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STEVE CRISAFULLI
Speaker of the House of Representatives

July 7, 2016

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 160021, 160061-EI, 160062-EI and 160088-EI

Dear Ms. Stauffer:

Please find enclosed for filing in the above referenced docket the Direct Testimony and Exhibits of **Helmuth Schultz, III.** This filing is being made via the Florida Public Service Commission's Web Based Electronic Filing portal.

If you have any questions or concerns; please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Charles J. Rehwinkel
Deputy Public Counsel

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power Company	Docket No. 160021-EI
In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company.	Docket No. 160061-EI
In re: 2016 depreciation and dismantlement study by Florida Power & Light Company.	Docket No. 160062-EI
In re: Petition for limited proceeding to modify and continue incentive mechanism, by Florida Power & Light Company.	Docket No. 160088-EI
______________________________________/	Filed: July 07, 2016

DIRECT TESTIMONY

OF

HELMUTH SCHULTZ III

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

Helmuth Schultz III

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 160021-EI, et al (consolidated)

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Helmuth W. Schultz III. My business address is 15728 Farmington Road, Livonia, Michigan 48154.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Senior Regulatory Analyst with Larkin & Associates, P.L.L.C.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, P.L.L.C.

A. Larkin & Associates, P.L.L.C., performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney generals, etc.). Larkin & Associates, P.L.L.C., has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including water and sewer, gas, electric and telephone utilities.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH DESCRIBES YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. Attached as Exhibit No.__(HWS-1), is a summary of my background, experience and qualifications.

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Larkin & Associates, P.L.L.C., was retained by the Florida Office of Public Counsel ("OPC") to review certain components of the rate increase requested by Florida Power & Light Company (the "Company" or "FPL"). Accordingly, I am appearing on behalf of the citizens of Florida ("Citizens") who are customers of FPL.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE THE ISSUES YOU WILL BE ADDRESSING IN THIS PROCEEDING.

A. I am addressing the appropriateness of the Company's proposed recovery of costs related to payroll, incentive compensation, benefits other than pensions and post-retirement benefits ("OPEB"), payroll taxes, tree trimming, pole inspections and Directors and Officers Liability ("DOL") Insurance premiums. I will also be addressing the level of the depreciation reserve surplus available in 2017 based on recommendations regarding cost estimates to be utilized in 2015 and 2016 that are considered excessive. I am also addressing the rate base impact from the change in the depreciation reserve surplus. Finally, I will address the Company's request regarding the continuation of the automatic storm recovery mechanism contained in the 2010 settlement agreement among parties that the Commission approved in Order No PSC-11-0089-S-EI and the 2013 settlement approved in Order No. PSC-13-0023-S-EI.

III. PAYROLL

Q. WHAT ISSUES DID YOU IDENTIFY DURING YOUR REVIEW THAT IMPACTED YOUR RECOMMENDATIONS REGARDING THE AMOUNT OF PAYROLL COST INCLUDED IN FPL'S 2017 PROJECTED TEST YEAR?

A. The Company has projected its payroll based on an increased number of employees using justification similar to its past two base rate filings. Based on what actually occurred subsequent to those filings, I determined that the Company's support for the amount of payroll included in O&M expense is insufficient.

Q. WHAT DID YOU REVIEW IN THE FILING THAT LED TO YOUR CONCERN RELATED TO THE LEVEL OF PAYROLL REQUESTED BY FPL IN THE TEST YEAR AND THE PROJECTED INCREASE IN EMPLOYEES?

A. I reviewed the Company testimony, Minimum Filing Requirement ("MFR") Schedule C-35 and responses to discovery. In my review of the testimony of FPL's witness Slattery, I noted that the witness addresses a perceived need for additional employees with similar justification to the justification offered in Docket No. 120015-EI. I became concerned that the projected employee complement would be excessive just as it has been in past rate filings. As shown on Company MFR Schedule C-35, the average number of employees for the historic years 2015 and 2014 was 8,836 and 8,847, respectively. The 2014 average of 8,847 was a decline from the average employee complement for 2013 of 9,506. This decline was reminiscent to the decline that was observed during and in the aftermath of, FPL's last rate case proceeding, Docket No. 120015-EI.

Here, in the Company's 2016 request, as shown on MFR Schedule C-35, payroll is based on an average of 9,087 employees in 2016, an average of 9,091 employees in 2017 and an average of 9,067 employees in 2018. The request for a significant increase of 255 employees from 2015 to 2017 follows the familiar path of this same issue in Docket No. 120015-EI. The similarities prompted a more in-depth review of what transpired after Docket No. 120015-EI ended with respect to employee levels to determine the reasonableness of the Company's request.

Q. DID YOU FIND THAT YOUR CONCERN WAS JUSTIFIED?

A. Yes. The Company's filing in Docket No. 120015-EI (MFR Schedule C-35), claimed that there would be an employee complement of 10,311 employees in 2012 and 10,147 employees in 2013. We now know that the actual average employee complement as shown on Exhibit No. HWS-2, Page 2, for 2013 was 9,506. That is a difference of 641 employees or a reduction of 6.32%. That is a material difference, corresponding to tens of millions of dollars in over-collected payroll costs. I then went back further and reviewed the Order PSC-10-0153-FOF-EI (page 143) in Docket No. 080677-EI, and saw the same pattern of conduct. There the Company requested 11,111 employees for the 2010 projected test year. We now know the average actual employee complement for 2010 was 10,195, a difference of 916 employees. FPL has established a pattern of conduct in which FPL requests far more employees than they really need and then reduces the employee complement or does not fill positions soon after the rate case order is final. Based on the Company's propensity to ask for significantly more employee positions than what it needs to operate efficiently, it is only appropriate to view the current request with skepticism. The Company did confirm in its response to OPC Interrogatory No. 1 in the current docket that 2017 employee positions were based on actual year-to-date 2015 figures adjusted for <u>forecasted</u> positions. As shown on Exhibit No. HWS-2, Page 2, the Company has established a pattern of not filling a significant number of its authorized positions. Specifically of concern, is the recent trend that variances between authorized and filled positions have noticeably widened. Based on the information included in the filing and the responses to discovery, it is obvious that once again the Company has significantly overstated the projected number of employees in its rate request. This overstatement will in turn again result in an excessive revenue requirement if the Commission accepts it.

Q. DID THE COMPANY ATTEMPT TO PROVIDE ANY JUSTIFICATION FOR THE INCREASE IN EMPLOYEES IN ITS REQUEST?

A. The Company provided testimony attempting to explain why they believe an increase in employees is required. In her direct testimony on pages 9-11, FPL Witness Slattery once again claims that the industry continues to face a severe shortage of skilled workers. She adds this is due to an aging workforce, skill gaps in the talent pool, and emerging technologies, with special emphasis on the nuclear employees. She further makes reference to some statistics indicating that 47% of the workforce will be eligible to retire in five years (this figure was 40% in Docket No. 120015-EI). She also suggests that the number of generation and power delivery employees eligible to retire in 5 years are slightly higher at 50%. These are the same claims that Witness Slattery provided in Docket No. 120015-EI, on the eve of FPL cutting its workforce by 6.42%.

Q. DO THE WORKFORCE DEMOGRAPHICS CONCERNS PUT FORTH BY THE COMPANY JUSTIFY INCREASING THE NUMBER OF EMPLOYEES IN THE COMPANY'S REQUEST?

A. No. As discussed earlier the Company made similar arguments in both Docket No. 080677-EI and Docket No. 120015-EI. Obviously, when exposed to the test of time, as I have shown above, these arguments fail to hold up.

Q. WHAT PRIMARY FACTOR SHOULD THE COMMISSION CONSIDER WHEN MAKING A DETERMINATION AS TO THE COMPANY'S PAYROLL REQUEST IN THIS FILING?

A. The primary factor the Commission should consider is the Company's history of making requests for an increased number of employees and the fact that in actuality the number of FPL employees has decreased every year since 2008. Also, as shown on Exhibit No. HWS-2, Page 2, when a comparison is made of FPL's number of actual employees to its authorized number, the Company has consistently shown that it does not hire at or near the level the Commission has authorized and upon which customer rates are established.

Another factor to be considered is that the Company has, when it filed its past two rate requests, consistently asked for more positions than was ultimately implicitly authorized. For example, the Company in Docket No. 080677-EI requested 11,111 employees for 2010 and 11,157 for 2011. As shown on Exhibit No. HWS-2, Page 2, the number of authorized employees for 2010 and 2011 was 10,627 and 10,250, respectively. The differences are significant (a reduction of 484 positions for2010 and a reduction of 907 positions for 2011) and would represent an excess revenue requirement of approximately $32.25 million based on the 2010 test year payroll expense. Furthermore, in Docket No. 120015-EI, the Company requested 10,147 positions for the projected 2013 test year, the actual average was 9,506 (a reduction of 641).

Q. HOW MANY OF THE REQUESTED 11,111 POSITIONS DID THE COMMISSION ALLOW IN DOCKET NO. 080677-EI?

A. The number was not specifically identified in the order. However, in Order No. PSC-10-0153-FOF-EI, the Commission referenced variance history based on actual to target. The Commission then elected to apply the 2007 variance of 2.08% in determining a disallowance to payroll expense. If one reduces the FPL requested 11,111 positions by 2.08% (or 231 positions), the result is an allowance of 10,880 positions for 2010, yet the actual 2010 average achieved was only 10,195. The Company, in essence collected from ratepayers compensation for 685 non-existent employees. Using the Commission adjustment in Docket No. 080677-EI, that would equate to an annual, excess revenue requirement of $45.6 million. In Docket No.

120015-EI, I recommended an employee complement of 9,766 for 2013. Even my estimate turned out to be overly optimistic as the actual average was 9,506. (Since that case was ultimately resolved through a contested stipulation, there is not a number specifically authorized by the Commission.) I believe it is very important that, when a decision is made in this case with respect to payroll, the Commission should recognize what the Company has historically claimed would occur, as opposed to what actually transpired. At least for its past two rate cases, FPL testimony has not come close to hitting the mark in its filed request for purposes of establishing its actual payroll. Therefore, an adjustment reducing the projected number of employees reflected in the current rate request is essential.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COMPANY'S REQUEST?

A. As shown on Exhibit No. HWS-2, Page 1 of 2, I am conservatively recommending that the number of estimated positions in the 2017 projected test year be reduced from 9,091 to 8,835. The figure of 8,835 is the 2015 average employee complement, although the December 2015 employee count was only 8,801. I consider this adjustment to be conservative (e.g. giving the company the benefit of the doubt) based on history. This reduction in employees reduces total payroll, excluding incentive compensation, by $26.766 million. Based on the Company's O&M allocation factor, this equates to a reduction in payroll expense of $17.743 million ($17.166 million jurisdictional).

Q. WHY DID YOU EXCLUDE INCENTIVE COMPENSATION FROM YOUR ADJUSTMENT?

A. Even though the Company has made an adjustment for executive incentive compensation removing at least some of the executive incentive compensation on a basis unrelated to the excessive staffing proposal, I am proposing a separate adjustment for employee incentive compensation. Including incentive compensation in the above payroll adjustment would result in an improper double counting of the dollars being adjusted.

