26)
* Pension Expense (Ramas, pages 33 – 36)
* Corporate Costs (Ramas, pages 55 – 69)
* Tax Step-Up Regulatory Asset and Amortization (Ramas, pages 74-75)

Stock-based compensation

Q. Do you agree with witness Ramas' recommendation at page 24 of her testimony to remove all of the costs associated with stock-based compensation included in the Company's projected test year expenses?

A. No, I do not agree with her recommendation. Jim Moss will provide additional discussions in his testimony on behalf of the Company regarding the appropriateness of including the stock-based compensation. In my rebuttal testimony, I would like to specifically address three points regarding Chesapeake's stock-based compensation plan, in response to witness Ramas' assertions.

The first point that should factor in to the Commission's consideration is the reasonableness of the total executive compensation package of the Company as compared to those offered by the Company's peers, as well as pertinent market data regarding executive compensation. Let me begin by explaining that Chesapeake provides stock-based compensation only to named executive officers, which is currently limited to the following five executives: Chesapeake's CEO/President and three Senior Vice Presidents, and the President of FPU.

As also noted in the testimony of witness Moss, stock-based compensation cannot be considered in a vacuum. To the contrary, the level of the total compensation package for these executives must be considered when assessing the reasonable and prudent level of expenses, which is precisely the approach taken by the

Compensation Committee of Chesapeake's Board of the Directors. The Compensation Committee engaged Frederic W. Cook & Co., Inc. ("Cook & Co."), an independent consulting firm, to assist in the evaluation of executive compensation at the end of 2013. Cook & Co. conducted a market analysis to assess the competitiveness of compensation offered to Chesapeake's executive officers, compared to executive compensation in the energy industry and of the Company's comparable peer group. In its assessment, Cook & Co. considered "Total Direct Compensation," which includes base salary, short-term bonuses and long-term incentive (i.e., stock-based compensation). Cook & Co. advised the Compensation Committee that Chesapeake's target total direct compensation offered to its executive officers is competitive with both the energy industry and its peer group. A copy of the presentation by Cook & Co. to the Compensation Committee is provided in Exhibit – MK-2 [CONFIDENTIAL]. The same presentation was previously provided in conjunction with the Company's response to Staff's First Request for Production of Documents No. 9.

The second point I would like to address is the manner in which the three performance components of the stock-based compensation align with the interests of each of Chesapeake's businesses, including the FPU electric division. With no readily apparent analysis, witness Ramas concluded at page 24, line 18 that "[t]he components in determining the stock-based compensation awards are clearly focused on CUC's shareholders… [c]learly, the goals are not focused on benefitting Florida

Public Utility's electric ratepayers." While she does not explicitly state that she believes the interests of shareholders and ratepayers cannot be aligned, this seems to be the conclusion drawn by witness Ramas. Since she did not elaborate on her reasons, it is difficult to provide a point-by-point rebuttal, but I certainly disagree with her conclusion. The strong financial performance of the Company is ultimately good for both shareholders and ratepayers, because it positively affects the rates charged to ratepayers, as well as growth within the service territory and also results in increasing values to shareholders. The notion that improving shareholder value is contrary to the benefit to ratepayers, as witness Ramas seems to indicate, is simply wrong. Chesapeake's performance components are designed to provide value to all stakeholders, including shareholders and ratepayers. In fact, the majority of Chesapeake's businesses are regulated utilities. As such, Chesapeake fully understands the importance of managing both investments and returns. We recognize that when we make profitable investments that generate desired returns, our utility ratepayers benefit from better service, as well as expanded service, and our utilities are able to avoid - or at least defer - the need to increase rates.

Q. Is it contrary to regulatory policy to provide benefits to shareholders?

A. Not at all. Regulatory policy and law in Florida, as well as other states in which we operate, recognizes that utility investors should be allowed to earn a reasonable rate of return on their investment. Shareholders benefit from the value generated from the Company's strong financial performance and are encouraged to further invest in the Company as a result of our good track-record for managing our capital investments. The growth in long-term earnings and earnings performance components of Chesapeake's stock-based compensation program are specifically designed to encourage such behaviors. The growth in the long-term earnings component is measured by comparing Chesapeake's level of total capital expenditures, as a percentage of the Company's total capitalization, to that of the Company's peer group. This performance component is designed to encourage Chesapeake's executives to identify capital investment opportunities at a rate higher than that of the Company's peer group. This component may actually lower the dividend paid to the Company's shareholders, compared to that of its peers, as more cash from its earnings may need to be retained to finance the higher rate of capital investment. Chesapeake nonetheless believes in the importance of growing and expanding its services, and this approach to compensation allows the Company to grow without relying solely on rate relief.

Q. Does earnings performance also factor into the value of the long-term incentive compensation component?

A. Yes, it does. The earnings performance component is based on return on equity (ROE). For regulated utilities, making investments that can generate a desired level of return is paramount to the utility's ability to sustain its earnings and avoid a constant cycle of seeking rate relief. Investing in growth, while maintaining a reasonable level of ROE, is the only way to ensure sustainable, long-term financial health and business growth, which again benefits both ratepayers and shareholders. As Chesapeake and its affiliated utilities, including FPU's electric division, strive to achieve these financial and growth objectives, we have been able to defer rate cases as a result of our successful management of each utility's rate base and returns. Although the FPU electric division is requesting a rate increase in this proceeding, it should be noted that the Company avoided making such a request for approximately 7 years, in spite of its under-earning, which is longer period than that of its peer electric utilities in Florida. It should also be noted here that Chesapeake only acquired FPU in 2009; thus, some time has necessarily been spent working to revive the Company's financial and operational straits. Providing executive incentives to manage rate base and returns is effective in mitigating rate case expense and increased rates to the consumer. This is most effectively done through the stock-compensation plan provided to these executives.

Q. Is there another component that makes a long-term incentive plan meaningful for a utility?

A. Yes. The third performance component – shareholder returns – is a reflection of earnings performance, sound capitalization policy, and reputation in the market place. In order to generate earnings, a utility has to manage its costs, as well as manage its investments and returns. Managing costs is also beneficial for the Company's rate payers, because it ensures that the Company has the proper cost structure and is making investments in a prudent and reasonable manner. Sound capitalization policy ensures a strong balance sheet, which, in turn, allows a utility to access capital at attractive rates and terms. Likewise, reputation of a utility, as with any business, is based on customer satisfaction, employee engagement, trust in management, and the ability to execute business and financial strategies. These factors are also important to utility ratepayers in that they impact service quality, the viability of the business, and ultimately, rates. As such, there is a clear alignment of both ratepayer and shareholder benefits with regard to each of the performance components of our long-term incentive compensation plan. Key Company executives are incentivized to achieve each of the three performance components, which, if achieved, directly benefit the Company's ratepayers.

Q. Do you agree with witness Ramas' suggestion at page 24 that stock-based compensation expense should be removed from the projected test year because it focuses on improving stockholder value through investing in regulated and non-regulated business?

A. No. The executives' stock-based compensation is subject to allocation to the FPU electric operation based on the specific level of service received by the electric division. Witness Ramas mentioned that the performance components "are based on regulated and unregulated businesses" and used this as part of her reason for excluding the entire cost associated with stock-based compensation in the Company's projected test year expenses. It appears, based on her conclusions, that witness Ramas did not consider the fact that these costs are allocated and only the portion representing the benefit of those executives' service to the FPU electric division is reflected in the Company's projected test year expenses. Specifically, for three of the named executive officers who receive the stock-based compensation, the expense associated with their stock-based compensation cost is allocated across all of Chesapeake's businesses in the amounts attributable to each business unit. As for the President of FPU, his stock-based compensation cost is allocated to all of the Florida business units under his management, which is as it should be. Given the appropriate allocation of these costs, I disagree with witness Ramas regarding exclusion of stock-based compensation cost from the projected test year.

<u>Corporate bonus</u>

Q. Do you agree with witness Ramas' recommendation to remove all of the allocated corporate bonus expense?

A. No, I do not agree with her recommendation. Similar to the executive stock-based compensation and FPU's IPP expense, the corporate bonus component of our total compensation package is provided to corporate employees, who provide valuable services to the various business units, including the FPU electric operation and its ratepayers. It is a compensation component consistent with industry practice, the inclusion of which ensures that our compensation package is consistent with industry and peer group levels, and therefore, competitive. As such, it should be considered a prudent and reasonable cost. Witness Moss will provide additional discussions regarding the appropriateness of including this expense in the projected test year in his rebuttal testimony.

Q. Given witness Ramas' statement at page 25 that no information on the corporate bonus plan was provided, would you please describe the plan?

A. Corporate, non-officer-employees are subject to an incentive performance plan ("IPP"), similar to each of Chesapeake's businesses including FPU. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

As noted, and also as further emphasized later in my testimony, the corporate departments contribute to the overall financial performance of each of Chesapeake's businesses by providing efficient and cost-effective services that are critical to the day-to-day functions of the business units, including the FPU electric division. The corporate departments help our business units identify, assess and analyze various opportunities to generate growth, manage projects, expand service offerings, improve customer communications, and identify strategic opportunities. As I discussed above, growing revenue and managing costs, while also accessing capital markets to obtain capital at attractive rates and terms, are essential components of achieving higher EPS, which benefits both ratepayers and shareholders. To be clear here, Corporate EPS is an accumulation of earnings of each of Chesapeake's businesses, including the FPU electric division.

Finally, on this issue, I want to emphasize that the costs of each department, including bonus expense, are allocated to all Chesapeake businesses that receive benefits from that department's service. Allocation factors are designed to closely mirror the level of service of each department to each business. Thus, the FPU electric division would be assigned minimal or zero costs associated with a department that provides little or no benefit to the FPU electric division.

Pension

Q. Do you agree with witness Ramas' recommendation at page 35, line 6, to use the most recent actuarial projections for the projected test year expense?

A. No, I do not. In my opinion, witness Ramas did not demonstrate that the use of the 2014 expense projection, which is based on assumptions set at a point-in-time, provides a better projection given a significant volatility in discount rates. FPU's pension expense has fluctuated significantly over the past five years, due primarily to volatility in discount rates affecting both the projected pension obligation and the amount of contributions required to be made into the plan. In an environment with steady discount rates, the use of the most recent actuarial projection may be sufficient as the pension expense is generally not expected to fluctuate significantly year-over-year. However, given FPU's recent experience with a significant fluctuation in its pension expense, simply utilizing the most recent actuarial projection, which again is based on assumptions and projections at a single point-in-time, cannot provide an accurate estimate of the expense in the projected test year. The same schedule provided in OPC POD No. 15, which shows the 2014 pension expense projection referred to by witness Ramas in her testimony and is attached to my testimony as Exhibit MK - 3, also shows the volatility in expense based on even a slight change in assumptions. A 0.25 percent decrease in both discount rate and long-term return on assets would have caused the 2014 pension expense projection to increase by $107,133 for the entire FPU plan. As such, $31,069, or a 29 percent of the increase, would be allocated to FPU electric operation.

Q. What has been the trend in the market since the selection of actuarial assumptions used in the 2014 pension expense projection?

A. As witness Ramas correctly stated, FPU was required to select, at the end of 2013, the assumptions regarding discount rate and long-term return on assets for the 2014 expense projection. Since the assumption on return on assets considers long-term investment and market trends, it typically does not change significantly. However, there has been a significant decline in the Treasury rates and bond yields during the first half of 2014. The yield on the triple-B (Bbb) rated Treasury securities declined from 5.35 percent at the end of 2013 to 4.76 percent. Citigroup Pension Liability Index, which is one of the bond indices widely used to compare pension discount rates, declined from 4.95 percent to 4.33 percent. Both Treasury rates and bond yield curves are the information used to form the discount rate assumption for FPU's pension plan. Such volatility is consistent with the market trend experienced in the past several years. For example, in 2013, Citigroup Pension Liability Index moved from 4.30 percent at the beginning of the year to as low as 4.07 percent in April before increasing all the way to 4.95 percent at the end of the year. This type of severe volatility is making it extremely challenging for the Company to project its pension expense over a long period of time based on assumptions set at a single point-in-time.

Q. Why does the Company believe the use of the four-year average is a better way to project the pension expense in the projected test year?