IV. INCENTIVE COMPENSATION

Q. WHAT ANALYSIS DID YOU PERFORM TO EVALUATE THE COMPANY'S INCENTIVE COMPENSATION IN THIS CASE?

A. I analyzed FPL's testimony on this issue, relevant and available incentive plan information, the Commission's Order No. PSC-10-0153-FOF-EI from FPL's rate case in Docket No. 080677-EI, and the responses to discovery regarding payroll and incentive compensation in this current docket. In this case, FPL Witness Slattery stated on page 12 of her direct testimony that "FPL has excluded from its expense request the portions of executive and non-executive incentive compensation that were excluded by the 2010 Rate Order, Order No. PSC-10-0153-FOF." She explained that, even though FPL believes the expense is reasonable and properly recoverable in rates, this adjustment was made in an effort to narrow the items at issue in this rate case. This aspect of her testimony is essentially identical to the testimony provided in Docket No. 120015-EI.

Q. DID YOU HAVE AN ISSUE WITH THE COMPANY'S POSITION IN DOCKET NO. 120015-EI?

A. Yes. The issue was whether the Company followed Order No. PSC-10-0153-FOF-EI in Docket No. 080677-EI as it was written or as the adjustment to incentive compensation was calculated and intended to be implemented. I also had concerns with the purported goals that were incorporated in the incentive compensation process.

Q. DID THE COMPANY ADJUSTMENT TO REMOVE THE INCENTIVE COMPENSATION BASED ON THE ORDER IN DOCKET NO. 080677-EI NARROW THE ISSUES IN THIS RATE CASE?

A. Yes, but not sufficiently. To some degree, the issue was narrowed with respect to executive incentive compensation. However, a gap remains and I am recommending an adjustment be made for the employee incentive compensation. As shown on Exhibit No. HWS-3, I am recommending that the Company's 2017 O&M expense be reduced by $28.216 million ($27.298 million jurisdictional).

Q. HAVE YOU REVIEWED THE ADJUSTMENT MADE BY THE COMPANY?

A. Yes. FPL, has represented, in determining the revenue requirement for the 2017 projected test year and for the subsequent projected test year 2018, that $26.080 million and $26.644 million, respectively, were removed on a jurisdictional basis for executive incentive compensation.

Q. WHY DID YOU STATE THAT FPL "REPRESENTED" THAT AN EXECUTIVE INCENTIVE COMPENSATION ADJUSTMENT WAS MADE?

A. I am not convinced the amount identified is totally accurate. In response to OPC Interrogatory No. 139, the Company indicated the amount adjusted and stated that this adjustment was consistent with Order No. PSC-10-0153-FOF-EI in Docket No. 080677-EI. The response indicates the total Executive Incentive Compensation for 2017 and 2018 is $36.550 million and $37.112 million, respectively. In Docket No. 120015-EI, I questioned the O&M amounts represented to be the projected incentive compensation because the percentage allocated to O&M was significantly different from one year to the next. In Docket No. 120015-EI, the executive incentive compensation amounts identified for 2012 and 2013 were $55.111 million and $57.320 million, respectively. I have been analyzing rate filings for a long time and find the difference in the total amount to be significant. The Company did not provide an explanation as to how the number in this year's filing is so much lower than in the previous case. Without more explanation, the information provided by FPL would suggest that company executives took a material pay cut or that more of their compensation was shifted from incentive to base pay.

Q. IS THERE ANY OTHER INFORMATION THAT YOU REVIEWED THAT WOULD ADD TO YOUR CONCERN?

A. Yes. The response to OPC Production of Documents Request No. 3 provides the detailed work papers supporting the MFRs. The payroll detail for MFR Schedule C-35 indicates that for the projected test year 2017 the executive incentives amount is

$13.220 million and stock based compensation is $34.407 million for a total of $47.627 million. This is different from the executive incentive amount of $36.550 million as represented in the adjustment made by the Company in this case to comply with the Commission's prior order. I would also note that in the previous (2012) filing, the Company's executive incentive compensation also included what was identified as "Performance Incentive." I have not seen a reference to that in this filing, however I did observe in the Schedule C-35 detail for the MFR that in the years 2013 to 2015 there was a Performance Dollar award. I would further note that in reviewing the MFR detail for C-35 that the amount for Employee Incentives was listed as $80.282 million for 2017. The Company response to Staff Interrogatory No. 21 identifies total expensed and capitalized employee incentives to be $60.807 million. The Company did not provide an explanation for this discrepancy.

Q. IS IT POSSIBLE THAT THE INCENTIVE COMPENSATIONS PLANS HAVE CHANGED SIGNIFICANTLY FROM THOSE THAT EXISTED IN DOCKET NO. 120015-EI?

A. Based on my experience and my review of the information that was supplied, I do not believe they have changed significantly. The plan information I was able to review appears to be basically the same. The plan names and the limited documents provided in response to OPC Production of Document Request No. 7 appear to be similar, if not the same as what was provided in Docket No. 120015-EI. In fact, some of the limited plan information provided for this case is dated 2011 and 2012. The point is that the disclosed level of executive compensation is significantly less when compared to the last (2012) rate case filing and such a decline is something I have not seen before, at least to that level of significance. This is counterintuitive and should have been explained by FPL in its initial filing as it suggests that either there is executive compensation in the filing that has not been identified or that FPL executives have taken a massive pay cut which seems to run counter to FPL's position that it needs tools such as incentive compensation to attract certain qualifications in their employees.

Q. EARLIER YOU INDICATED THAT YOU SAW SOME OF THE INCENTIVE PLANS AND YOU JUST DISCUSSED SOME OF THE LIMITED PLAN INFORMATION PROVIDED. DID YOU REQUEST AND RECEIVE COPIES OF ALL THE PLAN DOCUMENTS?

A. Yes, I requested the complete plan documents; however I did not initially receive them all in my office. The Company's response to OPC Production of Document Request No. 7 provided 7 documents and indicated that another 10 documents that were considered "highly sensitive" would be made available for review at the law offices of the Radey Law Firm in Tallahassee. This response, in my experience, is highly unusual. On occasion a company has claimed confidentiality with respect to an incentive plan, yet I do not recall the plans being so *highly sensitive* that they had to be reviewed at the company's legal counsel's office. In conjunction with my review in 2012, I reviewed some, but not all, of the documents listed as highly sensitive and I did not have to travel to Florida to do an on-site review.

Q. DID YOU REVIEW ANY OF THE HIGHLY SENSITIVE DOCUMENTS IN THIS CASE?

A. Yes. OPC counsel went to the Radey Law offices and reviewed the documents and communicated to me the plan title and the basics of the plan. Some of the plans were redacted and provided for review.

Q. DID YOUR REVIEW OF THE VARIOUS HIGHLY SENSITIVE PLANS CHANGE YOUR POSITION WITH RESPECT TO THE QUALITY OF THE GOALS OR THE APPROPRIATENESS OF THE PLAN COSTS?

A. No. The information that was reviewed did not provide any support that the customer's reliability and/or safety was the primary focus of plan achievement.

Q. DID THE COMPANY ADJUST FOR NON-EXECUTIVE INCENTIVE COMPENSATION, AS PART OF ITS COMPLIANCE WITH ORDER NO. PSC-10-0153-FOF?

A. FPL, as part of what it presents as its compliance adjustment, reduced O&M expense $679,000 ($657,000 jurisdictional) in 2017 and $679,000 ($657,000 jurisdictional) in 2018, and represents that this is consistent with the Commission adjustment in Order No. PSC-10-0153-FOF. To put this in perspective, even assuming there is not an issue with what the order said and what the order did (discussed below), the adjustment for non-executive incentive compensation in Docket Nos. 086077-EI and 090130-EI (the 2008 rate case) was $5.661 million. This dramatic difference between the proposed adjustment and the 2008 rate case adjustment is counterintuitive and should have been explained by the Company in its initial filing as it suggests that there is non-executive compensation in the filing that has not been identified.

Q. IS THERE AN ISSUE WITH WHAT THE 2010 ORDER SAID AND WHAT THE ORDER DID IN DOCKET NOS. 086077-EI AND 090130-EI?

A. Yes. First, I would note that the adjustment made in the 2010 rate order from the 2008 rate case, Order No. PSC-10-0153-FOF, and the adjustment made by the Company in the current filing, after accounting for the omission (the exclusion or non-removal of the total non-executive dollars), appear to be consistent with the mechanics of the Commission's determination, with the noted exception to the level of dollars involved. As I pointed out in Docket No. 120015-EI, there is nevertheless a problem with the treatment of non-executive compensation. The problem is that, based upon my review of testimony and the Commission's prior decision, I believe there was an inadvertent oversight reflected in the Commission's 2010 order regarding what should have been included as part of the adjustment in that proceeding. The OPC witness' testimony on that issue was entitled "Non-Executive Incentive Compensation" and the questions discussed issues related to "Non-Executive Incentive Compensation"; however, the testimony dealt only with the non-executive long term incentive compensation. This was a different plan than the more costly, general non-executive type compensation plan. The Commission order also refers repeatedly to non-executive incentive compensation, which suggests the Commission was also under the impression that the OPC witness' recommended adjustment was similar to the executive incentive compensation cost adjustment recommendation that consisted of both cash-based incentives as well as stock-based incentives. Therefore, the non-executive compensation adjustment in Docket No. 080677-EI appears to have inadvertently omitted the cash-based portion of the non-executive incentive compensation when the decision was made with respect to what should have been adjusted. There was no explanation or rationale contained in the order as to why one component would be excluded from rates while the other would be included. That is why a significant difference exists in this filing when compared to the mechanics of the overall executive incentive compensation adjustment. The difference on a total Company basis in Docket No. 080677-EI amounted to approximately $52.966 million. Thus, the amount of non-executive incentive compensation at issue in this docket based on the intended adjustment in the 2010 order is, according to the response to Staff Interrogatory 21, is $60.807 million (O&M component of $40.309 million and Capital component of $20.498 million).

Q. HOW DOES ORDER NO. PSC-10-0153-FOF-EI FACTOR INTO YOUR RECOMMENDATION IN THIS CASE?

A. The Commission in Order PSC-10-0153-FOF decided that 100% of executive incentive compensation should be excluded from rates and "that 50 percent of the *non-executive incentive* compensation" should be excluded from O&M expense as "unreasonable". The justification for disallowing 50% (instead of the 100% disallowed for executives) was that the Commission was "hesitant to conclude that one hundred percent of the non-executive incentive compensation benefited only shareholders." I would concur with the Commission, provided the goals are set at a level that creates a true incentive to enhance performance. It should be noted, however, that in the Commission's Order in Docket Nos. 090079-EI, 090144-EI and 090145-EI (Progress Energy Florida's rate case – now Duke – and decided only 12 days before the FPL case) stated that 100% of all the incentive compensation (both executive and non-executive) should be disallowed. The adjustment I am proposing in the current docket is consistent with the Commission's Order in Docket No. 080677-EI as it applies to customer-related goals. The only difference between FPL's 2008 rate case and this case is that I have identified the portion of non-executive incentive compensation that was addressed and disallowed at the 50% level, but not explicitly identified in Docket No. 080677-EI. I think FPL's adjustment to remove only the non-cash portion of the non-executive incentive compensation is an erroneous implementation of the true intent of the 2010 rate order from Docket No. 080677-EI.

Q. WHEN IS ALLOWING SOME INCENTIVE COMPENSATION REASONABLE?

A. If goals are established that require improved customer service and performance as well as create cost savings as a condition of receiving payment, then justification exists for allowing a 50/50 sharing of the costs that will be incurred in achieving those stretch goals. It is important to distinguish between goals that require improvement and goals that simply allow incentive payments for performing at a level that is expected in day-to-day performance and/or a level that has previously been achieved. "Incentive" means to stimulate into action. There is no stimulation if goals are set at a level that does not require an effort to improve on past performance. For example, in the Progress

Energy Florida (PEF) rate case (Docket No. 090079-EI), I recommended full disallowance based on the fact that the plans were not designed to provide a quantifiable and/or tangible benefit to rate payers. Basically, the incentive plan was focused on paying added compensation for goals that were shareholder-oriented. As I noted earlier, the Commission agreed with my recommendation and disallowed the entire amount requested. Typically, if an employee plan is designed in a manner that would enhance performance that benefited ratepayers, I would recommend a 50/50 split. A properly designed employee incentive compensation plan will provide enhanced performance that benefits shareholders and ratepayers equally. The cost of such a plan then should be shared equally by shareholders and ratepayers.

Q. HOW DOES THAT DIFFER FROM THE EXCLUSION OF EXECUTIVE INCENTIVE COMPENSATION PLANS?

A. Executive plans are more focused on earnings. Therefore, more scrutiny has to be placed on executive compensation. Since executives are already highly compensated and the goals that are included in the executive plan are more focused on shareholder returns than customers, saddling the customers with these costs is not appropriate. In addition, the main purpose for an incentive plan for executives is to provide a means of deducting, for tax purposes, compensation that may not be deductible if paid strictly as base pay. More compensation is at issue and the bar should be set higher for any executive compensation to be included in rates.

Q. DID YOU REVIEW THE GOALS FOR THE FPL NON-EXECUTIVE INCENTIVE COMPENSATION PLAN?

A. I reviewed the goals and achievements over the past five years in an attempt to determine whether the goals are realistic and would stimulate improved performance. The information supplied on the goals and achievements in response to Staff Interrogatory No. 20 are in some cases generic, vague, very limited or otherwise inadequate. For example, the customer satisfaction goal, for residential and business components alike, for each of the five plan years was listed as "aggressive goal." That description is not very informative and does not provide any way to measure performance. With the exception of the 2015 residential component, the achievement was "beat goal." Again that identified achievement provides no measurement value. The exception for the 2015 residential satisfaction simply stated "Slightly missed goal." Measurement of satisfaction is generally based on surveys and should require that, as a level of satisfaction is achieved the applicable goal is increased the following year to a higher level. This would add an incentive for improvement. For FPL, there does not appear to be this process of "moving the goal posts" each year to incent additional improvement for the benefit of customers.

Another example of inadequate goal-setting is in the area of safety. In 2011, the Company achieved a .97 rating. This represents a ratio of recordable incidents per a set number of hours. In FPL's case, they are using 200,000 hours for measurement purposes. The lower the achieved number, the better. The goal for 2012 was set lower at .9 which creates an incentive to improve. The Company achieved that goal in 2012, and then set the next year's goal at a level that required improvement until goals were reset in 2015. The Company failed to achieve its 2014 goal and, instead of holding that goal at that level, the Company increased the allowable incident rate and made the goal easier to achieve. This suggests that, when compensation dollars are involved the Company is willing to relax the requirements to allow a better opportunity for achieving an incentive payout.

The service reliability component reflected similar results. In 2011, the Company failed to achieve the 13.4 goal for momentary interruptions with a 13.8 rating. However, instead of maintaining the goal at 13.4, the goal was relaxed to 13.9, a rating that would have been achieved if that were the goal in 2011. Here the lower the number the better for customer service. In 2012 the actual rating was 11.9 and the goal for 2013 was set at 12.3. Again the target for improvement was reduced instead of being advanced and set for improvement. It is interesting to note that in 2011 the goal for an incentive indicator labeled "Completion of base rate proceeding" was "fair outcome for customers and shareholders" and the Company indicated that the goal was achieved. To determine the payment of extra compensation to employees (a cost the Company is seeking from ratepayers) based on how the Company perceives the outcome of a base rate filing – in part for its shareholders – is not only insulting to ratepayers but also disingenuously subjective. While there is no explicit goal of this type provided in the documents I have reviewed, the mentality seems to pervade that goals are more often subjective and neither objectively established nor systematically and objectively enforced to yield customer benefits.

Finally, the Company's goals include financial metrics that if achieved are designed primarily to benefit shareholders. Reducing O&M means more income for shareholders and capital spending provides investors with more of a basis on which to earn a return. For example, budgeting \$62.2 million for vegetation maintenance and only spending \$58.5 million allows the Company to earn more. In my opinion, the goals, as depicted in the Company response to Staff Interrogatory 20, are limited at best. Likewise, easing the requirement, as discussed above, because a goal was not achieved does not provide an incentive for improvement. Instead, it suggests that the decision makers will do what is necessary to provide some assurance that the so-called at-risk pay is not really at risk. Based on the 2015 weighting of goals, the 40% financial metric should be assigned to shareholders and the remaining performance and so called customer goals should be split at best 50/50 between shareholders and ratepayers. The Company should be put on notice through ratemaking disallowances that, unless the goals are real goals that create an incentive to improve performance for the benefit of customers that the cost of the incentive plan(s) will be borne by shareholders.

Q. ARE YOU CONCERNED WITH THE GOALS THAT WERE NOT QUANTIFIED?

A. Yes. The determination of the success of goals is increased if the goal and the achievement are stated in numeric terms. This eliminates discretion and/or judgment as long as the goal is adhered to at the payout time. Measuring achievement without defined goals cannot be performed with precision, and the practice of not defining goals in numeric terms makes it impossible to track progress. For example, the goal of "aggressive" is subject to the evaluators' opinion as to what is aggressive and what is not.

Q. DOES YOUR RECOMMENDATION FOR SHARING THE NON-EXECUTIVE INCENTIVE COMPENSATION DIFFER FROM THE COMMISSION'S DETERMINATION IN ORDER NO. PSC-10-0153-EI-FOF?

A. No. In fact it is consistent with the determination in that order. The decision, as I read it, is focused on the sharing of benefits. The Commission stated it was hesitant to conclude that the plan benefitted only shareholders. That, in my opinion, means it was evaluating the flow of benefits when the decision was made to share the cost of non-executive incentive compensation equally. As I discussed earlier, for that sharing to take place, the evidence must establish that the goals used to determine whether payment will be made must be set at a level that creates a true incentive to perform at a higher level than previously achieved. FPL has consistently failed to set true incentive goals, which could serve as a basis for recommending a total disallowance.

Q. IS IT POSSIBLE THAT, BECAUSE SOME OR ALL OF INCENTIVE COMPENSATION IS DISALLOWED FOR RATEMAKING PURPOSES, COMPANIES WILL SIMPLY ELIMINATE THE PLAN AND INCREASE BASE PAY TO ACCOUNT FOR THE DIFFERENCE?

A. Some may say it is possible, however based on my experience I say it is improbable. In my four decades of analyzing rate cases, this has been a fairly common response by companies. I have never seen it happen. In fact, FPL Witness Slattery was asked this very question in the rebuttal phase of Docket No. 080677-EI[1]:

[1] Docket No. 080677-EI, Rebuttal Testimony & Exhibits of Kathleen Slattery; Page 21; filed August 6, 2009.

> Q. Would FPL need to reconsider restructuring its total compensation package *if any* incentive compensation expenses were excluded?
>
> A. Yes. FPL would need to consider reallocating total compensation and benefits so as to reduce performance-based compensation programs while raising base salaries and/or other traditional fixed-cost programs. This would raise costs to customers in the long run. Doing so would also negatively affect the Company's performance and impede the ability to compete in attracting and retaining the talent needed to deliver on commitments to customers. Penalizing utilities that shift from traditional fixed-cost programs to more flexible, performance-based programs would encourage inefficient program design that would negatively affect performance and harm customers.
>
> (Emphasis added)

It has been over six years since the decision in Docket No. 080677-EI, and FPL still has an incentive compensation plan.

Q. IS IT POSSIBLE THAT BY DISALLOWING COSTS RELATED TO INCENTIVE PLANS, THE COMPANY WILL SHIFT COMPENSATION TO BASE PAY?

A. I do not believe it is likely. First, I am not aware of any utility that does not have some form of incentive compensation plan. Incentive compensation is typically an issue in a proceeding. In some cases, like Docket No. 090079-EI, the entire amount has been disallowed and the Company continues to pay incentive compensation. Incentive compensation from its inception was not pay that was put at risk by shifting it from a base pay to a variable pay plan. Instead it was, in effect, just another form of compensation offered to employees, in addition to the employees' base pay.

Q. WILL THE DISALLOWANCE OF INCENTIVE COMPENSATION PUT THE COMPANY AT RISK BECAUSE ITS COMPENSATION PLAN IS NOT COMPETITIVE WITH OTHER UTILITIES?

A. No. It is a universal argument that a company measures the reasonableness of its compensation by comparing its employees' compensation with other operating entities. Companies typically argue that by disallowing the plan there is a risk that total compensation will not be competitive and they will not be able to attract and retain competent employees. In my experience, I have not observed any utility eliminate its incentive compensation plan despite having some or all of it disallowed for ratemaking purposes. Furthermore, compensation studies used by companies to justify the employee compensation are focused on total compensation. These studies may justify the total compensation paid to employees; however, to date I have not seen a study that makes a comparison of the various jurisdiction-specific allowance levels for incentive compensation as such is included in total compensation. Basically, the studies may provide some basis for paying employees, but the studies do not make any determination as to what is reasonable with regard to incentive compensation for purposes of establishing rates. Therefore, I believe this claim has no merit.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT?

A. As shown on Exhibit No. HWS-3, I began with the $60.807 million identified by the Company as employee incentive compensation. I excluded $24.323 million or 40% of the incentive compensation that is projected to be paid out based on the financial-related goals. That resulted in $36.484 million in incentive compensation that is projected to be paid out and it is associated with alleged customer goals. That $36.484 million was allocated 50/50 for an equal sharing of the supposed customer-related goals. The $42.565 million on line 7 ($24.323 million associated with financial goals plus $18.242 million representing the shareholders' half of the customer-related goal component) the total assigned to shareholders. To determine my adjustment, I applied the O&M allocation of 66.29% that was based on the Company's response to Staff Interrogatory 21. The result is an adjustment of $28.216 million ($27.298 million jurisdictional).

Q. IF YOU ARE CONCERNED ABOUT THE QUALITY OF THE GOALS, WHY DIDN'T YOU EXCLUDE MORE OR EVEN ALL OF THE INCENTIVE COMPENSATION?

A. I am attempting to align my adjustment as close as possible with the intent of Order No. PSC-10-0153-FOF. The financial goal adjustment is one change and, because some customer goals do exist, I am giving that some consideration as part of my overall recommendation. One *limited* example of a customer goal is the employee safety goal. The employee safety goal was achieved in 2012 with an OSHHA recordable of .75. The 2013 goal was then set at .73. In 2013 the .73 goal was achieved with an incident rate of .62 and the Company responded by setting the 2014 goal at .59. That is how the process should work. Unfortunately, when the Company failed to achieve the .59 goal in 2014, it went backwards and lowered the goal progress of the incentive process by easing the requirement in 2015 to .61. Based on what I have provided as evidence, the Commission could exclude all of the incentive compensation as was done in the Order in Docket Nos. 090079-EI, 090144-EI, and 090145-El.

V. EMPLOYEE BENEFITS

Q. ARE YOU MAKING ANY RECOMMENDATION WITH RESPECT TO EMPLOYEE BENEFITS?

A. Yes. I am recommending that employee benefit expense (excluding pensions and OPEB expense) be reduced by $2.681 million ($2.595 million jurisdictional). This calculation is shown on Exhibit HWS-4. My recommendation reflects the impact of my recommended payroll adjustment for the Company's excessive employee complement request.