A. The Company used the four-year average, because it would smooth the "ups-and-downs" of FPU's pension expense. The four-year period corresponds to the period since FPU made certain changes to its pension plan and froze it in conjunction with its merger with Chesapeake back in 2009. By averaging FPU's pension expenses during those four years (from 2010 to 2013), the projected pension expense, excluding the amortization of a pension regulatory asset resulting from the 2009 merger, is *de minimis* ($6,235 for FPU electric), which further supports the smoothing of pension expense.

<u>Corporate costs</u>

Q. Do you agree with witness Ramas' suggestion, at page 56, line 3, that the Company's requested corporate allocations included in the projected test year expenses are "excessive"?

A. No, I do not agree with the suggestion. Before specifically addressing the corporate costs allocated to FPU electric operation in the projected test year, I would like to first look at the overall Administrative and General ("A&G") expenses of the Company in the projected test year. Since almost all of the corporate allocation is to A&G accounts, by looking at the overall level of A&G expenses, I can discuss the appropriateness of the level of A&G support in the Florida electric operation without regard to where the cost is expected to originate. One of the simplest ways to assess the appropriateness of the Company's overall level of A&G expenses is to compare it to other electric utilities in Florida on a per-customer basis. The Company's A&G expenses allocated both from the business unit and corporate and included in the projected test year total $5,537,203. The customer base across which these costs would be spread is projected to be an average number of 31,320 customers. That equates to A&G expense of $176.80 per customer. Based on the information provided in FERC Form No. 1: the Annual Report of Major Electric Utilities, Licensees and Others for the year ended December 31, 2013, A&G expense per customer by other electric utilities in Florida is as follows: $208.90 for Tampa Electric Company, $183.00 for Gulf Power, $166.21 for Duke Energy Florida and $87.98 for FP&L. Despite FPU's significantly smaller size and a projected increase in A&G expenses, FPU's level of A&G expenses per customer is clearly comparable to that of its peer utilities, and in some cases, more favorable. Given the reasonableness of the overall A&G expenses based on the per-customer comparison, witness Ramas' conclusion regarding the level of the corporate allocation included in the projected test is baseless and without any merit.

In the past two years, the Company has experienced an increase in its A&G expenses and projects that this trend will continue for the next two years. This trend is a direct result of the Company's effort to strengthen A&G functions for all business units, particularly through additional support and engagement from Chesapeake's corporate team. As it relates to FPU, prior to the merger with Chesapeake, FPU invested the bare minimum in A&G functions like IT, HR, communications, system development, business development and management oversight. This lack of adequate investment in these areas is evidenced by FPU's significantly lower level of A&G expense per customer in those years than its peers. In 2010, which was the first full year after the merger, the Company's A&G expense per customer was $129.98, far below the level of per-customer A&G spending by Tampa Electric Company, Gulf Power and Duke Energy, which ranged from $166.04 to $194.65.

Realizing the importance of A&G functions to adequate support its business, the Company has increasingly relied on Chesapeake's corporate resources and capabilities to improve those functions. Later in my rebuttal testimony, I will provide more details on the benefits to FPU's electric ratepayers resulting from the increased support by specific corporate departments mentioned in witness Ramas' testimony and consistent with my Direct Testimony at pages 14 through 16.

Q. Given witness Ramas' suggestion at page 59, line 22 that Chesapeake's corporate expenses have consistently been below the budget amount, how accurate has the budget for Chesapeake's corporate costs been in the past?

A. Witness Ramas stated that the total corporate expenses, as well as the expenses charged to FPU's electric operation, have consistently been below the budgeted amounts. She provided the numeric illustration of such variance in her testimony. While her figures are factually accurate, this illustration does not provide the complete picture of the accuracy of the budget for those years, nor does it adequately address the accuracy of the budget used in the projected test year. In looking at the variance in detail, and using the same information in the Company's response to OPC POD No. 52, at FPU RC-5428 (included herein as Exhibit MK-4), as witness Ramas did in her testimony, a large portion of the variance between the actual cost and budgeted cost for those two years (2012 and 2013) was attributable to post-retirement benefit expense and a delay in starting new departments. Here is the revised illustration, which takes these inputs into account.

2012	**Total**	**Allocated to FPU EL**
Budget to actual variance	$1,006,816	$ 207,247
Postretirement benefit cost variance (HR902 and HR942)	$ 335,478	$ 29,592
Delay in starting new departments (SP900)	$ 281,606	$ 21,788
Net variance	$ 389,732	$ 51,380
Net variance as % of budget	1.6%	6.4%
2013	**Total**	**Allocated to FPU EL**
Budget to actual variance	$1,763,260	$164,762

Postretirement benefit cost variance (HR902 and HR942)	$ 423,520	$110,010
Delay in starting new departments (NE980)	$ 575,085	$ 38,145
Net variance	$ 764,655	$ 51,380
Net variance as % of budget	2.7%	0.6%

The variance in post-retirement benefit expense (department codes HR902 and HR942) is due to: (1) volatility in actuarial assumptions (mainly discount rates) between the budget and the actual, which changed the expense; and (2) a one-time benefit change in FPU's benefit that was not incorporated in the budget. As explained in the Company's response to OPC Interrogatory No. 88(e), the Company revised the expense projection for post-retirement benefit cost in Account 925 included in the projected year A&G expense and did not use the amount per the corporate budget. Therefore, this does not have any impact on the Company's projected test year expense.

The variance in new departments (department codes SP900 and NE980) is due to a delay in the timing of starting those departments. Chesapeake budgeted the Strategic Development Department (SP900) in 2012 and New Energy Development Department (NE980) in 2013 to commence at the beginning of each year, respectively. The start of those departments was delayed as a result of the longer-than-expected recruiting and training/orientation process to get the necessary talent with the appropriate skill sets. Chesapeake's corporate budget used in the Company's projected test year expenses does not include any new department.

Therefore, it is not a recurring issue for which an adjustment would otherwise be appropriate.

There is a minor discrepancy in the level of variance between the overall corporate costs and the amount allocated to FPU electric operation. The reason for such discrepancy is the allocation changes. Chesapeake estimates the allocation factors for the upcoming year during the budget process, which is further updated at the beginning of each calendar year with actual amounts. In the Company's response to OPC Interrogatory No. 129, the Company provided the impact of such allocation change by comparing the 2014 budget allocation factors used in the allocation of corporate costs in the projected test year and the 2014 actual allocation factors (the most recent update). The difference is an increase in allocated costs by $41,141, or 1.3 percent. Because it was an increase, the Company decided not to update the projected test year expense to reflect this change.

Therefore, Chesapeake's corporate budget and the portion of the budget allocated to FPU electric operation in the past two years, adjusted for the referenced variance factors, have been accurate to the extent reasonably possible. Again, the variance factors impacting the budget had no impact on the accuracy of the budgeted costs used in the Company's projected test year.

Q. Why did the Company use Chesapeake's budget to determine the corporate costs allocated to FPU electric in the projected test year?

A. Projecting A&G expenses allocated from Chesapeake's corporate team based on escalation, as well as known and measurable changes, is challenging given the allocated nature of such costs. This requires the Company to project the overall changes to the entire cost of Chesapeake's corporate team, as well as any measurable changes to allocation factors used for each corporate department. Each of Chesapeake's corporate departments prepare detailed, "bottom-up" budgets that incorporate specific changes to the levels of staffing, benefits, and expenses associated with outside services, normalizing items, and allocations. As such, the amount of corporate costs expected to be allocated to FPU's electric operation was already prepared in the budget process and any variance from previous accounting periods can be identified and measured. As previously indicated in my rebuttal testimony, Chesapeake's corporate budget has been accurate, except for some fluctuation associated with actuarial assumptions used in post-retirement benefit costs and the timing of new departments. Neither of these anomalies had any impact in projecting expenses for the Company's projected test year.

Q. Why does the Company believe the budgeted corporate costs are a better reflection of the projected test year expenses than the historic test year amount with escalation applied, as suggested by witness Ramas?

A. Witness Ramas recommended at page 61, lines 10 – 12, that the level of corporate cost allocations included in the Company's projected test year expenses should be "limited to the historic year amount with escalation applied." That approach does not incorporate the known and measurable adjustments, and therefore, it is not consistent with the Commission's past practice in assessing the prudent and reasonable costs. The Company responded to numerous requests from the Office of Public Counsel to provide explanations for the increased expenses allocated from the corporate team, most of which witness Ramas decided not to discuss in her testimony. Other than stating that Chesapeake's corporate costs have historically been below the budgeted amount, which I have addressed earlier in my rebuttal testimony, witness Ramas did not provide any details or explanations to justify her recommendation. She also mentioned three specific departments with an increase in costs as examples, IT, HR and Communications, with no further elaboration on the reasonableness of those increases. I will address each of those departments in greater detail later in my rebuttal testimony. I would like to first provide the most recent data on the expenses allocated from the corporate team, using the similar format provided by witness Ramas.

	Payroll Expense	Non-payroll Expense	Total Expense
Projected Test Year Adjusted	$968,454	$1,974,242	$2,942,696
12 Months Ended June 2014	$889,474	$1,687,148	$2,576,621
Historic Test Year Adjusted	$779,551	$1,641,846	$2,421,397
Increase from Historic to			
Projected Test Year	$188,903	$332,396	$521,299
	24.2%	20.2%	21.5%
Increase from 12ME June 2014			
to Projected Test Year	$78,980	$251,644	$330,624

8.9%	14.6%	12.7%

Similar to the way Ms. Ramas presented the data in her testimony, I excluded the $120,000 associated with the general liability recovery included in the corporate allocated A&G expenses in the projected test year. This exclusion is for illustration purposes only, as the discussion involving the general liability reserve is addressed in the rebuttal testimony of Cheryl Martin. This illustration should not be taken as a suggestion that this amount should be excluded from the Company's expenses.

The most recent data (12 months ended June 2014) shows that expenses allocated from corporate departments have already exceeded the historic test year amount. This increase was expected, because the Company is focused on strengthening its A&G functions, and this increase is reflected in the projected test year amount. Simply ignoring the increase, as well as prudently incurred additional increases that occur in the future, is not consistent with the Commission's policy of reviewing the actual expenses and projected expenses in order to determine both their prudency and the customer benefits derived from those expenses. Allowing only the historic test year amount plus escalation would entirely bypass the review process in favor of less reliable trending that fails entirely to take into account changed circumstances. Again, this is not consistent with the Commission's past practice.

Exhibit MK-5 to my rebuttal testimony further breaks down the increase in the corporate cost allocation from the historic test year to projected test year. The increase can be summarized in the following way:

Historic test year corporate cost allocated	$2,421,397
Escalation applied to historic test year	137,031
Increases experienced as of June 2014	155,224
Additional increases projected	229,044
Projected test year corporate cost allocated	$2,942,696

Q. Please further elaborate on the factors contributing to this increase and how the Company's ratepayers benefit from this increase.

A. Since witness Ramas mentioned the IT, HR and Communications departments in her testimony as examples of the increase, let me start with those departments. The IT department costs include costs associated with IT support staff, maintenance of financial, HR, billing and other customer service applications and telephone systems, networks and desktops and overall IT security. All IT functions are performed by the Corporate staff for the sake of efficiency and also to ensure consistency across the Chesapeake business platform. The IT department costs allocated to FPU electric in the historic year were $483,123. During the 12 months ended June 2014, those costs increased to $538,405. The amount included in the Company's projected test year is $637,204. The two primary reasons for the increases are the increased level of IT staffing and the increased cost associated with supporting and maintaining systems, networks and desktops. Since the beginning of the historic test year, the IT department added five people to further strengthen its help desk, system administrator, and business analyst functions. Chesapeake also plans to recruit 10 additional employees to increase its help desk functions in order to better resolve day-to-day IT-related problems and concerns from employees, to enhance its business analyst capabilities for purposes of , more effectively obtaining financial and operational data for our business units, and to increase its system administrative support staff to manage day-to-day IT infrastructure maintenance.