Q. HAVE YOU MADE THE ADJUSTMENT SIMILAR TO YOUR PAYROLL ADJUSTMENT, WHERE YOU REDUCED THE BENEFITS ON A PER EMPLOYEE BASIS?

A. Yes. The adjustment for excess employees is shown on Exhibit No. HWS-4. My recommendation is a reduction to Account 926 of $2.681 million ($2.595 million on a jurisdictional basis) consistent with the benefit costs associated with the Company-projected 256 added positions that I have recommended be disallowed from the Company's projected employee complement, as discussed earlier.

VI. PAYROLL TAX EXPENSE

Q. WITH YOUR ADJUSTING PAYROLL IS THERE A FLOW THROUGH ADJUSTMENT TO PAYROLL TAX EXPENSE?

A. Yes. To the extent payroll is reduced, there is an associated reduction to payroll taxes that must be reflected. Thus, I am recommending a reduction of $1.152 million ($1.136 million jurisdictional) to payroll taxes to correspond with my payroll adjustment associated with the reduction in employees. I am also recommending a separate reduction of $1.775 million ($1.751 million jurisdictional) to payroll taxes to correspond with my adjustment to employee incentive compensation.

Q. HOW DID YOU DETERMINE YOUR PAYROLL TAX ADJUSTMENT?

A. Based on the Company's projected 2017 payroll tax dollars and payroll dollars as shown on MFR Schedule C-35, I calculated an effective payroll tax rate. The effective tax rate as calculated on Exhibit HWS-5 is 6.49%. I then applied that effective tax rate to my recommended adjustment to payroll expense of $17.743 million. The result is a payroll tax adjustment of $1.152 million ($1.136 million jurisdictional).

The second adjustment only factors in the FICA effective rate in my adjustment because the unemployment taxes would be factored into any general pay. The effective tax rate as calculated on Exhibit HWS-5 is 6.29%. I then applied that effective tax rate to my recommended adjustment to incentive compensation expense of $28.216 million. The result is a payroll tax adjustment of $1.775 million ($1.751 million jurisdictional).

VII. VEGETATION MANAGEMENT/HARDENING PLAN

Q. ARE YOU COMBINING THE DESCRIPTION OF VEGETATION MANAGEMENT WITH STORM HARDENING?

A. Yes. My identification of the vegetation management discussion is being linked with storm hardening because they are inextricably interrelated. FPL Witness Miranda in discussing the Company's storm hardening references vegetation management. When hardening of the system is being performed it encompasses not only poles and conductors, but it also includes vegetation, which is a primary cause of system damage. The Company in Docket No. 160061-EI (the Storm Docket), filed its storm hardening plan for approval contemporaneously with its base rate filing. In that filing, FPL witness Miranda attached as an Exhibit MBM-1(Storm), the FPL 2016-2018 Electric Infrastructure Storm Hardening Plan ("Plan"). Within the Plan, reference is made as to how the initiatives of storm hardening, vegetation management and pole inspections, can be reasonably expected to reduce future storm restoration costs compared to what they would be without those initiatives.

Q. PLEASE EXPLAIN HOW VEGETATION MANAGEMENT IS INTER-RELATED WITH STORM HARDENING.

A. The storm hardening that is discussed by the Company focuses on upgrading the system to be more storm-resilient. In conjunction with any effort to harden the system structurally, a utility must also address what causes damage to the system. Vegetation is a primary contributor to the damages to the utilities' transmission and distribution infrastructure that results from severe weather. In recent years, the east coast of the country has seen significant storm damage from hurricanes, tropical storms, lightning, wind (i.e. derecho type) and snow. Infrastructure can be directly impacted not only by wind and storms but it can also be indirectly impacted by broken tree limbs and falling trees. A number of utilities specifically include vegetation management as a major discussion piece of their storm hardening plan. This vegetation management plan includes cycle trimming but not the removal of danger and/or hazard trees. The classification as a "danger or hazard tree" is a term used by utilities for a purpose, that purpose is the trees are a danger and/or a hazard to the utilities infrastructure.

Q. WHAT ARE DANGER AND/OR HAZARD TREES?

A. A danger tree is a tree within and just outside the right of way that if it were to fall it could strike the line or pole within the right of way. A hazard tree is a danger tree but it is also either a diseased or damaged tree making it more susceptible to causing damage to infrastructure.

Q. WHAT DID YOU REVIEW IN DETERMINING WHETHER THE VEGETATION MAINTENANCE IS APPROPRIATE?

A. I reviewed Company storm and rate case testimony, its Plan and responses to discovery.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE 2017 PROJECTED TEST YEAR AND THE PROJECTED 2018 VEGETATION MANAGEMENT/HARDENING PLAN COSTS?

A. Yes. In reviewing the Company response to OPC Interrogatory No. 10, I noted that the Company has budgeted 15,100 miles of vegetation trimming for 2017 and 2018, the same number of miles budgeted for 2015. That suggests the Company is not anticipating increasing its trimming efforts. The response also indicates that the system, as of 2015, had 36,256 miles subject to trimming. That equates to a trim cycle of 2.4 years. Another important factor noted was the level of spending from both a budgeted and historical actual basis as shown in FPL's response to OPC Interrogatory No. 9. The information is summarized on Exhibit HWS-6 and it shows that over the past three years the Company did not expend what was budgeted for tree trimming. To the Company's credit, the miles actually trimmed exceeded the miles budgeted despite spending less than what was budgeted. Therefore, based on the current trim cycle, it is not unexpected that the cost could be less than anticipated and the miles trimmed more than anticipated. My analysis shows that it is appropriate to make an adjustment to reflect the expected and normal level of vegetation management/hardening expense.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COMPANY'S "PROJECTED COSTS?"

A. As shown on Exhibit No. HWS-6, I am recommending spending of $60.953 million, a reduction of $4.647 million ($4.647 million jurisdictional) to the Company's projected 2017 spending. This adjustment was determined by multiplying FPL's 2015 budgeted spending of $63.100 million by the budget-to-actual variance of 96.6% for the years 2013 through 2015. I then subtracted the result from the amount requested.

For 2018, I used the same process to calculate my projected spending but then escalated that by 2%. This resulted in a recommended spending of $62.172 million and a reduction of $7.428 million ($7.428 million jurisdictional) to the Company's projected 2018 spending.

Q. SHOULD THE COMMISSION BE CONCERNED THAT YOUR REDUCTION COULD IMPACT THE RELIABILITY OF THE SYSTEM SINCE YOUR RECOMMENDATION IS LESS THAN WHAT WAS EXPENDED IN 2015?

A. No. The Company spending for 2015 was based on 15,244 miles of trimming. The Company is budgeting based on 15,100 miles. The average cost per mile, with the exception of 2015, has declined from year to year and rightfully so. As I discussed earlier, the Company is on an approximate 2.4-year trim cycle. The benefit of being on an accelerated cycle is that it does not require the same level of aggressive trimming previously implemented. The declining average cost per mile is evidence of that. Company Witness Miranda states that FPL's approved vegetation plan is a three-year and six-year cycle[2]. The Company is ahead of the game and even with my recommended spending should be able to continue with that success.

Another factor to consider is that spending for vegetation management can vary from year to year, depending on the condition of the planned area for trimming, contractual pricing, and the actual miles trimmed. My projected cost is based on the historical average cost variance between what the Company budgeted and what was actually spent for trimming. The currently budgeted miles are essentially the same as

[2] Testimony of Manuel Miranda at page 11, lines 5-10.

the budgeted miles for the three years in my average and in my adjustment. I used the Company's 2015 budget for the same number of miles and simply applied the actual variance. The Company projection ignores the historical variance.

VIII. POLE INSPECTIONS/HARDENING PLAN

Q. ARE YOU RECOMMENDING A REDUCTION TO THE 2017 PROJECTED TEST YEAR POLE INSPECTION COSTS FOR THE SAME REASON THAT YOU RECOMMENDED THE VEGETATION MANAGEMENT/ HARDENING PLAN COST BE REDUCED?

A. Yes. In my review of the Company response to OPC Interrogatory No. 13, I noted that actual pole inspections expenses were below budget during the period 2012 through 2015, and this was despite the fact that the actual number of inspections exceeded the planned number of inspections. Similar to my position on the vegetation management issue, adjustments are appropriate for 2017 and 2018 O&M expense to reflect the historical budget to actual differences.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COMPANY'S PROJECTED POLE INSPECTION EXPENSE?

A. As shown on Exhibit No. HWS-7, I am recommending a reduction of $1.664 million ($1.663 million jurisdictional) to FPL's projected 2017 test year expense of $5.800 million. I calculated the adjustment by multiplying the Company request of $5.800 million by the budget-to-actual variance of 71.3% for the years 2013 through 2015 and subtracting the result from the amount requested by the Company.

A similar adjustment was made to reduce the Company's requested 2018 inspection cost of $5.900 million. The 2018 adjustment is a reduction of $1.693 million ($1.692 million jurisdictional).

IX. DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE PREMIUMS?

A. Yes. Directors and Officers Liability ("DOL") insurance protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. There is no question that DOL insurance, which FPL has elected to purchase, is primarily for the benefit of shareholders. Since shareholders are the primary beneficiary, they should be responsible for the costs associated with acquiring this coverage. The Company will inevitably argue that the cost is a necessary expense which protects ratepayers. Nevertheless, the cost of the premiums associated with acquiring DOL insurance, while considered to be a necessary business expense by many, is in reality a necessary business expense designed to protect shareholders from their past decisions. Notwithstanding that shareholders are the primary beneficiary, I am recommending that this business expense be shared equally between shareholders and rate payers.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING?

A. As shown on Exhibit HWS-8, I am recommending an estimated reduction to Account 925 of $1.391 million ($1.369 million jurisdictional) for the projected test year 2017 and an adjustment of $1.391 million ($1.346 million jurisdictional) for the subsequent projected test year 2018.

Q. WHY ARE YOU ESTIMATING THE COST FOR THE 2017 PROJECTED TEST YEAR AND THE SUBSEQUENT PROJECTED TEST YEAR of 2018?

A. In Interrogatory No. 37, Staff requested the Company to itemize each component of insurance expense for the test year, and provide comparative information for the years 2011-2015 and 2016 year to date. This request was verbatim, the same as OPC Interrogatory 60 in Docket No. 120015-EI. In Docket No. 120015-EI, I took exception to the DOL cost identified in the response and recommended an equal sharing of the cost. According to the response to OPC Interrogatory No. 60 in Docket No. 120015-EI, FPL had included $2,781,173 of expense in account 925 for DOL insurance (DOL) in the 2013 projected test year. Conveniently, the Company in the response to Staff Interrogatory No. 37 in the current docket lumped the DOL insurance in with "Liability Insurance Other." In addition, the Company failed to provide the test year insurance amounts as requested.

Q. HOW DO YOU KNOW THE DOL INSURANCE IS INCLUDED IN THE LIABILITY OTHER –INSURANCE AMOUNT?

A. By comparing the 2011 expense in the response to OPC Interrogatory 60 in Docket No. 120015-EI to the 2011 expense in the response to Staff Interrogatory No. 37 in Docket No. 160021-EI, I found costs to be the same or very close to being the same.

Q. HAVE YOU ADDRESSED THIS ISSUE IN PREVIOUS RATE CASES IN FLORIDA?

A. Yes. This issue was addressed in the Gulf Power Company rate case Docket No. 110138-EI. In that case, the Commission determined that the cost for DOL insurance should be shared equally between shareholders and ratepayers. In the PEF case (Docket No. 090079-EI[3]), the Commission allowed PEF to place one half the cost of DOL insurance in test year expenses noting that other jurisdictions make an adjustment for DOL insurance and that the Commission has disallowed DOL insurance in wastewater cases.

Q. WHAT IF THE COMMISSION HAD NOT DISALLOWED HALF THE COST IN THE GULF AND PEF DOCKETS, WHAT WOULD YOU THEN RECOMMEND IN THIS CASE?

A. I would still be recommending to the Commission that there be either a complete disallowance or at the very least an equal sharing, because the cost associated with DOL insurance benefits shareholders first and foremost. Unlike an unregulated entity, criteria exist for recovery of costs, such as prudence and benefit. The benefit of DOL insurance is the protection shareholders receive from directors' and officers' imprudent decision making. The benefit of this insurance clearly inures primarily to shareholders; some of whom generally are the parties initiating any suit against the directors and

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[3] See, Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc.

officers. The Commission's decisions on this question in the Gulf Power and PEF rate case dockets were fair, and those decisions should be followed in this Docket.

X. CAPITAL STORM HARDENING

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S CAPITAL STORM HARDENING COST?

A. Yes. As shown on my Exhibit HWS-9, I am recommending a reduction of $31.546 million to the projected test year 2017 and $45.335 million to the subsequent projected test year 2018. The Company has made significant strides in hardening the system and has expended more than planned during the years 2012 through 2015, however, I believe the projected increase in spending for 2016 through 2018 is overly optimistic.

Q. IF THE HISTORICAL SPENDING WAS TRADITIONALLY HIGHER THAN PLANNED WHY WOULD THE PLANNED SPENDING FOR 2016 THROUGH 2018 BE OVERLY OPTIMISTIC?

A. The cumulative capital spending in this area for the four years 2012 through 2015 that coincided with FPL's Stipulation and base rate freeze, totaled $1.001 billion. The proposed spending for just the two years 2016 and 2017 is projected to be $1.075 billion. That is $74 million more spending in half the time. The total spending for 2016 through 2018 of $1.943 billion is almost double the spending for the previous four years. That is significant and I do not share the Company's optimism for its capital storm spending levels.

Q. ARE YOU AWARE OF ANY INFORMATION THAT WOULD SUPPORT YOUR SKEPTICISM?

A. Yes. The Company's response to OPC Interrogatory No. 363 provided year to date capital expenditures through May 2016 along with forecasted 2016 and 2017 capital spending for storm hardening. The year to date May 2016 amount totaled $186 million, which when annualized totals $446 million. That $446 million is $25 million less than the 2016 forecasted capital spending of $471 million. It is also appropriate to keep in mind that with the storm season approaching that completing any makeup of the underspent amount in the second half of the year would be difficult.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENTS FOR 2017 AND 2018?

A. I utilized the ratio of the annualized May 2016 to the forecasted 2016, and applied that to the Company's forecasted 2017 and 2018 storm hardening capital costs. This calculation is shown on Exhibit No. HWS-9.

Q. DOES THIS ADJUSTMENT TO THE STORM HARDENING IMPACT ANY OTHER COSTS IN THE COMPANY'S REQUEST?

A. Yes. As shown on Exhibit No. HWS-9, I have calculated an adjustment to depreciation expense using a blended rate as recommended by Citizens Witness Pous and accordingly adjusted accumulated depreciation for the depreciation expense adjustment for the year. The adjustment to depreciation expense is a reduction of $856,000 and $1,231,000 for the years 2017 and 2018, respectively. The accumulated depreciation was one half of the annual expense to reflect an average for the year. The adjustment to accumulated depreciation is a reduction, increasing rate base, by $428,000 and $615,000 for the years 2017 and 2018, respectively.

XI. DEPRECIATION RESERVE SURPLUS

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR THE HISTORIC DEPRECIATION RESERVE SURPLUS THAT THE COMPANY APPLIED ENTIRELY TO THE 2016 YEAR?

A. Yes, to some extent I am making a recommendation. The Company has assumed that a 2015 unamortized amount of approximately $202 million will be utilized in 2016.[4] The amount included in 2016 is an estimate based on the projected cost of service for 2016. Based on the response to OPC Interrogatory No. 274, the actual December 2015 balance is $263 million. That leaves at least $61 million unaccounted for. The issue is the same as it was in Docket No. 120015-EI where the Company estimated that the reserve surplus would be fully utilized and not available to offset expenses in the projected test year. The response to OPC Interrogatory No. 108, in this docket, shows that the January 1, 2013 surplus reserve starting balance was $400 million. The surplus did not get utilized as the Company claimed it would be. As it was in Docket No. 120015-EI, the key word here is *estimated* and the assumption was it would be fully utilized. Clearly, since there is a balance remaining as of December 2015, the Company's assumption was wrong. The circumstances are very similar today. The amount for 2016 is not known and measurable, and is subject to change based on

[4] FPL Witness Barrett at page 34, lines 2-5.

changes in facts and/or assumptions that were employed in the forecasting of rate base, revenue and expenses for 2016. To simply assume the Company is correct could result in rates being set for 2017 with no means for accounting for an inaccurate estimate in 2016.

Q. HAVE YOU REQUESTED ANY 2016 INFORMATION TO SEE IF THE COMPANY ESTIMATE MAY BE REASONABLE?

A. Yes. In response to OPC Interrogatory No. 109, the Company indicated that it flowed back (credited depreciation expense) $176.409 million of the surplus reserve through March 2016. In reviewing the historical information for 2013 through 2015, the Company flowed back approximately $100,000,000 or more in the first quarter of each year. However, by the end of the respective years, the flow back changed. In 2013 the Company flowed back $155 million, in 2014 the Company reversed that flowback and restored $33 million to the surplus reserve because earnings did not allow for a flow back. In 2015 the Company flowed back only 15 million. In my opinion, the Company has overestimated the depreciation reserve surplus amortization requirement for 2016 by overstating expenses. Based on the response to OPC Interrogatory No. 108, the Company planned a flow back of $184 million for 2013 yet it only flowed back $155 million. For 2014, the Company estimated a $16 million reversal of the flow back and it actually was $33 million. Finally, the 2015 estimate was a flow back of $81 million while the actual flow back was $15 million. Similar results occurred during the years 2010 through 2012. The use of estimates will present issues and the fact remains that the Company estimate for 2016 is not known and measurable.

Q. DIDN'T THE STIPULATION IN DOCKET NO. 120015-EI CONTEMPLATE THE COMPLETE AMORTIZATION OF THE RESERVE SURPLUS BY 2016?

A. Yes. However, the Stipulation also stated that FPL may not amortize an amount that would result in FPL achieving a return on equity greater than 11.50%. The Company achieved a return on equity of 11.50% in two of the last three years. It is probable based on those results that the Company could achieve an 11.50% return on equity in 2016. This is especially true if some of the projected costs that are being adjusted in the 2017 projected test year are also adjusted in 2016.

Q. ARE THERE SOME SPECIFIC COSTS THAT YOU BELIEVE WOULD IMPACT THE AMOUNT OF THE DEPRECIATION RESERVE SURPLUS THAT WOULD BE REQUIRED IN 2016?

A. Yes. As discussed in detail, FPL has overestimated payroll because it assumed an excessive employee complement in 2017. Similarly, there are other estimated costs such as tree trimming, pole inspections, DOL insurance and incentive compensation that are overstated, as well as employee benefits and payroll taxes.

Q. HAVE YOU CALCULATED ADJUSTMENTS TO THE 2016 PROJECTED COSTS THAT WOULD RESULT IN AN INCREASED AMOUNT OF DEPRECIATION RESERVE SURPLUS AVAILABLE TO OFFSET COSTS IN 2017?

A. No specific adjustments have been determined. However, any O&M adjustment made to the 2017 projected test year could be applied to the 2016 year since the Company

2016 amount is just a projection. That said, I do not recommend that any unused depreciation reserve surplus that was initially established in Order No. PSC-10-0153-FOF-EI, be applied as a reduction to the Company's projected 2017 cost of service.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO ANY UNUSED SURPLUS?

A. The initial order establishing the $894.6 million reserve established a four-year amortization period and that was changed by the Stipulation and Order No. PSC-13-0023-S EI. That Order stated that the amount was to be amortized by the end of 2016 unless earnings exceeded 11.50%. The appropriate return of the over collection from ratepayers has dragged on well beyond a reasonable point in time. Therefore, I recommend that any unused surplus remaining as of December 31, 2016 be refunded to ratepayers over no more than a two-year period. Additionally, I recommend that because there is $61 million more in the reserve as of January 1, 2016 than the Company estimated and given the fact that since the reserve was established the amortization over a six year period has averaged $105.267 million, the 2016 earnings and surplus requirement be the subject of a review to assure that ratepayers receive what they are entitled to. Hypothetically, with a $263 million balance at the beginning of the year and based on the historical trend, there could be over $150 million of unused surplus reserve. Given the fact that ratepayers have waited beyond the initial time frame set for the return of funds they advanced to the Company, ratepayers should be entitled to some verification of how the remaining $263 million was used or remains unused and subject to refund.

XII. STORM RECOVERY MECHANISM

Q. HAVE YOU REVIEWED THE TESTIMONY OF COMPANY WITNESS DEWHURST REGARDING STORM COST RECOVERY?

A. Yes. Company Witness Dewhurst states that, while the Company preferred the recovery method that allows for an annual accrual to provide for a storm reserve level that would accommodate most storms and still allow the Company to seek recovery of storm costs that exceed the storm reserve, however, the Company is willing to continue to recover prudently incurred storm costs under the framework prescribed by the 2010 Rate Settlement and continued by the 2012 Rate Settlement.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S TESTIMONY?

A. The current framework prescribed by the 2010 Rate Settlement and continued by the 2012 Rate Settlement is sufficient with some exceptions. As for the previous recovery system, I am of the opinion it also would work, as long as safeguards are in place.

Q. WOULD YOU EXPLAIN WHAT EXCEPTIONS YOU HAVE WITH THE CURRENT FRAMEWORK?

A. Yes. The Order approving the stipulation states that "FPL would not be precluded from petitioning the Commission to seek recovery of costs associated with any storms."[5] That, in my opinion, could be what is referred to as a Pandora's Box. The reference to "any storm" is a concern. Storms happen and are common to all companies and to ratepayers. No one reimburses ratepayers for storm costs by means of a Commission

[5] Order No. PSC-13-0023-S-EI at page 3.

order, the ratepayers must incur a cost for insurance to protect their homes and ratepayers are responsible for costs not covered by insurance. The Company should have the recovery subject to a level that is set for major storms and not just any storm. I am aware that the OPC has agreed to similar language for all 5 investor-owned electric utilities and that the intent in the negotiated agreements is that the recovery under the provision is limited to major, named storms as defined by the National Hurricane Center. If this is the first occasion where the Commission will be adopting the provision as its own, I would recommend that the language in the final order clarify that recovery is so limited.