Also included in this increase are costs associated with enhancing Chesapeake's cyber-security. Subsequent to the historic test year, Chesapeake has engaged external consultants to assist in its ongoing efforts to identify and resolve cyber security concerns. The long-term plan is to hire an in-house resource to manage cyber security internally, in lieu of continuing to involve external consultants, for which the projected test year reflects an additional headcount. Cyber security is a key in our Corporate strategy for all affiliates because breaches to security can have devastating impacts for both utilities and customers. The Company strives, however, to implement appropriate security measures in a cost-effective way. As noted just last year in a Report issued by the National Association of Regulatory Utility Commissioners, which was also backed by the U.S. Department of Energy:

> Cybersecurity threats challenge the reliability, resiliency and safety of the electric grid, and utility spending to address cyber vulnerabilities can impact the bills that customers pay.[1]

and

> Malicious attacks threaten utilities on multiple levels in ways that sometimes overlap and compound each other. It may be helpful to

[1] Cybersecurity for Regulators 2.0 (NARUC, February 2013) at page 3.

visualize the application of cybersecurity in three areas: IT, supervisory control and data acquisition (SCADA) systems, and smart grid.[2]

Overall, the higher costs associated with system, network and desktop maintenance and support reflects the increased demand for more complex IT systems and infrastructure. It also reflects the increased amount of, and use of, IT equipment.

Further strengthening IT infrastructure and ensuring security of the Company's IT environment has a clear benefit to the Company's ratepayers. They benefit directly from improvements in our IT department through enhanced interaction with the Company via our web site and call center, both of which have gone through significant improvement in recent years and are supported by the IT department. The Company is also currently involved in the implementation of a major billing system upgrade to further enhance its access to customer records and overall billing and customer service process. The IT department supports this project by ensuring additional network and system capacity, as well as a safe and secure IT environment to operate. The ratepayers also indirectly benefit from a reduction in costs, or in some cases the absence of increased cost, as a result of implementing various technology tools and enhancing connectivity among employees. For example, the costs associated with the Finance function are projected to decrease by $61,449 from now to the projected test year as it plans to further consolidate its function and

[2] *Id.* at page 6.

eliminate duplication. Without proper connectivity between the Operations and Corporate team through improved IT infrastructure, such reductions in cost would not be possible. Even at the business unit operational level, the Company is able to enhance its productivity and eliminate duplication as a result of more advanced IT support and infrastructure. The opening of FPU's new office in Fernandina Beach is another example of this. It is another benefit to the community overall, as well as ratepayers, and without the proper support in IT infrastructure, it would not have been possible.

The HR department costs allocated to FPU electric in the historic year were $192,560. During the 12 months ended June 2014, it has already increased to $223,463. The increase is due to the additional costs associated with improved and enhanced recruiting. Specifically, Chesapeake has adopted the "Top-Grading" interviewing and screening process, and is consequently revising its policies and procedures related to various employee benefits and conducts. Although the HR department has added, and plans to add, more resources to handle the increased demand for recruiting efforts and compensation assessments, the efficiency derived from re-assigning existing staff and combining certain functions has allowed this department to avoid increasing its payroll-related expenses allocated to the Company. The amount of the HR allocation included in the Company's projected test year increases to $243,323, due primarily to the escalation factor applied and additional costs related to the employee recognition and appreciation programs.

Payroll and benefits costs are one of the most significant costs of the Company. Recruiting and retaining talented workforce is crucial to fulfilling the ultimate goals of providing high-quality service and maintaining a competitive cost structure. The HR department has implemented various initiatives to ensure a high level of employee satisfaction and to strengthen employee recruiting and retention efforts. As a result, Chesapeake has been named one of the Top Workplaces in consecutive years, which evidences our improved ability to recruit and retain talented workforce to serve our customers. Even the wellness initiatives implemented by the HR department have a positive impact by reducing injuries and healthcare costs. The Company's ratepayers benefit from all of these efforts by receiving high-quality service at a competitive price.

The Communications department costs allocated to FPU electric in the historic year were $101,593. During the 12 months ended June 2014, the amount increased to $116,468. The amount included in the Company's projected test year is $141,712. The largest factor affecting this increase is higher payroll and benefits as a result of increased headcount. The Communications department added a communications specialist during the historic test year and a director for the department in early 2014. The department is also planning to add another communications specialist during 2014. These recent and expected additions to this department are necessary as a result of increased corporate-wide initiatives, such as the Service Excellence initiative, web site initiative and Top Work Place initiative, all of which are designed to increase the level of customer service and to improve the customer experience through better communications, high employee satisfaction, and consistency and excellence in our business conducts. The increased resources also address the increased investor communications through the Annual Report and Proxy statements which are necessary to meet increased information requirements.

Customer service and customer engagement are two of the top priorities of Chesapeake and the Company, as we strive to deliver high-quality service to customers. The Communications department assists the Company in developing and maintaining content on its web site with added customer-centric functionalities. It also works with the Company to initiate and further implement a Service Excellence initiative, which focuses on continuous review and improvement of service to customers. The Service Excellence initiative maps the Company's processes, critically reviews its systems and evaluates its method through the "lens of the customers" to ensure we are delivering a high level of customer satisfaction. As further described in the testimony of Mr. Householder, the Company has developed four service standards – safety first, the "Wow!" factor, presentation, and results orientation – which guide the Company's customer contact processes and measure the success. This Chesapeake-wide service satisfaction initiative, with the help of the Communications department, has already proven to provide direct benefits to the Company's ratepayers. In addition, the increased and enhanced investor communications also benefit the Company's ratepayers as a result of Chesapeake's enhanced ability to attract competitively-priced capital.

Q. Do you agree with witness Ramas' statement at page 63 that the Company included non-utility costs allocated from Chesapeake in the historic and projected expenses?

A. No, I do not agree with this. In her testimony, witness Ramas stated that the activities of some of the corporate departments "do not appear to be related to the function of the FPUC electric operations." Witness Ramas specifically recommended the exclusion of the costs from the Senior Vice President ("SVP") of Strategic Development, the Strategic Development department and the New Energy Development department. Before I address each of these departments, I would like to point out that the cost associated with the Strategic Development department is <u>not</u> included in A&G expenses, because the department assists the Company in electric supply and system planning activities, system mapping and supply market analysis. Since such activities represent operation supervision and engineering expense rather than A&G expense, it is reflected in Account 580 in the Company's adjusted historic test year and projected test year amount.

<u>SVP - Strategic Development</u>

The SVP of Strategic Development, discussed at page 65 of witness Ramas' testimony, is one of the senior executive positions at Chesapeake overseeing the areas of Human Resources, Communications, Strategic and New Energy Developments and Governmental Relations. This executive directly supervises corporate departments related to these areas and also coordinates with all of Chesapeake's business units regarding efforts related to these departments. Throughout my rebuttal testimony, I have discussed services provided by the corporate departments in these areas to the Company and associated benefits to the Company's ratepayers. This executive works with each business unit, including FPU's electric division, to develop a long-term strategic plan by identifying business opportunities within their existing service footprint, as well as addressing market risks and threats by proactively engaging necessary resources to formulate a plan and engages these departments, as appropriate, to advance the strategic plan's objectives. One of the specific examples involving FPU's electric division is [redacted] This is a project that was developed during the annual strategic planning process, which is headed by this executive. The Strategic Development team, under the supervision of this executive, has been working with the System Planning group at the business unit to analyze various market, financial and operational data. This executive also brings significant experience with regulated utilities and customer service, having previously served as the head of a FERC-regulated utility and director of customer service at the same utility.

Other than asserting, at page 65, line 20, that the costs associated with HR included in this department for the projected test year would be "incremental to the HR costs already charged to FPUC electric operations from a separate CUC HR Department," witness Ramas provides no other explanation for her claim at lines 21 - 24 that "[t]he Company has not demonstrated that the existing FPUC electric ratepayers benefit from this department, or that the department is focused on the existing regulated electric operations." Given the specific examples of the SVP's involvement in the FPU electric operation and her general responsibilities overseeing various corporate departments providing necessary services to the FPU electric operation, I disagree with witness Ramas' statement.

The SVP of Strategic Development department costs allocated to FPU electric in the historic year were $111,691. During the 12 months ended June 2014, the amount decreased to $71,362 due to [redacted] The amount included in the Company's projected test year is $153,873. As witness Ramas stated in her testimony, one of the factors contributing to the increase from the historic year to projected test year is the additional cost associated with the Vice-President of HR, which is budgeted in this department, rather than in the HR department. The Vice-President of HR was hired during the first quarter of 2014. Another reason for the additional projected cost is the anticipated hiring of a director of governmental relations, for which efforts are under-way to recruit this position. The new hire in this position will coordinate various governmental policy and relationship matters.

Strategic Development Department

As for witness Ramas' concerns raised, starting at page 66, regarding the Strategic Development department itself, this department is relatively new, having been created in 2012. The purpose of this department is to facilitate Chesapeake's annual strategic planning process, coordinate with the business units regarding strategic business development opportunities, and assist business units in various energy-related market research, analysis and system planning. Specific examples of the services provided by this department to the FPU electric division include [redacted] as previously described, assistance with the GIS/mapping system, and providing project management coordination. The Strategic Development department works closely with FPU's System Planning group to supplement its knowledge and capabilities by providing these resources and skill sets. This avoids FPU having to develop its own division-specific resources to handle non-routine, strategic initiatives. These initiatives and tasks are designed to manage the costs of the Company's services charged to ratepayers through: (1) developing a plan to lower fuel costs; (2) combining efforts in utility system planning areas to promote consistency, standardization, greater efficiency, and lower costs; and (3) providing assistance on project management coordination for large, complex initiatives that would otherwise be very difficult for the relatively small electric division to handle in-house. Based upon the type of services provided by the department to the FPU electric operation and benefits to its ratepayers associated with those services, the costs allocated from this department should be included in the Company's historic and projected test year amounts.

The Strategic Development department costs allocated to FPU electric in the historic year were $35,510. As noted in witness Ramas' testimony, the historic year amount did not include a full year of allocated costs since the department was first established in 2012. During the 12 months ended June 2014, the amount increased to $72,088 and the amount included in the Company's projected test year is $115,848. Because this is still a relatively new department, it is still in the process of recruiting resources to complete the department. It currently projects to add two additional resources, specifically to assist in project management of large strategic initiatives and GIS/mapping system maintenance.

<u>New Energy Development Department</u>

The New Energy Development department is also a new department created in 2013. As witness Ramas correctly noted at page 64 of her testimony, the purpose of this department is to support various corporate and business unit efforts to identify, evaluate, and assess new business initiatives in the energy industry that can complement our existing business strategies. This department also provides various skill sets, such as market trends analysis/intelligence, financial modeling, energy supply analysis, and other related business development analysis. Chesapeake's business units, including the FPU electric operation, utilize these services. Identifying new business initiatives benefits all of Chesapeake's businesses, including FPU's electric division, as it provides an opportunity to lower the allocated support and overhead costs by sharing various A&G type of functions. Corporate cost is one such example. Specifically, market trending and related intelligence, including electric supply analysis, benefits the FPU electric operation in that it develops and assesses strategies for providing the most cost effective and reliable service to Company customers. Such information can also help the FPU electric division to develop a business plan to expand or complement its existing electric service by operating small electric distribution systems owned by municipalities. Developing such plans and strategies requires specific skill sets and resources, the cost of which would be difficult for the FPU electric operation alone to manage. By sharing this capability from the Corporate resources, the FPU electric operation can share some of this cost while retaining the benefits of these services. The Company's ratepayers benefit from future savings in A&G costs.

The New Energy Development department costs allocated to FPU electric in the historic year A&G expense were $82,229. The amount included in the Company's projected test year A&G expense is $178,989. The increase is due primarily to the fact that the historic year and the 12 months ended June 2014 did not include a full-year impact of this department.

Q. Do you agree with witness Ramas' recommendation at page 62 of her testimony regarding non-recurring costs?

A. Witness Ramas discussed the consulting expenses related to two former FPU executives during the historic test year as non-recurring costs. These expenses are not included the projected test year amount, because the subject consulting agreements expired in early 2014 without renewal. These services have been absorbed by Chesapeake's existing management, Strategic Development, and Finance teams, so that the FPU electric operation receives the same level of service without the services of these two former executives. Again, these costs were not included in the projected test year; therefore, witness Ramas' recommendation to remove them would simply be incorrect.

Tax Step-up

Q. Do you agree with witness Ramas' recommendation to reject the Company's proposed tax step-up regulatory asset and the amortization thereof?

A. No, I do not because rejecting the Company's proposals on this issue would result in a violation of the tax normalization rule with which FPU is required adhere in order to continue to utilize the accelerated depreciation deduction for tax purposes. I will elaborate further on the normalization rule later in my rebuttal testimony. I also disagree with witness Ramas' statement at page 74, line 23, that "[t]here is no basis for FPUC to now request a regulatory asset associated with the initial step-up for the ADIT balance from ratepayers more than four years after the acquisition by CUC took place." A utility generally cannot (and certainly not in Florida) establish a regulatory asset without approval from the regulators or clear precedent. FPU is simply following a regulatory process by waiting to establish this regulatory asset until the matter is presented to the Commission for approval. Since there had not been a rate proceeding involving FPU electric operation after the merger (when the initial step-up occurred), this is the first opportunity for FPU to present this regulatory asset and the amortization thereof and incorporate the impact into base rate for the Commission approval.

Q. How did the Company record the initial step-up of the ADIT balance?

A. Since FPU could not establish a regulatory asset without proper approval, the step-up of the ADIT balance and the corresponding debits were both recorded in Account 282.2 for regulatory purposes. FPU used a different "natural account," which is the account code sequence used for the US GAAP reporting, to differentiate the credit side of the adjustment ("natural account" 2500, which indicates ADIT) and debit side of the adjustment ("natural account" 280X, which points to a different US GAAP account). This was necessary in order to demonstrate compliance with US GAAP, which also requires a step-up of the ADIT balance at the merger. Witness Ramas may not have fully understood the information provided in the Company's response to OPC Interrogatory No. 102, which included the journal entry related to the electric operations to record the tax step-up deferred income tax adjustment in conjunction with Chesapeake's acquisition of Florida Public Utilities Company, when she stated in her testimony at page 73, line 11, that the Company did not disclose the accounts, in which the original debits were booked. Her statement is, nonetheless, incorrect.

Upon obtaining proper approval, the Company intends to reclassify the debit side of the step-up entry to the appropriate regulatory asset account(s) and amortize it over a period approved by the Commission. The Company recommends 26 years, which represents the average remaining life of the plant assets consistent with the South Georgia method of tax normalization.

Q. Why is it necessary for the Company to be allowed to record the tax step-up regulatory asset and the related amortization?

A. The Commission has adopted the US GAAP deferred income tax method in accounting for income taxes. ASC 740, or previously known as SFAS 109, provides the US GAAP accounting guidance on income taxes. According to ASC 740-10-35-4, ADIT should be adjusted for the effect of a change in tax laws or rates. The change in tax rates also includes the change as a result of an acquisition or merger, as is the case for FPU, since ASC 740 does not provide an exception to acquisitions or mergers. The purpose of ADIT is to reflect the future income tax benefits or payments based on the enacted tax rate, which is, of course, based on enacted tax law expected to apply to those timing differences at the time they are realized. Since the merger with Chesapeake changed FPU's federal statutory income tax rate to 35 percent, FPU was required to adjust its ADIT balance to reflect that change, in accordance with ASC 740.

For the regulated environment, deferred income taxes represent recovery of income tax expenses by the utility from its ratepayers prior to the utility having to make those income tax payments to the US Treasury. Recording deferred income taxes on temporary differences is commonly known as normalization. Normalization is a requirement under the US Tax Code, IRC§168(i)(9), which provides that any rate-making adjustment with respect to a utility's deferred income tax reserve be consistently applied to its rate base, depreciation expense, and income tax expense. In Florida, the Commission includes deferred income taxes, or ADIT, in capital structure rather than rate base, but the same normalization rule still applies. The consequence of violating the normalization method of accounting is the loss of the utility's ability to claim accelerated depreciation for tax purposes.

Without the regulatory asset and the amortization thereof, FPU's ADIT in its capital structure, which is based on the 35 percent federal statutory income tax rate, would not be consistent with its current income tax recovery, which is based on the 34 percent federal statutory income tax rate. In order to avoid the normalization violation, FPU recorded, for regulatory purposes, both debit and credit sides of the adjustment of the initial step-up to Account 282.2, as explained above. This will ensure that ADIT in the Company's capital structure continues to be in line with the past recovery of those amounts until the Commission approves the necessary regulatory asset and amortization thereof. With the Commission's approval, FPU can properly show both ADIT and the future income taxes recovery at the required federal statutory rate of 35 percent. This will enable FPU to continue its accelerated depreciation deduction for tax purposes.

Q. Does this conclude your testimony?

A. Yes.

Q. **Please state your name, affiliation, business address and summarize your professional experience and academic background.**

A. My name is P. Mark Cutshaw. I am the Director of System Planning and Engineering for Florida Public Utilities Company (FPU or Company). My business office address is 911 South 8th Street, Fernandina Beach, Florida 32034. I joined FPU in May 1991 as Division Manager in the Marianna (Northwest Florida) Division. In January 2006, I became the General Manager of our Northeast Florida Division, and in 2013, I moved into my current position of Director of System Planning and Engineering. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. Since joining FPU, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues.

Q. **Are you the same P. Mark Cutshaw who filed direct testimony in this proceeding?**

A. Yes.

Q. **Please state the purpose of your rebuttal testimony.**

A. The purpose of my testimony is to respond to the direct testimony of Donna Ramas, filed on behalf of the Office of Public Counsel ("OPC") in this proceeding.

Q. **Are you sponsoring any exhibits with your rebuttal testimony?**

A. No, I am not.

Q. **Please summarize the key issues and areas that you will address in your rebuttal testimony.**

A. I will be addressing the area of Pole Attachments - Joint Use Costs and the proposed adjustments that are included in Witness Ramas testimony beginning on page 45, line 20 and continuing through page 47, line 12.

Q. **Do you agree with Witness Ramas's recommended adjustment to costs associated with the Pole Attachments – Joint Use Costs issue included in her testimony on page 47, line 3 through page 47, line 12.**

A. No. I do not. I recommend that the entire $10,756, which represents one-fifth of the cost of an audit on pole attachments and joint use inventory, be included in the increased test year expenses.

Q. **Is FPU required to perform this type of pole attachment joint use audit and if so where is this indicated?**

A. Yes. FPSC Rule 25-6.0342, Electric Infrastructure Storm Hardening, includes several references to "Attachment Standards and Procedures" within this rule. It is my understanding that these requirements are included based on industry experience from storm impacts during which third party attachments to utility poles were considered by many as contributing factors to damage that occurred. As a result, this rule includes several references to third party attachments, including the following selected provisions:

<u>25-6.0342 Section 4(c)</u> requires that "The utility's storm hardening plan shall provide a detailed description of its deployment strategy including, but not limited to the following: The extent to which the electric infrastructure improvements involve joint use facilities on which third-party attachments exist."

<u>25-6.0342 Section 4(e)</u> requires that "The utility's storm hardening plan shall provide a detailed description of its deployment strategy including, but not limited to the following: An estimate of the costs and benefits, obtained pursuant to subsection (6) below, to third-party attachers affected by the electric infrastructure improvements, including the effect on reducing storm restoration costs and customer outages realized by the third-party attachers."

<u>25-6.0342 Section 5</u> requires the development of "Attachment Standards and Procedures: As part of its storm hardening plan, each utility shall maintain written safety, reliability, pole loading capacity, and engineering standards and procedures for attachments by others to the utility's electric transmission and distribution poles (Attachment Standards and Procedures). The Attachment Standards and Procedures shall meet or exceed the edition of the National

Electrical Safety Code (ANSI C-2) that is applicable pursuant to Rule 25-6.034, F.A.C. so as to assure, as far as is reasonably practicable, that third-party facilities attached to electric transmission and distribution poles do not impair electric safety, adequacy, or pole reliability; do not exceed pole loading capacity; and are constructed, installed, maintained, and operated in accordance with generally accepted engineering practices for the utility's service territory."

25-6.0342 Section 6 requires the utilities to receive "Input from Third-Party Attachers: In establishing its storm hardening plan and Attachment Standards and Procedures, or when updating or modifying such plan or Attachment Standards and Procedures, each utility shall seek input from and attempt in good faith to accommodate concerns raised by other entities with existing agreements to share the use of its electric facilities. Any third-party attacher that wishes to provide input under this subsection shall provide the utility contact information for the person designated to receive communications from the utility."

Q. Are these requirements included in FPU's most recent approved Storm Hardening Plan?

A. Yes. Section 2.2 of the 2013 – 2015 Storm Hardening Plan, approved by the Commission in Docket 130131-EI, includes information regarding the Joint-Use Pole Attachment Audit. The Plan states that "FPUC currently has joint use agreements with multiple telecommunication and cable television providers. Although the agreements allow joint use attachments audits, these audits have not been completed as allowed in the contracts. Beginning in 2014, audits will be initiated with all joint use attachers in order to identify the total number of attachments and identify any violations that may exist. GIS mapping information will be used as a basis when conducting the audits."

This section goes on to state that "During the inspection process, the following data will be collected for use in analyzing the integrity of joint use poles. Based upon the significant length of time since the last joint use audit, strength and loading assessments will not be completed in this audit. The assessments will be conducted in the pole inspection program described above."

Further it states that "The information collected in the audit will be compiled and handled in accordance with the specific joint use agreement for that attachment. Any dangerous conditions identified that could result in a failure of the pole will be addressed immediately. The cost to manage the joint use audit and attachment process will be approximately $28,000 on an annual basis. The joint use audits will be conducted in accordance with the contracts for the third party attachers. Data collected during the audit process will be analyzed in order to determine the number of poles found to be overloaded, the number of unauthorized joint use attachments and customer outages related to these situations."

Furthermore, in its Order approving the Plan, Order No. PSC-13-0638-PAA-EI, the Commission specifically acknowledged that FPU, through the joint use audit, would be collecting data that ". . . will be analyzed to determine overloaded poles, unauthorized attachments, and outages relayed to these situations."

Q. **It appears based on this filing that you have not been able to comply with the Joint Use Attachment Audit requirement. What is causing the delay in completing the Joint Use Attachment Audit?**

A. FPU has very limited resources in the engineering staff. Due to the limited resources, FPU has not been able to complete the joint use attachment audit using existing employees.

Q. **What are your plans to meet this requirement?**

A. FPU will be contracting with an outside firm with expertise in Joint Use Audits to complete the audit. The plan at this point is to complete the audit during 2014 at a cost of approximately $53,781 which is based on a cost of $3.50/pole for 15,366 poles which contain joint use attachments.

Q. **Will the joint use attachers be involved in the audit?**

A. Each joint use attacher will have the opportunity to and will be encouraged to be involved in the audit in order to validate the final count and provide input into the situation should any attachment violations be found. However, the contracts for joint use attachments do not require their participation. Considering the amount of time required to perform the work, the relatively small number of attachments compared to their total attachments and the lack of a requirement in the contracts, it is very likely that they will elect not to participate.

Q. **Will joint use attachers be required to share in the costs for the audit?**

A. No. Most of FPU's current contracts with joint use attachers are quite dated and, consequently, do not specifically address cost sharing for joint use attachment audits. Going forward, we intend to clarify this issue to ensure that attachers share in the costs for joint use audits. However, as stated above, the Company does have multiple older contracts currently in place with various joint use attachers, which are simply not clear on this issue. Because the contracts are not specific on this point, the Company expects that it will be difficult, if not impossible, under the current contracts to implement audit cost sharing arrangements with the joint use attachers, particularly those that expend some of their own resources to participate in the joint use audit. Although there still remains some ambiguity on this issue, it appears likely that joint use attachers will not participate in the payment of the audit expense.

Q. **Does the estimate from TRC (BATES Label FPU RC-003064) indicate that the costs will be shared?**

A. No. The proposal referenced by witness Ramas at page 46 of her testimony does not state that the cost would be shared. Instead, it states that "it is **anticipated** that these costs will be divided equally between cable companies, telephone companies and FPUC." There is no indication by TRC that cost sharing is assured or even that the costs should be shared. Moreover, TRC could not have reached any such definitive conclusion, because it is not a party to the joint use contracts. I believe that this statement by TRC in its proposal is likely the result of a misinterpretation of our joint use billings, which is apparently what they relied upon. It is my opinion; however, based upon the lack of clarity within the current contracts as well as direct experience, that sharing of the audit costs will not occur in the absence of revised, updated contracts that specifically address cost sharing for the joint use audits.