Q. ARE THERE OTHER CONCERNS WITH THE CURRENT STORM RECOVERY FRAMEWORK?

A. Yes. In Attachment A to the Order approving the 2012 Settlement Agreement, at page 5, it states "The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply <u>any</u> form of earnings test or measure or consider previous or current base rate earnings or level of theoretical depreciation reserve."[6] The word "any" concerns me. I understand that the intent is that "rate case" type inquiries were intended to preclude earnings based limitations on full recovery of costs and reserve replenishment. Likewise the parties would be precluded from suggesting other cost savings (unrelated to the storm damage) offsets to limit full recovery. The intent was not and should not

[6] Order No. PSC-13-0023-S-EI, Attachment A at page 5, subpart (c).

be memorialized by the language in the proposal to limit legitimate inquiry into the reasonableness and prudence of the costs that the company claims to have incurred in storm damage repair and restoration activities. By itself, the plain wording of the proposal suggests the Company has a blank check and what FPL says is storm related gets classified as such without any questions asked. I urge the Commission to ensure that the going-forward understanding is that a full opportunity to test and challenge costs will be provided in the time that is needed since the company will be allowed to receive expedited interim recovery of costs.

Q. WHAT SAFEGUARDS SHOULD EXIST IF THE COMPANY WERE TO RETURN THE PREVIOUS RECOVERY SYSTEM?

A. If annual accrual is to be used, those accruals should be based on historical information specific to the Company. Some of the storm analysis done for the companies, in the past used a model that evaluates storms over a set period of time and included a very wide geographic area. Factoring in a geographic area that is outside of the company's specific customer service area is not appropriate. Factoring in hurricanes that did not impact the company's service territory is not appropriate. Also a major consideration is the Company's intensive storm hardening program. This should be factored in because ratepayers have paid for this hardening and not factoring the hardening in would be like paying for insurance to mitigate storm costs but not being able to collect on it. Another major factor that should be factored in is establishing a threshold for what is a major storm and that threshold should be the shareholders responsibility. If a change were to be implemented these are suggestions that should be considered, I would also suggest that all parties be involved in a dialogue that would make sure that when the unforeseen storms that have a major impact do occur that shareholders and ratepayers receive a fair consideration as to what costs should be borne by whom. Ratepayers should not be the sole source of funding for storm costs, as shareholders are aware that there is a risk in making an investment and unlike non-regulated companies utility shareholders have been compensated for that risk in the established return on equity.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes it does.

CERTIFICATE OF SERVICE

Docket No. 160021-EI, et al (consolidated)

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony & Exhibits of Helmuth Schultz, III has been furnished by electronic mail to the following parties on this 7th day of July, 2016:

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Deputy Public Counsel

QUALIFICATIONS OF HELMUTH W. SCHULTZ, III

Mr. Schultz received a Bachelor of Science in Accounting from Ferris State College in 1975. He maintains extensive continuing professional education in accounting, auditing, and taxation. Mr. Schultz is a member of the Michigan Association of Certified Public Accountants

Mr. Schultz was employed with the firm of Larkin, Chapski & Co., C.P.A.s, as a Junior Accountant, in 1975. He was promoted to Senior Accountant in 1976. As such, he assisted in the supervision and performance of audits and accounting duties of various types of businesses. He has assisted in the implementation and revision of accounting systems for various businesses, including manufacturing, service and sales companies, credit unions and railroads.

In 1978, Mr. Schultz became the audit manager for Larkin, Chapski & Co. His duties included supervision of all audit work done by the firm. Mr. Schultz also represents clients before various state and IRS auditors. He has advised clients on the sale of their businesses and has analyzed the profitability of product lines and made recommendations based upon his analysis. Mr. Schultz has supervised the audit procedures performed in connection with a wide variety of inventories, including railroads, a publications distributor and warehouser for Ford and GM, and various retail establishments.

Mr. Schultz has performed work in the field of utility regulation on behalf of public service commission staffs, state attorney generals and consumer groups concerning regulatory matters before regulatory agencies in Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Kentucky, Kansas, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, Rhode Island, Texas, Utah, Vermont and Virginia. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on numerous occasions.

Partial list of utility cases participated in:

U-5331	Consumers Power Co. Michigan Public Service Commission
Docket No. 770491-TP	Winter Park Telephone Co.

	Florida Public Service Commission
Case Nos. U-5125 and U-5125(R)	Michigan Bell Telephone Co. Michigan Public Service Commission
Case No. 77-554-EL-AIR	Ohio Edison Company Public Utility Commission of Ohio
Case No. 79-231-EL-FAC	Cleveland Electric Illuminating Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Refunds Michigan Public Service Commission
Docket No. 820294-TP	Southern Bell Telephone and Telegraph Co. Florida Public Service Commission
Case No. 8738	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
82-165-EL-EFC	Toledo Edison Company Public Utility Commission of Ohio
Case No. 82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
Docket No. 830012-EU	Tampa Electric Company, Florida Public Service Commission
Case No. ER-83-206	Arkansas Power & Light Company, Missouri Public Service Commission
Case No. U-4758	The Detroit Edison Company - (Refunds), Michigan Public Service Commission
Case No. 8836	Kentucky American Water Company,

	Kentucky Public Service Commission
Case No. 8839	Western Kentucky Gas Company, Kentucky Public Service Commission
Case No. U-7650	Consumers Power Company - Partial and Immediate Michigan Public Service Commission
Case No. U-7650	Consumers Power Company - Final Michigan Public Service Commission
U-4620	Mississippi Power & Light Company Mississippi Public Service Commission
Docket No. R-850021	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. R-860378	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. 87-01-03	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 87-01-02	Southern New England Telephone State of Connecticut Department of Public Utility Control
Docket No. 3673-U	Georgia Power Company Georgia Public Service Commission
Docket No. U-8747	Anchorage Water and Wastewater Utility Alaska Public Utilities Commission
Docket No. 8363	El Paso Electric Company The Public Utility Commission of Texas

Docket No. 881167-EI	Gulf Power Company Florida Public Service Commission
Docket No. R-891364	Philadelphia Electric Company Pennsylvania Office of the Consumer Advocate
Docket No. 89-08-11	The United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. 9165	El Paso Electric Company The Public Utility Commission of Texas
Case No. U-9372	Consumers Power Company Before the Michigan Public Service Commission
Docket No. 891345-EI	Gulf Power Company Florida Public Service Commission
ER89110912J	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 890509-WU	Florida Cities Water Company, Golden Gate Division Florida Public Service Commission
Case No. 90-041	Union Light, Heat and Power Company Kentucky Public Service Commission
Docket No. R-901595	Equitable Gas Company Pennsylvania Consumer Counsel
Docket No. 5428	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 90-10	Artesian Water Company Delaware Public Service Commission
Docket No. 900329-WS	Southern States Utilities, Inc.

	Florida Public Service Commission
Case No. PUE900034	Commonwealth Gas Services, Inc. Virginia Public Service Commission
Docket No. 90-1037* (DEAA Phase)	Nevada Power Company - Fuel Public Service Commission of Nevada
Docket No. 5491**	Central Vermont Public Service Corporation Vermont Department of Public Service
Docket No. U-1551-89-102	Southwest Gas Corporation - Fuel Before the Arizona Corporation Commission
	Southwest Gas Corporation - Audit of Gas Procurement Practices and Purchased Gas Costs
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 5532	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 910890-EI	Florida Power Corporation Florida Public Service Commission
Docket No. 920324-EI	Tampa Electric Company Florida Public Service Commission
Docket No. 92-06-05	United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. C-913540	Philadelphia Electric Co. Before the Pennsylvania Public Utility Commission

Docket No. 92-47	The Diamond State Telephone Company Before the Public Service Commission of the State of Delaware
Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation (Supplemental) State of Connecticut Department of Public Utility Control
Docket No. 93-08-06	SNET America, Inc. State of Connecticut Department of Public Utility Control
Docket No. 93-057-01**	Mountain Fuel Supply Company Before the Public Service Commission of Utah
Docket No. 94-105-EL-EFC	Dayton Power & Light Company Before the Public Utilities Commission of Ohio
Case No. 399-94-297**	Montana-Dakota Utilities Before the North Dakota Public Service Commission
Docket No. G008/C-91-942	Minnegasco Minnesota Department of Public Service
Docket No. R-00932670	Pennsylvania American Water Company Before the Pennsylvania Public Utility Commission
Docket No. 12700	El Paso Electric Company Public Utility Commission of Texas

Case No. 94-E-0334	Consolidated Edison Company Before the New York Department of Public Service
Docket No. 2216	Narragansett Bay Commission On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Case No. PU-314-94-688	U.S. West Application for Transfer of Local Exchanges Before the North Dakota Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 95-03-01	Southern New England Telephone Company State of Connecticut Department of Public Utility Control
Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 96-01-26**	Bridgeport Hydraulic Company State of Connecticut Department of Public Utility Control
Docket Nos. 5841/ 5859	Citizens Utilities Company Before Vermont Public Service Board

Docket No. 5983	Green Mountain Power Corporation Before Vermont Public Service Board
Case No. PUE960296**	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-03493A-98-0705*	Black Mountain Gas Division of Northern States Power Company, Page Operations Before the Arizona Corporation Commission
Docket No. 98-10-07	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-01-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-04-18	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 99-09-03	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 980007-0013-003	Intercoastal Utilities, Inc. St. John County - Florida
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah

Docket No. 6332 **	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. G-01551A-00-0309	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 6460**	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 01-05-19 Phase I	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket No. 010949-EI	Gulf Power Company Before the Florida Office of the Public Counsel
Docket No. 2001-0007-0023	Intercoastal Utilities, Inc. St. Johns County - Florida
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket Nos. R. 01-09-001 I. 01-09-002	Verizon California Incorporated Before the California Public Utilities Commission
Docket No. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-04	United Illuminating Company State of Connecticut Department of Public Utility Control

Docket Nos. 5841/ 5859	Citizens Utilities Company Probation Compliance Before Vermont Public Service Board
Docket No. 6120/6460	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 020384-GU	Tampa Electric Company d/b/a/ Peoples Gas System Before the Florida Public Service Commission
Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 6914	Shoreham Telephone Company Before the Vermont Public Service Board
Docket No. 04-06-01	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket Nos. 6946/6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42**	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 050045-EI**	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 050078-EI**	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 05-03-17	The Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control

Docket No. 05-06-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. A.05-08-021	San Gabriel Valley Water Company, Fontana Water Division Before the California Public Utilities Commission
Docket NO. 7120 **	Vermont Electric Cooperative Before the Vermont Public Service Board
Docket No. 7191 **	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 06-035-21 **	PacifiCorp Before the Public Service Commission of Utah
Docket No. 7160	Vermont Gas Systems Before the Vermont Public Service Board
Docket No. 6850/6853 **	Vermont Electric Cooperative/Citizens Communications Company Before the Vermont Public Service Board
Docket No. 06-03-04** Phase 1	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control
Application 06-05-025	Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company Before the California Public Utilities Commission
Docket No. 06-12-02PH01**	Yankee Gas Company State of Connecticut Department of Public Utility Control
Case 06-G-1332**	Consolidated Edison Company of New York, Inc.