Q. **Should the full amount of your test year increase not be approved and the joint users refuse to pay a portion of the cost, what actions will be necessary?**

A. Regardless of the final outcome of this proceeding, it will be necessary to continue with the joint use attachment audit using outside resources in order to come into compliance with requirements. Further, if the Company is not allowed to recover the joint use audit costs as requested, it will become more critical – and more likely - to that the Company will need to pursue legal action in an effort to address these issues with joint use attachers. This will result in additional time, resources and legal costs for all parties involved in order to develop the necessary new contracts providing for sharing of costs. As a result, the Company may find it necessary, at a future date, to seek approval from the Commission to recover such legal costs from its ratepayers. Likewise, I would expect that the joint use attachers would likely pass along any such additional legal costs to their customers as well, in which case many customers would be impacted not only through their electric bill, but also their cable or telephone bill.

Q. **What then is your recommendation in regard to the Joint Use Audit Cost?**

A. My request and recommendation is that the Commission allow the $10,756 amount to be included as an increase in the test year expenses as requested by FPU. The recovery of any portion of this amount from joint use attachers is very unlikely and inclusion of the entire amount should be approved.

Q. **Does this conclude your rebuttal testimony?**

A. Yes.

Q. Please state your name, affiliation, business address and summarize your professional experience and academic background.

A. My name is Aleida Socarras. I am Director of Marketing & Sales for Florida Public Utilities Company (the "Company" or "FPU"). My business address is 911 South 8th Street, Fernandina Beach, FL 32034.

Q. **Are you the same Aleida Socarras who filed direct testimony in this proceeding?**

A. Yes.

Q. **Please state the purpose of your rebuttal testimony.**

A. The purpose of my testimony is to respond to the direct testimony of witness Ramas filed on behalf of the Office of Public Counsel ("OPC") in this proceeding.

Q. Are you sponsoring any exhibits with this rebuttal testimony?

A. No. I am not.

Q. **Please summarize the key issues and areas that you will address in your rebuttal testimony.**

A. I will address specific issues raised by witness Ramas related to Advertising Expenses and Economic Development Expenses at pages 47 through 55 of her testimony. Specifically, I will address the following topic areas:

1. Support of sponsorships and golf tournament activities for advertising purposes (Ramas, pages 48-49)

2. Increase in economic development activities (Ramas, pages 54-55)

3. Shrimp Festival expenses (Ramas, pages 52-55)

Q. Witness Ramas states at page 49, line 6, that "donations, sponsorships, and golf outings are not costs that are necessary for the provision of electric service to customers" and then recommends on page 50 of her testimony that advertising expense be reduced because costs associated with such events are just "image-enhancing costs." Do you agree?

A. No, not at all. Such events and activities are a critical means, particularly for a small company like FPU, to convey information regarding utility programs and related messages, by very cost-effective means, as compared to other modes of advertising.

Q. Please explain what you mean by these events and activities providing a cost-effective means for advertising.

A. Of course. FPU works to optimize its advertising dollars and to spend those dollars in the most effective ways available to reach our audience. The costs associated with sponsorships and golf tournaments are justified, because these activities are the optimal way to convey information to customers in small, rural areas. We are sensitive to the needs and culture of the communities we serve, as well as aware of the most effective communications methods. In our unique service areas, we have found that these types of events and activities provide the most direct, effective, and cost effective means to reach our intended audience in order to promote and publicize the use of our services and available programs. As an example, I note here that Novelties for general distribution, as defined in Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, are specifically permitted for this purpose. In small rural communities, such as Marianna, as well as small, geographically confined areas, such as Fernandina Beach, business and customer relationships are extremely important and "word of mouth" is one of the best ways to disseminate information, even more so than electronic means, such as television or radio. Sponsorship of public events, including golf tournaments, provides a highly visible forum for advertising through banners, flyers, and novelties with appropriate messaging. These events also provide an opportunity for direct, one-on-one contact with customers, other residents, and community leaders through the availability of booklets, hand-outs, other presentations regarding our various programs and service offerings, along with company representatives present and available, on the spot, to address any questions regarding the materials provided. If we did not participate in these activities and, instead, relied only on mass media advertising, we would miss the opportunity to reach a wide section of our overall customer base. Consequently, our messaging would not be as effective.

Q. Upon what have you based your conclusion that these types of events are the best means by which to communicate and inform customers in your electric service areas?

A. Based on my marketing knowledge and past personal experience, I believe targeted, local, and direct means of reaching an audience tend to be more effective than mass communications. Since the 1990s, event marketing has grown faster than overall corporate advertising because it is a cost effective means of communicating with targeted audiences. FPU does use radio and TV advertising to raise awareness and create interest. However, mass media advertising needs to be reinforced with more direct channels of communication such as sponsorship of local events including golf outings. These events support our overall marketing objectives and are an economical way to reach our audience. We consider how our target audience gets their information and based on past experience, we know that in smaller communities word of mouth from trusted sources is the most effective channel of communication. Our target audience also perceives our participation in a positive way and appreciates our effort to reach out to them directly. Our employees participate in these events and are available to answer questions, expand on topics, and personally disseminate information about our services. We have found that engaging in this way with our customers leads to greater understanding and appreciation for how to best utilize our services. Also, while interacting at an event with one of our employees, the likelihood of individuals acting on the message and/or getting clarification on a topic is greater because we are able to more immediately and directly answer or clarify their questions. That immediate, direct and personal involvement reinforces our messaging and increases the chances that action will be taken more than passively listening to a radio or television ad.

Q. With regard to charitable donations that are unrelated to your advertising message, do you treat those expenditures differently?

A. Yes, we do. We make a clear distinction between a donation for which we do not receive any benefit and/or are not able to convey a message promoting the use of our services and those situations where the costs incurred include substantial means for us to convey our message consistent with the guidelines outlined FERC's Uniform System of Accounts for Account 913. Donations for which we receive no benefit or advertising value are booked below-the-line.

Q. Witness Ramas questions the Company's requested increase in Economic Development Expense at page 54 of her testimony and recommends, at page 55, that the amount allowed be limited to $27,000 per year. Do you agree with her conclusion?

A. No. While she is certainly correct that the amount requested by FPU for Economic Development is higher than what FPU has spent, on average, since the last rate case, her conclusion fails to take into consideration that we have proposed a new, defined Economic Development program, whereby we propose to greatly expand our economic development activities in both divisions While FPU has always been involved in economic development activities in our service territory, as outlined in our Economic Development Program description, we would like to further extend our efforts and to implement a more robust, detailed and formalized Economic Development Program to enhance even further our work to promote economic development in the communities we serve. We believe an expanded, formalized program, with targeted goals and defined implementation strategies, will help us better direct our efforts and resources so that they can be most beneficial to each community's economic development efforts, but will also help us have a greater impact on the communities we serve. In contrast, under witness Ramas' proposal, we would be able to do only minimally more than we are currently doing in terms of economic development activities. More importantly, we would not be able to implement the majority of the strategies contemplated by our proposed Plan, and therefore, could not provide the assistance to our communities at the levels we had intended.

Q. Witness Ramas takes specific issue with recovery of expenses associated with the Shrimp Festival at pages 53 and 54 of her testimony. Why were the costs related to the Shrimp Festival appropriately reflected as advertising expense?

A. As I have noted above, each community we serve is unique in its composition, culture and opportunities for community interactions. In Fernandina Beach, the Shrimp Festival is by far the most unifying, community identification event for the City. Our participation in the Shrimp Festival allows us to reach a large audience like no other event does. In addition, the weeks of preparation and involvement leading up to the event, provide an excellent opportunity for us to reinforce and promote our services, and also to interact with community leaders that are allies in promoting information and services that help our customer base. In addition, the event attracts thousands of visitors to the community who purchase services and products from the various local establishments and vendors that participate in the event. This event has a significant economic impact in the community, and the Company's participation helps promote and ensure the success of this event. To be clear, witness Ramas is incorrect in her statement at page 53, line 16, that the Company has historically considered Shrimp Festival costs as Economic Development costs. To the contrary, historically, the Company has treated the Shrimp Festival as an advertising expense and the costs were charged to Account 913 for all of the reasons stated above. With the development of our new Economic Development Program, however, we reviewed our past involvement with the Shrimp Festival and determined that this event definitely has economic development benefits for the community beyond simple advertising. As such, we determined that reassigning these expenses into Economic Development was a more appropriate reflection of the benefits of the event. While it can, at times, be difficult to make a distinction between advertising and economic development costs, we believe that the key benefits of the event accomplish the primary objective of reaching our target audience to promote economic development. Nonetheless, I believe that they could be also be appropriately characterized as advertising expense. In either event, the expenses associated with this event are reasonable and prudent. Our involvement in the event also meets multiple objectives recognized as appropriate for recovery through base rates. As such, whether characterized as advertising expense or as economic development expense, the expenses associated with the Shrimp Festival should be allowed for recovery.

Q. **Do you agree with witness Ramas' recommended adjustment to Advertising Expense at page 48, line 4, through line7?**

A. No, I do not agree with the requested adjustment for the reasons stated above.

Q. **Do you agree with witness Ramas' recommended reduction to Economic Development Expense at page 48, line 11 through line 13?**

A. No, I do not agree with the requested reduction for the reasons stated above.

Q. Does this conclude your rebuttal testimony?

A. Yes.

INTRODUCTION

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

A. My name is Paul R. Moul and I am Managing Consultant at the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q. **Mr. Moul, have you previously submitted direct testimony in this proceeding?**

A. Yes. My direct testimony was submitted with the Company's case-in-chief on May 14, 2014.

Q. **What is the purpose of your rebuttal testimony?**

A. Florida Public Utilities Company ("FPUC" or the "Company") has requested that I comment on and rebut the testimony presented by Dr. J. Randall Woolridge, a witness appearing on behalf of the Office of Public Counsel ("OPC").

Q. **Please identify the principal areas of controversy concerning the rate of return issue in this proceeding.**

A. The three principal cost of capital areas in dispute in this case are the Company's: (1) cost of short term debt, (2) common equity ratio, and (3) cost of equity. Witness Woolridge proposes three adjustments to the cost of capital calculation provided in my direct testimony. Each adjustment has the effect of lowering FPUC's cost of capital. Collectively, witness Woolridge's three adjustments have the effect of reducing the Company's cost of capital from the 8.60% that I support to 6.80%, a difference of 180 basis points. A summary of each of the cost of capital proposals is attached as

Rebuttal Exhibit PRM-2, page 1.

THE COMPANY'S PROSPECTIVE COST OF SHORT TERM DEBT

Q. **Witness Woolridge has submitted an alternative cost of short-term debt cost rate. Is his proposal appropriate?**

A. No, for several reasons.

First, he rejects my use of a well-respected, independent third party source of interest rates without any analysis. He simply states that the forecasted rates "are simply not credible." I find this unsupported conclusion particularly ironic as witness Woolridge actually uses as part of his calculation of the short term debt cost rate one of the forecasts he characterizes as "simply not credible."

Second, two of the three data points Witness Woolridge uses to develop his short term debt cost rate are not forecasted interest rates but are current interest rates. Both of these current rates will be historical before the final rates in this case become effective. The use by witness Woolridge of current LIBOR rates is not proper given that the Company's rates are being set for the future. Forecasts, on the other hand, capture interest rates that will be in effect when the final rates will be in effect, and they reflect the trend toward higher interest rates as monetary policy becomes more normalized.

Q **Please elaborate on your observation that Witness Woolridge actually relied upon forecasted data that he summarily dismissed as not credible.**

A. As I explain at pages 21 and 22 of my direct testimony, in developing both my long term debt cost rate and my short term debt cost rates, I used Blue Chip Financial Forecasts' (Blue Chip) December 1, 2013 long-range forecasts of interest rates. To some extent, witness Woolridge also did so.

I used Blue Chip forecasts to verify the reasonableness of the long-term debt cost rates for the Company's planned long term debt issuances in 2014 and 2015. These planned issuances and their associated cost rates were used to develop FPUC's proposed parent company cost of debt of 4.90%. It should be noted that witness Woolridge accepts my long-term debt cost rate of 4.90% that was based, in part, on this Blue Chip Financial Forecast. ("I will use Mr. Moul's recommended cost rates for the parent company long-term debt." Woolridge Direct at p. 21, line 11)

As I also explained on page 22 of my direct testimony, I used the same Blue Chip to develop my forecast of the Company's short term debt cost rate. I took the Blue Chip forecasted values for LIBOR for the years, 2015, 2016, 2017 and 2018. FPUC expects that its rates in this case would be effective during that period. To that I added the 1.10% margin that the Company is required to pay above LIBOR according to its short-term credit facility.

Blue Chip's forecast for LIBOR ranged from 0.90% in 2015 to 4.00% for 2018. It was these forecasted rates that witness Woolridge rejected as not being credible. But he used the Blue Chip 2015 LIBOR rate of 0.90%, saying that he acknowledged "the possibility that LIBOR rates will increase." So, witness Woolridge, relied upon a Blue Chip interest forecast of which he was critical.

Q **You have noted that witness Woolridge rejected the Blue Chip forecast as not credible. Does he explain his conclusion?**

A. No. In the absence of any analysis, I find witness Woolridge's position particularly troubling.

Witness Woolridge failed to acknowledge that the forecasts he claims as not being credible were from a highly respected source of interest rate forecasts. Blue Chip does not actually make forecasts of interest rates itself. Rather, Blue Chip conducts a monthly survey of noted economists from academic institutions, banking, brokerage, business consulting, financial institutions, investment advisory firms, and rating agencies. Presently, there are forty-eight (48) contributors to the Blue Chip survey (the list of contributors is contained in Exhibit No. PRM-2, page 2). Blue Chip takes the results of its monthly surveys and publishes the consensus of these individual forecasts. The major attributes of Blue Chip are its independence, the influence that it has on investors' expectations of future interest rates, and the objectivity of the survey that encompasses the wide range of viewpoints obtained from a broad sample of renowned economists. Witness Woolridge never mentions any of these attributes of Blue Chip nor challenges the objectivity of the consensus that it publishes.

Witness' Woolridge's lack of analysis does not stop with his failure to acknowledge the validity of <u>Blue Chip</u>. He never attacks the methodology <u>Blue Chip</u> uses to conduct its survey, nor the members of the panel of economists that it surveys. Further, witness Woolridge never looks to other respected, independent third parties to buttress his dismissal of the <u>Blue Chip</u> forecasts. Witness Woolridge does not offer another forecasting entity's forecast of LIBOR rates or show that another source is superior to the panel of economists that <u>Blue Chip</u> uses. In short, he offers no analysis or alternative to <u>Blue Chip</u>. Instead, he offers his totally unsupported opinion in one brief sentence.

Q **The second reason you gave for the Commission to reject witness Woolridge's short-term debt cost was that two of the three data points he used in his calculation were not forecasts but then current short-term LIBOR rates. Please explain why this makes witness Woolridge's calculation faulty.**

A. Witness Woolridge uses current LIBOR rates (i.e., he blends a one-month and three-month LIBOR rate) that have already occurred. The Company's rates are being set for a number of years into the future. The short-term debt rates should reflect debt costs over that time period, not debt costs that existed in the past. Short-term interest rates change. By definition, current short rates will not be effective for more than a year. The two current rates witness Woolridge chose to use will exist only for the 1-month or 3-month periods following their measurement. Rather, to match the Company's costs with the rate effective period, forecasts of LIBOR rates should be employed.

Forecasts reflect the best estimate of what those rates will be when the rates to be set in this case are to be in effect. Blue Chip's forecasted LIBOR rates reflect the trend toward higher interest rates as monetary policy becomes more normalized. Blue Chip's forecast recognizes that debt costs are expected to trend upward from historically low levels, a fact pointed out by witness Woolridge. He, however, fails to adequately assess whether such historically low interest rates are likely to continue into the future. Based upon their consensus, Blue Chip's forecast recognizes that today's historically low interest rates will not continue into the indefinite future. Moreover, their forecast is consistent with the Company's internal forecast.

The Company's internal forecast expects short-term rates to increase over the next five years with a move to normalized monetary policy. The forecast for LIBOR was 40 bps plus 5 bps per month for 2014 and 2015 to an average 68 bps and 128 bps plus 110 bps. Moreover, the five year SWAP rate is 1.77%, which verifies the Company's LIBOR assumption.

Witness Woolridge's attack on the Blue Chip forecast rates that I used in my prefiled direct testimony has no basis. As further support for my use of the Blue Chip forecast, I have looked at other forecasts of interest rates. The comparisons are:

	2015	2016	2017	2018	Average
Blue Chip (LIBOR)					
December 1, 2013	0.90%	2.20%	3.30%	4.00%	2.60%
June 1, 2014	0.53%	2.10%	3.20%	3.80%	2.41%
Blue Chip (FedFunds)					
June 1, 2014	0.33%	1.80%	3.00%	3.60%	2.18%
Value Line (FedFunds)					
May 23, 2014	0.30%	2.00%	3.50%	4.00%	2.45%
EIA (FedFunds)					
December 2013	0.12%	1.53%	3.46%	3.93%	2.26%
Global Insight (FedFunds)					
Third Quarter 2013	0.37%	2.15%	3.83%	4.00%	2.59%

Even though the alternative projections by Value Line, EIA and Global Insight relate to forecasts of the Fed Funds rate, rather than LIBOR, they fully support the proposition that Blue Chip established. Namely, short-term interest rates will increase for the rate effective period. Therefore, it is entirely reasonable to use the Blue Chip forecasts for setting rates for FPUC. It is certainly more reasonable to use this forecast than witness Woolridge unsupported assertion.

CAPITAL STRUCTURE

Q. **How does the Company's capital structure proposal differ from that advocated by witness Woolridge?**

A. The Company has proposed its actual forecast capital structure for the future rate year. In contrast, witness Woolridge has proposed a hypothetical capital structure. His approach proposes a 50% common equity ratio and, for the significant amount of equity capital he erases from the Company's capital structure, he replaces it with (imputes) additional capital having a lower cost of debt. In determining what type of debt he imputes, he apportions it between short-term debt and long-term debt according to the proportions contained in the Company's filing. Witness Woolridge's proposal should be rejected for several reasons.

First, the Company's actual capital structure should be used to establish rates. That reflects the mix of funds that currently supports the business and management's assessment of the mix of capital that is appropriate for the future when rates are in effect. A similar mix of funds was used by CPU to purchase FPUC, and that is the mix of funds used to make investments to serve FPUC's customers. As to witness Woolridge's guess that the Company's proposed capital structure may be associated with a relatively high level of unregulated business, this guess is incorrect. The assets of CUC that are rate regulated represented 85% of its total assets. As a consequence, the regulated side of CUC's businesses dominate its operations, and hence its financing decisions.

Second, the Company's actual capital structure is within the range of ratios previously accepted by the Commission. I have provided full justification for the common equity ratio proposed by the Company in my prefiled direct testimony. On the basis of the Company's small size and the fact that my Electric Group has a 57.58% common equity ratio based on their market capitalization, the Company's proposed common equity ratio is entirely reasonable. Moreover, the Commission has accepted common equity ratios up to 59.1% in the March 17, 2010 rate case decision for Florida Power & Light (Docket No. 090130-E). As the Commission stated:

> "...we approve the capital structure shown on Schedule 2, attached to this order. This capital structure reflects an equity ratio as a percentage of investor capital of 59.1 percent for 2010. While this relative level of equity is near the top of the range of equity ratios of the IOUs owned by the companies in witness Avera's proxy group, it is still within the range of equity ratios of comparably rated IOUs. In addition, this equity ratio is consistent with the relative level of equity FPL has maintained, on an adjusted basis, over the past decade."

Third, viewing the data presented on page 2 of Exhibit JRW-5, the range of common equity ratios for witness Woolridge's proxy group extends to 54.67%, and his proxy companies are vastly larger than FPUC. On the basis of its very small size, a higher common equity ratio is required for the Company to offset its higher business risk (e.g., companies select their common equity ratios based on their business risk -- high business risk warrants a higher common equity ratio, while lower business risk will allow a lower common equity ratio). In addition, the Value Line reports provide the investor expected common equity ratios for the electric companies shown on page 2 of Exhibit JRW-5. Those ratios are tabulated below.

		Common Equity Ratio		
Ticker	**Electric Group**	2014	2015	2017-19
AEP	American Electric Power	48.5%	47.0%	48.0%
CNP	CenterPoint Energy	36.5%	37.5%	40.5%
CNL	Cleco Corp.	57.5%	57.5%	66.0%
D	Dominion Resources, Inc.	36.5%	38.5%	41.5%
Duk	Duke Energy Corp.	50.5%	49.5%	47.5%
ETR	Entergy Corp.	43.5%	41.0%	44.5%
NEE	NextEra Energy, Inc.	44.5%	47.0%	51.5%
OGE	OGE Energy Corp.	56.0%	58.0%	58.5%
SCG	SCANA Corp.	46.0%	45.5%	47.5%
SO	Southern Company	44.5%	43.0%	42.5%
TE	TECO Energy, Inc.	45.0%	44.0%	44.0%
	Average	46.3%	46.2%	48.4%

Source of Information: Value Line Investment Survey, May 23, 2014 and June 20, 2014

As shown above, the common equity ratios for these companies reach up to 66.0%. It is clear, that the common equity ratio proposed by the Company is reasonable because it falls within the range of common equity ratios that investors expect for the electric companies.

COST OF EQUITY

Q. **What cost of equity has been proposed by witness Woolridge?**

A. Witness Woolridge has proposed an unrealistically low range of 8.75% to 9.00% rate of return on common equity.

Q. **What has caused this to happen?**

A. Witness Woolridge has based his cost of equity proposal principally on the DCF model. He has supplemented his DCF findings with the CAPM, but his CAPM result is totally unrealistic, which witness Woolridge at least tacitly acknowledges by choosing a cost of equity range well above his CAPM results. The specific infirmities of his analyses include:

- The return level that will not be acceptable to the financial community.
- The determination of an unreasonable Discounted Cash Flow (DCF) cost rate.
- Failure to recognize flotation costs as a component of the cost of equity.
- CAPM results by witness Woolridge that do not come close to capturing investor expectations.
- Inadequate consideration of the results generated by other methods, such as the Risk Premium and Comparable Earnings methods.

Q. **How would the financial community react to the Commission's acceptance of the cost of equity proposed by witness Woolridge?**

A. The financial community would be extremely concerned, if not shocked, if the Commission set the Company's cost of equity at the level proposed by witness Woolridge. The rates of return on common equity of 8.75% to 9.00% proposed by witness Woolridge are seriously deficient and will not provide FPUC with the opportunity to earn its investor required cost of capital for the rate effective period. Technical disputes about methodology and data aside, witness Woolridge's proposed cost of equity is simply not representative of the returns investors can earn on other investments of comparable risk, including investments in other utilities like FPUC. In this regard, it is worthwhile to establish a benchmark that compares the returns proposed by witness Woolridge. Regulatory Research Association ("RRA"), a service provided by SNL Financial, contains these data. The RRA report provides authorized rates of return by state commissions nationally. According to RRA, the average authorized return for electric utilities was 10.12% for 2014 through the second quarter. The range of returns was 9.20% to 12.00%.

To my knowledge, there have been no electric utilities for which the Commission authorized equity returns of 8.75% to 9.00% in modern times. In this regard, the Commission has set or accepted the following returns for Florida electric utilities.

Company	Case Identification	Date	Return on Equity Authorized
Gulf Power Company	D-110138-EI	2/27/2012	10.25%
Gulf Power Company	D-130140-EI	12/3/2013	10.25%
Florida Power & Light Company	D-120015-EI	1/14/2013	10.50%
Florida Power & Light Company	D-080677-EI	6/10/2009	10.00%
Duke Energy Florida, Inc.	D-090079-EI	6/10/2009	10.50%
Duke Energy Florida, Inc.	D-120022-EI	3/8/2012	NA
Tampa Electric Company	D-130040-EI	9/30/2013	10.25%
Tampa Electric Company	D-080317-EI	4/30/2009	11.25%

Q. **Are there other objective indications of the level of returns expected by investors which shows that the proposed cost of equity by witness Woolridge is much too low?**

A. Yes. These are revealed by the returns forecast by <u>Value Line</u>. As revealed by the returns provided below, investors expect the companies in the Electric Group to achieve returns well above those proposed by witness Woolridge.