	Before the NYS Public Service Commission
Case 07-E-0523	Consolidated Edison Company of New York, Inc. Before the NYS Public Service Commission
Docket No. 07-07-01	Connecticut Light & Power Company Connecticut Department of Public Utility Control
Docket No. 07-035-93	Rocky Mountain Power Company Before the Public Service Commission of Utah
Docket No. 07-057-13	Questar Before the Public Service Commission of Utah
Docket No. 08-07-04	United Illuminating Company Connecticut Department of Public Utility Control
Case 08-E-0539	Consolidated Edison Company of New York, Inc. Before the NYS Public Service Commission
Docket No. 080317-EI	Tampa Electric Company Before the Florida Public Service Commission
Docket No. 7488**	Vermont Electric Cooperative, Inc. Before the Vermont Public Service Board
Docket No. 080318-GU	Peoples Gas System Before the Florida Public Service Commission
Docket No. 08-12-07***	Southern Connecticut Gas Company Connecticut Department of Utility Control
Docket No. 08-12-06***	Connecticut National Gas Company Connecticut Department of Utility Control
Docket No. 090079-EI	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 7529 **	Burlington Electric Company

	Before the Vermont Public Service Board
Docket No. 7585****	Green Mountain Power Corporation Alternative Regulation Before the Vermont Public Service Board
Docket No. 7336****	Central Vermont Public Service Company Alternative Regulation Before the Vermont Public Service Board
Docket No. 09-12-05	Connecticut Light & Power Company Connecticut Department of Utility Control
Docket No. 10-02-13	Aquarion Water Company of Connecticut Connecticut Department of Utility Control
Docket No. 10-70	Western Massachusetts Electric Company Massachusetts Department of Public Utilities
Docket No. 10-12-02	Yankee Gas Services Company Connecticut Department of Utility Control
Docket No. 11-01	Fitchburg Gas & Electric Light Company Massachusetts Department of Public Utilities
Case No.9267	Washington Gas Light Company Maryland Public Service Commission
Docket No. 110138-EI	Gulf Power Company Before the Florida Public Service Commission
Case No.9286	Potomac Electric Power Company Maryland Public Service Commission
Docket No. 120015-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 11-102***	Western Massachusetts Electric Company Massachusetts Department of Public Utilities

Docket No. 8373****	Green Mountain Power Company Alternative Regulation Before the Vermont Public Service Board
Docket No. 110200-WU	Water Management Services, Inc. Before the Florida Public Service Commission
Docket No. 11-102/11-102A	Western Massachusetts Electric Company Massachusetts Department of Public Utilities
Case No.9311	Potomac Electric Power Company Maryland Public Service Commission
Case No.9316	Columbia Gas of Maryland, Inc. Maryland Public Service Commission
Docket No. 130040-EI**	Tampa Electric Company Before the Florida Public Service Commission
Case No.1103	Potomac Electric Power Company Public Service Commission of the District of Columbia
Docket No. 13-03-23	Connecticut Light & Power Company Connecticut Public Utility Regulatory Authority
Docket No. 13-06-08	Connecticut Natural Gas Corporation Connecticut Public Utility Regulatory Authority
Docket No. 13-90	Fitchburg Gas & Electric Light Company Massachusetts Department of Public Utilities
Docket No. 8190**	Green Mountain Power Company Before the Vermont Public Service Board
Docket No. 8191**	Green Mountain Power Company Alternative Regulation Before the Vermont Public Service Board

Case No.9354**	Columbia Gas of Maryland, Inc. Maryland Public Service Commission
Docket No.2014-UN-132**	Entergy Mississippi Inc. Mississippi Public Service Commission
Docket No. 13-135	Western Massachusetts Electric Company Massachusetts Department of Public Utilities
Docket No. 14-05-26	Connecticut Light & Power Company Connecticut Public Utility Regulatory Authority
Docket No. 13-85	Massachusetts Electric Company and Nantucket Electric Company D/B/A/ as National Grid Massachusetts Department of Public Utilities
Docket No. 14-05-26RE01***	Connecticut Light & Power Company Connecticut Public Utility Regulatory Authority
Docket No.2015-UN-049**	Atmos Energy Corporation Mississippi Public Service Commission
Case No.9390	Columbia Gas of Maryland, Inc. Maryland Public Service Commission
Docket No. 15-03-01***	Connecticut Light & Power Company Connecticut Public Utility Regulatory Authority
Docket No. 15-03-02***	United Illuminating Company Connecticut Department of Public Utility Control
Case No.1135***	Washington Gas Public Service Commission of the District of Columbia

* Certain issues stipulated, portion of testimony withdrawn.
** Case settled.
*** Assisted in case and hearings, no testimony presented
**** Annual filings reviewed and reports filed with Board.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

2017 & 2018 Employee Adjustments

Line No.	Description	Per Company ($000's)	Per OPC ($000's)	Reference
1	Total Employees 2017	9,091	9,091	a
2	Employee Adjustment		(256)	Testimony
3	Adjusted Employee Level	9,091	8,835	
4	Total Payroll 2017	1,077,342	1,077,342	a, b
5	Executive Incentive Compensation	(46,556)	(46,556)	b
6	Executive Performance Incentive Compensation	0	0	b
7	Employee Incentive Compensation	(80,282)	(80,282)	b
8	Total Payroll Excluding Incentive Compensation	950,503	950,503	
9	Average Pay Per Employee Excluding Incentive Pay	104.554	104.554	L.8/L.3
10	Gross Payroll Adjustment		(26,766)	L.2 x L. 9
11	Expense Factor		66.29%	Testimony
12	O&M Adjustment 2017		(17,743)	L.10 x L. 11
13	Jurisdictional Allocation		0.967454	c
14	Jurisdictional O&M Adjustment 2017		(17,166)	L.12 x L. 13

Source: (a) Company MFR Schedule C-35.
(b) Company response to OPC Production of Documents No. 3.
(c) Company MFR Schedule C-1.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

Employee Analysis

Docket No. 160021-EI
Exhibit No. HWS-2
Payroll Adjustments

Line No.		Exempt	Non-Exempt	Actuals Union	Temporary	Total	Authorized	Variance
1	2004	4,227	2,608	3,212	60	10,107	10,338	2.23%
2	2005	4,319	2,619	3,203	84	10,225	10,408	1.76%
3	2006	4,407	2,679	3,216	88	10,390	10,552	1.54%
4	2007	4,517	2,660	3,271	109	10,557	10,768	1.96%
5	2008	4,632	2,619	3,379	82	10,711	10,994	2.57%
6	2009	4,607	2,633	3,323	64	10,627	11,072	4.02%
7	2010	4,451	2,500	3,173	71	10,195	10,627	4.07%
8	2011	4,420	2,339	3,065	137	9,961	10,250	2.82%
9	2012						10,311	
10	2013	4,467	1,802	3,066	171	9,506	10,147	6.32%
11	2014	4,235	1,576	2,901	135	8,847		
12	2015	4,344	1,425	2,920	146	8,835		
13	Jan-16					0	8,990	
14	Feb-16					0	9,007	
15	Mar-16					0	9,017	
16	Apr-16					0	9,024	
17	May-16					0	9,088	
18	Jun-16					0	9,145	
19	Jul-16					0	9,185	
20	Aug-16					0	9,167	
21	Sep-16					0	9,126	
22	Oct-16					0	9,116	
23	Nov-16					0	9,092	
24	Dec-16					0	9,082	
25	Average						9,087	
				Projected				
26	Jan-17	4,647	1,367	2,959	105		9,078	
27	Feb-17	4,649	1,381	2,958	104		9,092	
28	Mar-17	4,651	1,397	2,954	86		9,088	
29	Apr-17	4,638	1,407	2,959	66		9,070	
30	May-17	4,634	1,406	2,948	133		9,121	
31	Jun-17	4,645	1,391	2,947	165		9,148	
32	Jul-17	4,649	1,377	2,953	176		9,155	
33	Aug-17	4,648	1,374	2,955	154		9,131	
34	Sep-17	4,646	1,368	2,955	117		9,086	
35	Oct-17	4,635	1,362	2,956	114		9,067	
36	Nov-17	4,631	1,357	2,953	100		9,041	
37	Dec-17	4,621	1,343	2,954	96		9,014	
38	Average						9,091	

Source: Lines 1-5 are from Company response to OPC IR 34 Amended in Docket No. 120015-EI.
Line 6-8 are from Company response to OPC IR 33 Amended in Docket No. 120015-EI.
Lines 10-37 are from Company response to OPC POD 3 in Docket No. 160021-EI
Line 9 is from MFR Schedule C-35 in Docket No. 120015-EI.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

2018 Employee Adjustment

Docket No. 160021-EI
Exhibit No. HWS-2
Payroll Adjustments

Line No.		$000's Per Company	Per OPC	Reference
1	Total Employees 2018	9,067	9,067	a
2	Employee Adjustment		(232)	Testimony
3	Adjusted Employee Level	9,067	8,835	
4	Total Payroll 2018	1,103,164	1,103,164	a
5	Executive Incentive Compensation	(51,530)	(51,530)	b
6	Executive Performance Incentive Compensation	0	0	b
7	Employee Incentive Compensation	(77,066)	(77,066)	b
8	Total Payroll Excluding Incentive Compensation	974,568	974,568	
9	Average Pay Per Employee Excluding Incentive Pay	107.485	107.485	L.8/L.3
10	Gross Payroll Adjustment		(24,937)	L.2 x L. 9
11	Expense Factor		66.29%	Testimony
12	O&M Adjustment 2018		(16,530)	L.10 x L. 11
13	Jurisdictional Allocation		0.964177	c
14	Jurisdictional O&M Adjustment 2018		(15,938)	L.12 x L. 13

Source: (a) Company MFR Schedule C-35.
(b) Company response to OPC Production of Documents No. 3.
(c) Company MFR Schedule C-1.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

2017 Employee Incentive Compensation Adjustment

Docket No. 160021-EI
Exhibit No. HWS-3
Incentive Compensation
Page 1 of 2

Line No.	Description	Executive ($000's)	Employees ($000's)	Reference
1	Incentive Compensation 2017	37,229	60,807	a, b
2	Executive Performance Incentive			
3	Financial Portion (100%)/(40%)	(37,229)	(24,323)	Testimony
4	Customer/Shareholder Related	0	36,484	
5	Shareholder 50/50		(18,242)	Testimony
6	Rate Payer Amount		18,242	
7	Shareholder Adjustment		(42,565)	L.3 + L.5
8	O&M Factor		66.29%	b
9	O&M Expense Reduction 2017		(28,216)	L.4 x L.5
10	Jurisdictional Allocation		0.967467	a
11	Jurisdictional O&M Adjustment 2017		(27,298)	L.9 x L.101

Source: (a) Company response to OPC Interrogatory No. 139.
(b) Company response to Staff Interrogatory No. 21.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2018

2018 Employee Incentive Compensation Adjustment

Docket No. 160021-EI
Exhibit No. HWS-3
Incentive Compensation
Page 2 of 2

Line No.	Description	$000's Executive	Employees	Reference
1	Incentive Compensation 2018	37,446	60,807	a, b
2	Executive Performance Incentive			
3	Financial Portion (100%)/(40%)	(37,446)	(24,323)	Testimony
4	Customer/Shareholder Related	0	36,484	
5	Shareholder 50/50		(18,242)	Testimony
6	Rate Payer Amount		18,242	
7	Shareholder Adjustment		(42,565)	L.3 + L.5
8	O&M Factor		66.29%	b
9	O&M Expense Reduction 2018		(28,216)	L.4 x L.5
10	Jurisdictional Allocation		0.967467	a
11	Jurisdictional O&M Adjustment 2018		(27,298)	L.9 x L.101

Source: (a) Company response to OPC Interrogatory No. 139.
(b) Company response to Staff Interrogatory No. 21.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

Benefit Expense Adjustment

Docket No. 160021-EI
Exhibit No. HWS-4
Benefits Adjustment
Page 1 of 2

Line No.		000's Expense	Total	% Expensed	Reference
	2017				
1	Total Benefit Cost		164,315		a
2	Taxes/WC		(75,924)		a
3	Benefits	62,298	88,391	70.48%	b
4	Pensions	42,661	60,529		c,a
5	Post Retirement Benefits	(9,765)	(13,855)		c,a
6	Benefits Excluding Pensions and OPEB	95,194	135,065	70.48%	c
7	Employees	9,091	9,091		a
8	Cost Per Employee	10.471	14.857		L.6/L.7
9	Employee Adjustment	(256)	(256)		HWS-2;P.1
10	Employee Benefit Adjustment	(2,681)	(3,803)	70.48%	L.8 x L.9
11	Recommended Expense	92,513	131,262	70.48%	L.6 - L.10
12	Benefits Per Company	95,194	135,065	70.48%	c
13	Benefit Expense Factor Adjustment	(2,681)			L.11 - L.12
14	Jurisdictional Allocation	0.968169			b
15	Jurisdictional O&M Adjustment	(2,595)			L.13 x L.14