		Return on Common Equity		
Ticker	**Electric Group**	2014	2015	2017-19
AEP	American Electric Power	10.0%	9.5%	10.0%
CNP	CenterPoint Energy	11.0%	11.5%	13.0%
CNL	Cleco Corp.	9.0%	10.5%	10.5%
D	Dominion Resources, Inc.	17.0%	17.0%	15.0%
DUK	Duke Energy Corp.	7.5%	8.0%	8.0%
ETR	Entergy Corp.	11.0%	9.0%	10.0%
NEE	NextEra Energy, Inc.	11.5%	11.0%	12.0%
OGE	OGE Energy Corp.	12.5%	12.0%	12.0%
SCG	SCANA Corp.	10.5%	10.0%	10.0%
SO	Southern Company	13.0%	12.5%	12.5%
TE	TECO Energy, Inc.	9.5%	9.5%	12.0%
	Average	11.1%	11.0%	11.4%

Source of Information: Value Line Investment Survey, May 23, 2014 and June 20, 2014

Q. **What have you concluded about the types of returns that investors expect to be realized by FPUC as a result of this proceeding?**

A. Investors will expect returns higher than those proposed by witness Woolridge. The RRA report shows a 10.12% return, prior Commission orders show an average return of 10.43%, and the returns forecast by Value Line average 11.0% to 11.4%. This evidence clearly shows that investors expect much higher returns than those proposed by witness Woolridge.

DISCOUNTED CASH FLOW

Q. Witness Woolridge and you have used the DCF model to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. In my view, the use of more than one method provides a superior foundation for the cost of equity determination. This is particularly true today given the wide swings in share values and the overall financial market uncertainty. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.).

Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by witness Woolridge and me. It must be recognized, however, that this form of the DCF method employs assumptions which are simply not realistic. For example, according to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same constant rate absent any change in dividend payout and price-earnings multiple. There is no evidence that these conditions actually prevail in the equity markets.

DCF GROWTH RATE

Q. **As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?**

A. The theory of the DCF holds that the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share and dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be emphasized. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (another key assumption of the DCF model). It is also important to recognize that analysts' forecasts significantly influence investor growth expectations as apparently witness Woolridge acknowledges. Finally, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model is forecasts of earnings per share growth.[1] For these reasons, earnings per share forecasts must be given primary weight.

Q. **Witness Woolridge has questioned the reliability of analysts' forecasts of earnings per share growth in the DCF model. Do you agree?**

A. No, I do not. Indeed, witness Woolridge uses analysts' forecasts extensively in his

[1] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

DCF analysis.

Q. **Do you agree with witness Woolridge's view that analysts' forecasts of earnings per share contain some form of bias?**

A. I find inadequate support for this assertion. With the final judgment entered on October 31, 2003 in the Global Research Analyst Settlement ("GRAS")[2], which resolved the equity research analysts practices at major investment banks that had been accused of conflicts of interest, Wall Street firms have separated their research and investment banking services. I find witness Woolridge's criticism of analysts' forecasts somewhat perplexing because he provides extensive evidence of analysts' forecasts (see pages 4 and 5 of Exhibit JRW-10) in his DCF analysis. I also do not understand why Witness Woolridge would have difficulty accepting analysts' forecasts because the Claus and Thomas study, included as his first entry under the heading "Ex Ante Models (Puzzle Research)" on page 5 of Exhibit JRW-11, used analysts' earnings forecasts taken from I/B/E/S, now part of Thomson Financial that witness Woolridge reports as the Yahoo growth estimates (see page 5 of Exhibit JRW-10).

Moreover, it matters not what witness Woolridge may think about the analysts' forecasts. Rather, what is important is what investors actually use in their decisions regarding the purchase, sale or holding of stocks. That is to say, even if there were some bias in the forecasts which suggested that some downward adjustment might be

[2] SEC v. Bear, Stearns & Co., Inc., No. 03 Civ. 2937, 2003 U.S. Dist. LEXIS 19359 (S.D.N.Y. Oct. 31, 2003)

appropriate, the price of stock would likewise require a downward adjustment to remove the influence of the same bias that is reflected in the price that was established with the actual analysts' forecasts. The bottom line is that the growth rate must be synchronized with the price that investors establish when valuing a stock. Otherwise, the DCF result would be mis-specified.

Q. **Witness Woolridge has also provided dividends per share growth rates published by <u>Value Line</u> on page 4 of Exhibit JRW-10. Are these growth rates useful in the DCF?**

A. No. The <u>Value Line</u> forecast growth rates of 4.8% in dividends per share (see page 4 of Exhibit JRW-10) are below the growth in earnings (i.e., Yahoo, Zacks, and Reuters). The reason dividends per share growth are less than the earnings growth is that the dividend payout ratios are forecast to decline. This is shown by the <u>Value Line</u> data presented below.

Ticker	Electric Group	All Div'ds to Net Prof 2014	2015	2017-19
AEP	American Electric Power	60%	63%	64%
CNP	CenterPoint Energy	83%	83%	79%
CNL	Cleco Corp.	62%	54%	57%
D	Dominion Resources, Inc.	69%	68%	70%
Duk	Duke Energy Corp.	71%	68%	64%
ETR	Entergy Corp.	53%	63%	59%
NEE	NextEra Energy, Inc.	55%	57%	57%
OGE	OGE Energy Corp.	45%	49%	53%
SCG	SCANA Corp.	58%	58%	55%
SO	Southern Company	73%	74%	72%
TE	TECO Energy, Inc.	87%	83%	65%
	Average	65%	65%	63%

Source of Information: Value Line Investment Survey, May 23, 2014 and June 20, 2014

For this reason, earnings growth should be emphasized.

Q. **Witness Woolridge also appears to have considered, and perhaps to have given some weight to, historical growth rates in earnings, dividends, and book value. Please comment.**

A. History cannot be ignored. However, in developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance.

Q. **Did witness Woolridge also consider retention growth?**

A. Yes. However, the retention growth formula was misapplied on page 4 of his Exhibit JRW-10. Those misapplications are discussed below.

Q. **Apart from these theoretical deficiencies, has witness Woolridge properly determined retention growth?**

A. No. Witness Woolridge has relied upon the Value Line forecasts of year-end. Value Line defines "return on equity" as follows:

> Percent Earned Common Equity – net profit less preferred dividends divided by common equity (i.e., net worth less preferred equity at liquidation or redemption value), expressed as a percentage. See Percent Earned Total Capital.

Without an adjustment to convert the Value Line forecast returns from year-end to average book values, there is a downward bias in the results. This is because with an increasing book value driven by retention growth, the average book value will be less than the year-end book value. For that reason, the Federal Energy Regulatory Commission ("FERC") adjusts the year-end returns to derive the average yearly return, using the formula 2 (1 + G) / (2 + G) (see 92 FERC ¶ 61,070). Generally speaking, this adjustment increases the retention growth rate.

Q. **Has witness Woolridge included external financing growth in his internal growth analyses?**

A. No. This omission results in a further downward bias in his growth rate analysis. Forecasts by Value Line indicate that future growth from external stock financing will add to the growth in equity. This would result in an internal/external growth rate higher than that developed by witness Woolridge.

Q. **What growth rate would be indicated using average book values and external financing growth?**

A. I have used a variant of the FERC's adjustment procedure to clearly show the numerical components that produce the average book value per share. I have reported the results of my analysis on Exhibit No. PRM-2, page 3. Here, the use of the average book value in the calculation provides an 11.51% forecast return on average book common equity, a return higher than the 11.4% return on year-end book value, which was used by witness Woolridge on page 4 of Exhibit JRW-10. I also show on Exhibit No. PRM-2, page 3 that the external growth is 0.87%. Combined, the growth from both internal and external factors produces a growth rate of 5.02%, as shown on Exhibit No. PRM-2, page 3. This growth rate exceeds substantially the 4.1% internal growth rate calculated by witness Woolridge on page 4 of Exhibit JRW-10.

FLOTATION COSTS

Q. Witness Woolridge has failed to modify his DCF results for the flotation costs. Has the omission of this adjustment resulted in an understatement of the required rate of return on common equity?

A. Yes. I should note that witness Woolridge's position concerning flotation costs is inconsistent with the Value Line forecasts (see Exhibit No. PRM-2, page 3) that show electric companies will be issuing new common stock in the future. Moreover, historically the companies that comprise my Electric Group have issued significant quantities of new equity (see page 11 of Exhibit No. PRM-1) that accompanies my prefiled direct testimony. As explained in my prefiled direct testimony, these companies made twenty-six issues of new common stock during the period 2007 to 2011. And Value Line indicates they will continue to do so in the future.

In response to witness Woolridge's arguments, the relative market price of stock in relation to the book value of stock ratio has no bearing on whether a flotation cost adjustment is proper. These costs are incurred regardless of the relationship of the stock price to book value. As to the issue of the underwriting spread, witness Woolridge is wrong to argue that this is not a legitimate flotation cost. The underwriting spread is represented the difference between the market price of stock and the gross proceeds realized by a company for selling new stock. It is what the investment bankers retain which is not available to a company and reflects a true flotation cost. This is because the utility can only invest the net proceeds received from a stock offering in its rate base after the underwriting spread and out-of-pocket expenses have been paid. That is to say, the rate base investment from a common stock offering can only be made with the net proceeds and not the price of stock paid by investors. As to witness Woolridge's argument about brokerage fees paid by investors to transact a purchase or sale of stock, they are entirely irrelevant to the issue. It is only the amounts realized by the utility after the impact of the underwriting spread and out-of-pocket expenses that affects the net proceeds that are available to invest in rate base.

Q **What is your reaction to witness Woolridge's recommendation that if the Company experiences equity issuance costs, they should "be treated as a cost of service?"**

A. After arguing for several pages that flotation costs do not exist, he suggests that equity issuance costs (more commonly called "flotation costs") should be treated as a cost of service item rather than as an adjustment to the cost of equity. What is interesting is witness Woolridge's implicit concession that flotation costs may exist. Whether the adjustment for flotation costs becomes part of the cost of equity or whether those costs are part of the "cost of service," both treatments impact the Company's revenue requirements. It is important to realize that the cost of raising equity is a cost just like the cost of issuing debt but those costs are not included in O&M expense. They become part of the embedded cost of debt when setting rates. Similarly, flotation costs traditionally become part of the cost of equity. Witness Woolridge seems to be arguing over the recovery mechanism associated with recovering flotation costs. However, the Company has not requested flotation costs in determining net operating income, so, if they are not recognized in the cost of equity, they would be denied recovery. Cost of equity treatment of flotation costs is the only equitable approach in this case.

RISK PREMIUM METHOD

Q. **Do you agree with witness Woolridge's rejection of the Risk Premium method in determining the cost of equity?**

A. No. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity which must be higher than the cost of debt in recognition of the higher risk of equity. So, while witness Woolridge declines to use the Risk Premium approach to measure the Company's cost of equity, it is an approach which provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk used in the CAPM.

Q. **Please continue with your response to witness Woolridge's criticisms of the risk premium approach.**

A. As a preliminary matter, witness Woolridge's observation that the yield that I used on A-rated public utility bonds is higher than the current yield on those bonds misses the point. My yield reflects the forecast trend toward higher yields. As such, witness Woolridge provides a mismatched comparison that is not relevant for the prospective cost of equity. Concerning his arguments on pages 62-63, witness Woolridge seems troubled with use of the yield on A-rated public utility bonds because they contain interest rate risk and default risk. These are invalid criticisms because common stock investors are faced with these same risks. Moreover, if the compensation for these risks were removed from the yield on A-rated public utility bonds, then the resulting risk premium would be larger when computed from a smaller base yield applicable to Treasury bonds, for instance.

As to the historical relationship between stock and bond return, it is an enduring one. His criticisms are invalid because: (1) common stock investors are subject to changing levels of interest rates because a primary determinant of the cost of equity is the level of interest rates (especially for utility stocks), and (2) the credit risk associated with a company's bonds is also a major concern for common stock investors (e.g., default on a company's bonds would adversely affect the common stockholders).

Q. **Please address the alphabetic medley of criticisms of the risk premium approach listed by witness Woolridge in his Appendix D (i.e., Exhibit JRW-16).**

A. Most of these require only a brief response. I will address each, in turn.

As to item (A), (biased historical returns) the capital losses concerning historical bond returns were non-existent for long-term government bonds (used by witness Woolridge as a proxy for bond yields). Over the period 1926-2013, capital appreciation (rather than capital losses) was 0.2% as the geometric mean and 0.6% as the arithmetic mean. Hence, his claim of losses is not correct.

Witness Woolridge also does not identify the magnitude of any difference between the published yield and investor expected returns on bonds. With bond portfolio immunization strategies, a desired rate of return can be achieved over a fixed investment horizon when the duration of a bond portfolio equals the investment horizon. Strategies such as these point to the extremely high probability of realizing expected returns on public utility bonds from issuance to maturity, absent default. Consequently, witness Woolridge's reasoning provides no basis to reject my risk premium approach.

As to item (B) (the arithmetic vs. geometric mean returns), witness Woolridge criticizes my use of arithmetic means in applying the risk premium method. However, as stated in the 2003 Yearbook published by Ibbotson Associates:

> The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values....This makes the arithmetic mean return appropriate for forecasting, discounting, and computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount his expected (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will, Therefore, require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit his capital to the investment.

In the 2006 Yearbook, Ibbotson added:

> A simple example illustrates the difference between geometric and arithmetic means. Suppose $1.00 was invested in a large company stock portfolio that experiences successive annual returns of +50 percent and -50 percent. At the end of the first year, the portfolio is worth $1.50. At the end of the second year, the portfolio is worth $0.75. The annual arithmetic mean is 0.0 percent, whereas the annual geometric mean is -13.4 percent.

Both are calculated as follows:

$$r_A = \frac{1}{2}\ (0.50 - 0.50) = 0.0, \textit{ and}$$

$$r_G = \left[\frac{0.75}{1.00}\right]^{\frac{1}{2}} - 1 = -0.134$$

> The geometric mean is backward-looking, measuring the change in wealth over more than one period. On the other hand, the arithmetic mean better represents a typical performance over single periods.
>
> In general, the geometric mean for any time period is less than or equal to the arithmetic mean. The two means are equal only for a return series that is constant (i.e., the same return in every period). For a non-constant series, the difference between the two is positively related to the variability or standard deviation of the returns. For example, in Table 6-7, the difference between the arithmetic and geometric mean is much larger for risky large company stocks than it is for nearly riskless Treasury bills.

As to item (C) (the large error in measuring the equity premium using historical returns), witness Woolridge points to the relatively high standard deviation of the historically measured risk premium as an indication of possible forecasting error. But, he misinterprets the relatively high standard deviation. Rather, the relatively high standard deviation is a reflection of the basic riskiness of common stocks. Since common stocks are more risky than bonds or other low risk investments, then the standard deviation should be relatively high, because common stocks provide more uncertain returns as compared to more certain returns for lower risk bonds. If as witness Woolridge asserts, the common equity risk premium is unreliable because the standard deviation is relatively high, then he is repudiating the basic riskiness of common stocks.

As to item (D) (unattainable and biased historical stock returns), with the proliferation of stock-index mutual funds and exchange-traded funds ("ETF") that are designed to replicate the returns on major indexes, the overall market returns are attainable. While there may be transaction costs associated with both stock-index mutual funds (which are minimal for low cost managers, such as The Vanguard Group) and ETFs (which can be purchased and sold through discount on-line brokerage accounts), witness Woolridge's criticisms are misplaced.

As to item (E) (company survivorship bias), the survivorship issue is not a valid criticism because the historical returns contain the results of the companies that comprised the index in each year. That is to say, as companies entered and exited the index, the market performance in each year reflected the companies in the index each year. Obviously, Microsoft Corporation had no impact on the S&P 500 return in 1960, nor does Nash-Kelvinator Corporation impact the returns of the S&P 500 in 2013. But, these companies did provide returns to investors in the years that they were included in the index.

As to item (F) (The "Peso Problem" – U.S. stock market survivorship bias), witness

Woolridge provides no quantification of the impact of the "peso problem" on the historical return. Just as higher than expected returns may have been experienced in the past, so too lower than expected returns also were experienced. Further, the possibility of "highly improbable returns" (e.g., positive or negative) is the reason that long time series are used in the risk premium analysis.

CAPITAL ASSET PRICING MODEL

Q. **Do you have concerns regarding the application of the CAPM by witness Woolridge?**

A. As a preliminary matter, witness Woolridge produced a 7.5% and 7.6% CAPM results that are simply not credible. This is especially true in the circumstance where the yield on Baa rated public utility bonds were 4.90% for the six-months ended June 2014. The cost of equity simply must be higher than the cost of debt by a meaningful margin, which is not the case with witness Woolridge's CAPM. Witness Woolridge's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of a wholly unrealistic market premium, (ii) his failure to make a size adjustment, and (iii) his failure to adjust his CAPM result for flotation costs. Ultimately, witness Woolridge appears to give little or no weight to his CAPM analysis, adopting a return on equity range that is well above his CAPM results. His ultimate recommended return on equity suggests that he does not deem his CAPM returns to be credible.

Q. **How has witness Woolridge approached the risk-fee rate of return component of the CAPM?**

A. Both witness Woolridge and I have used the yield on 30-year Treasury bonds for the risk-free rate of return component of the CAPM. Unlike my approach, which included forecasts of these yields, witness Woolridge relied excessively on recent data when he selected a 4.0% risk-free rate of return. Rather, the <u>Blue Chip</u> forecasts indicate higher yields on Treasury obligations for the future. The June 1, 2014 <u>Blue Chip</u> shows the yield on 30-year Treasury bonds increasing from 3.69% in the first quarter of 2014 to 4.3% in the third quarter of 2015. Of course, this forecasted interest rate increase for Treasury Bills is consistent with the long term bond rate increase consensus forecasted by <u>Blue Chip</u> that I and witness Woolridge relied upon in setting FPUC's cost of long term debt.

Q. **What are your observations regarding witness Woolridge's use of the geometric mean?**

A. Witness Woolridge has incorrectly considered the geometric mean when analyzing historical returns (see page 5 of Exhibit JRW-11). The theoretical foundation of the CAPM requires that the arithmetic mean must be used because it conforms to the single period specification of the model and it provides a representation of all probable outcomes and has a measurable variance. As explained above, the geometric mean, which consists merely of a rate of return taken from two data points and cannot provide a reasonable representation of the market risk premium in the context of the CAPM. In short, the arithmetic mean provides an unbiased estimate, captures all probable outcomes, and has a measurable variance. I have covered this issue in additional detail above.

Q. **Do you have additional observations concerning the CAPM as applied by witness Woolridge?**

A. Yes. It appears to me that witness Woolridge has substantially misstated the return on the market as a whole from which he calculates his market premium (i.e., *Rm-Rf,* where *Rm* is the return on the market as a whole and *Rf* is the risk-free rate of return). The returns he provides, such as 7.50% (see page 1 of Exhibit JRW-C1), cannot possibly be correct. What witness Woolridge shows on his bar graph on page 1 of Exhibit JRW-C1 is that the S&P 500 has a DCF return that is comprised of a 2.10% dividend yield and 5.40% (2.65% + 2.75%) growth rate. Such an assumption is totally unrealistic.

To bring some perspective to the growth rate assumed by witness Woolridge, forecast growth rates are available for the Value Line Composite of 996 industrial, retail and transportation companies that include 80 of Value Line's 99 industry groups and excludes financial services, utilities and non-North American companies.[3] In its forecast, Value Line projects growth for the Industrial Composite of 7.0% for earnings per share, 11.0% for dividends per share, 7.0% for book value per share, and 12.0% for percent retained to common equity. An average of these four growth rates is 9.25% (7.0% + 11.0% + 7.0% + 12.0% = 37.0% ÷ 4). When combined with the 2.1%

[3] Value Line Selection & Opinion (Part 2), dated November 1, 2013.

dividend yield published by Value Line, the return for the Value Line Composite is 11.35%, not 7.5% as witness Woolridge postulates.

Q. **Are there other reasons to believe that the 7.5% market return determined by witness Woolridge is unrealistic?**

A. Yes. A 7.5% overall return for the market is less than the DCF return that witness Woolridge calculates for his purportedly less risky electric group (see page 1 of Exhibit JRW-10). It is simply inconceivable that the return on the stock market as a whole is only 7.5% if the return for his electric utility proxy group is 8.75% and 9.00%. It is apparent that his total market return is incorrect.

Q. **Witness Woolridge also questions the need to further adjust the CAPM results for size differences. Please comment.**

A. Witness Woolridge's arguments (see pages 71-73) revolve around the purported distinction between regulated utilities and unregulated industrial companies. But, the Wong article employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because history shows that utilities generally have lower betas than many other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta.

Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns. Further, the article by Dr. Thomas Zepp presented research on water utilities that support a small firm effect in the utility industry.[4]

COMPARABLE EARNINGS

Q. **Witness Woolridge also ignores Comparable Earnings approach in his cost of equity analysis. Please comment.**

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Because the Comparable Earnings method is derived from a firm's overall performance (i.e., its average return), the approach blends returns on a variety of projects that have produced returns above and below the cost of capital during the measurement period.

[4] Zepp, Thomas M. (2002) "Utility stocks and the size effect: revisited". Economics and Finance Quarterly, 43, 578-582.

Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital. I have used this approach in connection with the other market models (i.e., DCF, Risk Premium, and CAPM) and the combined results of all methods fulfill established standards of a fair rate of return, i.e. namely, comparability and capital attraction. The Hope decision by the United States Supreme Court defined these requirements as follows:

> ...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

The Comparable Earnings approach satisfies the Supreme Court's comparability standard. In addition, the financial community has expressed the view[5] that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets.

THE COMMISSION'S PRIOR ASSESSMENT OF WITNESS WOOLRIDGE

Q **Is there any other information available to the Commission which it might consider in assessing witness Woolridge's recommended return on equity range of 8.75% and 9.00%?**

A. Yes. It would be informative for the Commission to consider how it has addressed Mr. Woolridge's rate of return testimony in prior electric utility cases.

[5] "Electric: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

Q Have you presented such a summary in this case?

A. Yes. Witness Woolridge has testified before this Commission in at least eight electric utility rate proceeding since 2005. Page 4 of Exhibit PRM-2, is a summary of those case showing the Docket No., witness Woolridge's recommended return on equity, the allowed return on equity approved by the Commission, and the differential between what witness Woolridge recommended and what the Commission concluded was proper.

From this exhibit four observations are readily apparent:

1. Over the course of a decade the equity markets have been influenced by a wide variety of fundamentals, yet witness Woolridge has recommended rates of return for Florida electric utilities within a narrow band of 100 basis point, i.e., between 8.75% and 9.75%.
2. The Commission has never accepted Dr. Woolridge's recommended ROE in an electric utility rate case.
3. The Commission has consistently authorized a ROE well above Dr. Woolridge's recommendation.
4. The average ROE allowance by the Commission has been 1.52% above Dr. Woolridge's recommendation.

SUMMARY

Q. **Please summarize your rebuttal testimony.**

A. There are three disputed cost of capital issues in this case. They focus on the appropriate cost for short term debt related to the future period when the rates are to be effective; the proper common equity ratio and resulting capital structure to be used to set rates, and FPUC's cost of equity.

The short term debt cost rate should be based upon a forecast rather than current interest rates. The only forecast before the Commission is revealed by a well-respected, independent source relied upon by investors. After summarily dismissing it as not being credible, witness Woolridge relied in part upon this forecast. The short term debt cost consistent with this forecast is 3.60% at the time of the Company's filing.

The Company's own capital structure should be used to set customer rates. These are the sources of capital actually employed to provide service. These are the sources of capital that have been invested by investors in the enterprise. Arbitrarily altering the overall return by using a hypothetical capital structure and imputing debt that is not being used to fund operations is unwarranted.

Witness Woolridge significantly understates the Company's cost of common equity. Rather, the Commission should use the evidence that I have developed, the returns previously authorized by the Commission and other state regulatory commissions, the types of returns that investors expect electric utilities to realize and its prior assessment of witness Woolridge's testimony to develop FPUC's allowed return on equity. That allowed return should be the 11.25% I recommended on direct and not the unreasonably low range suggested by Witness Woolridge.

Q. **Does this conclude your Prepared Rebuttal Testimony?**

A. Yes.

COMMISSIONER EDGAR: Any other matters?

MS. BROWNLESS: No, ma'am.

COMMISSIONER EDGAR: All right. Any other comments?

MS. KEATING: Just thank you, Commissioners. We appreciate it. We appreciate y'all helping us get to this point, and we're very appreciative.

COMMISSIONER EDGAR: All right. Then I will say as well thank you to my colleagues, to our staff, to the parties for their coordination and cooperation, and we are adjourned.

(Hearing adjourned at 1:45 p.m.)

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

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

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

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

DATED THIS 16th day of September, 2014.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734