Source: (a) Company MFR Schedule C-35.
(b) Company MFR Schedule C-4.
(c) Estimated expense amount based expense factor on line 3.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2018

Benefit Expense Adjustment - 2018

Docket No. 160021-EI
Exhibit No. HWS-4
Benefits Adjustment
Page 2 of 2

Line No.		$000's Expense	Total	% Expensed	Reference
	2018				
1	Total Benefit Cost		168,174		a
2	Taxes/WC		(77,610)		a
3	Benefits	63,906	90,564	70.56%	b
4	Pensions	44,142	62,555		c,a
5	Post Retirement Benefits	(9,843)	(13,949)		c,a
6	Benefits Excluding Pensions and OPEB	98,205	139,170	70.56%	c
7	Employees	9,067	9,067		a
8	Cost Per Employee	10.831	15.349		L.6/L.7
9	Employee Adjustment	(232)	(232)		HWS-2;P.1
10	Employee Benefit Adjustment	(2,513)	(3,561)	70.56%	L.8 x L.9
11	Recommended Expense	95,692	135,609	70.56%	L.6 - L.10
12	Benefits Per Company	98,205	139,170	70.56%	c
13	Benefit Expense Factor Adjustment	(2,513)			L.11 - L.12
14	Jurisdictional Allocation	0.968861			b
15	Jurisdictional O&M Adjustment	(2,435)			L.13 x L.14

Source: (a) Company MFR Schedule C-35.
(b) Company MFR Schedule C-4.
(c) Estimated expense amount based expense factor on line 3.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

Payroll Tax Expense Adjustment

Docket No. 160021-EI
Exhibit No. HWS-5
Payroll Tax Adjustment
Page 1 of 2

Line No.	Description	$000's 2017 Expense	Reference
1	Federal Unemployment Tax	431	a
2	State Unemployment Tax	1,724	a
3	FICA (Social Security) Tax	67,765	a
4	Total Expense Payroll Taxes	69,920	
5	Payroll Expense	1,077,342	a
6	Effective Payroll Tax Rate	6.49%	L.4/L.5
	Base Payroll		
7	Payroll Adjustment	(17,743)	HWS-2;P.1
8	Payroll Tax Adjustment	(1,152)	L.6 x L.7
9	Jurisdictional Allocation	0.9863752	b
10	Jurisdictional O&M Adjustment	(1,136)	L.8 x L.9
	Employee Incentive Pay		
11	Effective Payroll Tax Rate	6.29%	L.3/L.5
12	Incentive Compensation Adjustment	(28,216)	Exh. HWS-3
13	Payroll Tax Adjustment	(1,775)	L.11 x L.12
14	Jurisdictional Allocation	0.9863752	b
15	Jurisdictional O&M Adjustment	(1,751)	L.13 x L.15

Source: (a) Company response to OPC Production of Document No. 3 & MFR Schedule C-35 2017.
(b) Company MFR Schedule C-1 2017.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2018

Payroll Tax Expense Adjustment - 2018

Docket No. 160021-EI
Exhibit No. HWS-5
Payroll Tax Adjustment
Page 2 of 2

Line No.	Description	$000's Expense	Reference
1	Federal Unemployment Tax	441	a
2	State Unemployment Tax	1,765	a
3	FICA (Social Security) Tax	69,389	a
4	Total Expense Payroll Taxes	71,595	
5	Payroll Expense	1,103,164	a
6	Effective Payroll Tax Rate	6.49%	L.4/L.5
	Base Payroll		
7	Payroll Adjustment	(16,530)	HWS-2;P.1
8	Payroll Tax Adjustment	(1,073)	L.6 x L.7
9	Jurisdictional Allocation	0.9863752	b
10	Jurisdictional O&M Adjustment	(1,058)	L.8 x L.9
	Employee Incentive Pay		
11	Effective Payroll Tax Rate	6.29%	L.3/L.5
12	Incentive Compensation Adjustment	(28,216)	Exh. HWS-3
13	Payroll Tax Adjustment	(1,775)	L.11 x L.12
14	Jurisdictional Allocation	0.9863752	b
15	Jurisdictional O&M Adjustment	(1,751)	L.13 x L.15

Source: (a) Company response to OPC Production of Document No. 3 & MFR Schedule C35 2018.
(b) Company MFR Schedule C-1 2018.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

Distribution Vegetative Management - Tree Trimming

Docket No. 160021-EI
Exhibit No. HWS-6
Vegetation Management

Line No.	Year	Budgeted Miles	Actual Miles	$000's Actual	$000's Budgeted/ Projected	Variance
1	2011	12,225	14,840	60,600	60,000	101.0%
2	2012	12,700	15,271	61,700	59,400	103.9%
3	2013	15,400	15,861	63,100	65,700	96.0%
4	2014	15,000	15,178	58,500	62,200	94.1%
5	2015	15,100	15,244	62,900	63,100	99.7%
6	2016				64,700	
7	2017	15,100			65,600	
8	2018	15,100			69,600	
9	Five Year Average 2011-2015			61,360		
						Variance
10	Three Year Actual to Budget 2013-2015			61,500	63,667	0.965969
12	2017 Recommended Per Citizen's (line 5 x 96.6%)				60,953	
13	2017 Requested				65,600	
14	Citizen's Recommended Adjustment 2017				(4,647)	
15	Jurisdictional Adjustment @ 100.0000% 2017				(4,647)	

Source: Dollars are from Company response to OPC Interrogatory 9.
Miles are from Company response to OPC Interrogatory 10.
Jurisdictional allocation is from Company MFR Schedule C-4 lines 9 and 22.
2016 miles are from Company response to OPC Interrogatory 259.

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2018

Distribution Vegetative Management - Tree Trimming

Docket No. 160021-EI
Exhibit No. HWS-6
Vegetation Management
Page 2 of 2

Line No.	Year	Budgeted Miles	Actual Miles	$000's Actual	$000's Budgeted/ Projected	Variance
1	2011	12,225	14,840	60,600	60,000	101.0%
2	2012	12,700	15,271	61,700	59,400	103.9%
3	2013	15,400	15,861	63,100	65,700	96.0%
4	2014	15,000	15,178	58,500	62,200	94.1%
5	2015	15,100	15,244	62,900	63,100	99.7%
6	2016				64,700	
7	2017	15,100			65,600	
8	2018	15,100			69,600	
9	Five Year Average 2011-2015			61,360		
						Variance
10	Three Year Actual to Budget 2013-2015			61,500	63,667	0.965969
12	2018 Recommended Per Citizen's (line 5 x 96.6%)				62,172	
13	2018 Requested				69,600	
14	Citizen's Recommended Adjustment 2018				(7,428)	
15	Jurisdictional Adjustment @ 100.0000% 2018				(7,428)	

Source: Dollars are from Company response to OPC Interrogatory 9.
Miles are from Company response to OPC Interrogatory 10.
Jurisdictional allocation is from Company MFR Schedule C-4 lines 9 and 22.
2016 miles are from Company response to OPC Interrogatory 259.
2018 cost is based on projected 2017 escalated 2%.

Line No.	Year	Poles Inspected	Pole Failures	$000's Actual	$000's Budgeted/ Projected	Cost Per Pole	Failure Rate
1	2007	141,332	9,801	8,578		60.69	6.93%
2	2008	143,319	10,040	12,654	14,417	88.29	7.01%
3	2009	138,970	15,243	10,896	13,024	78.41	10.97%
4	2010	141,423	15,636	10,662	15,064	75.39	11.06%
5	2011	137,315	16,585	17,517	15,300	127.57	12.08%
6	2012	139,426	16,740	14,800	15,000	106.15	12.01%
7	2013	138,310	16,715	14,200	14,900	102.67	12.09%
8	2014	146,325	17,137	3,900	12,600	26.65	11.71%
9	2015	151,679	11,384	6,000	6,300	39.56	7.51%
10	2016	145,250			6,100	42.00	
11	2017	145,250			5,800	39.93	
12	2018	145,250			5,900	40.62	
13	Actual	1,278,099	129,281	99,208			10.12%
14	5 Year Average 2011-2015			11,283	12,820		
						Variance	
15	3 Year Actual to Budget			8,033	11,267	0.713018	
16	2017 Recommended Per Citizen's				4,136		
17	2017 Requested				5,800		
18	Citizen's Recommended Adjustment 2017				(1,664)		
19	Jurisdictional Adjustment @ 99.9358% 2017				(1,663)		

Source: Lines 1-5 actual are from Company response to OPC Interrogatory 224 in Docket No. 120015-EI.
Lines 1-5 budgeted are from Company response to Staff Interrogatory 235 in Docket No. 120015-EI.
Lines 5-9 actual is from Company response to OPC Interrogatories 13 and 14 in Docket No. 160021-EI.
Lines 10-12 budgeted is from Company response to OPC Interrogatory 13 and 14 in Docket No. 160021-EI.
Jurisdictional allocation from Company MFR Schedule C-4.

Pole Inspection Expense 2018

				$000's			
Line No.	Year	Poles Inspected	Pole Failures	Actual	Budgeted/ Projected	Cost Per Pole	Failure Rate
1	2007	141,332	9,801	8,578		60.69	6.93%
2	2008	143,319	10,040	12,654	14,417	88.29	7.01%
3	2009	138,970	15,243	10,896	13,024	78.41	10.97%
4	2010	141,423	15,636	10,662	15,064	75.39	11.06%
5	2011	137,315	16,585	17,517	15,300	127.57	12.08%
6	2012	139,426	16,740	14,800	15,000	106.15	12.01%
7	2013	138,310	16,715	14,200	14,900	102.67	12.09%
8	2014	146,325	17,137	3,900	12,600	26.65	11.71%
9	2015	151,679	11,384	6,000	6,300	39.56	7.51%
10	2016	145,250			6,100	42.00	
11	2017	145,250			5,800	39.93	
12	2018	145,250			5,900	40.62	
13	Actual	1,278,099	129,281	99,208			10.12%
14	5 Year Average 2011-2015			11,283	12,820		
						Variance	
15	3 Year Actual to Budget			8,033	11,267	0.713018	
16	2018 Recommended Per Citizen's				4,207		
17	2018 Requested				5,900		
18	Citizen's Recommended Adjustment 2018				(1,693)		
19	Jurisdictional Adjustment @ 99.9422% 2018				(1,692)		

Source: Lines 1-5 actual are from Company response to OPC Interrogatory 224 in Docket No. 120015-EI.
Lines 1-5 budgeted are from Company response to Staff Interrogatory 235 in Docket No. 120015-EI.
Lines 5-9 actual is from Company response to OPC Interrogatories 13 and 14 in Docket No. 160021-EI.
Lines 10-12 budgeted is from Company response to OPC Interrogatory 13 and 14 in Docket No. 160021-EI.
Jurisdictional allocation from Company MFR Schedule C-4.

Q.
Distribution O&M Expense. Refer to FPL's response to OPC's Interrogatory No. 134. Provide a comparable summary of costs for each of the years 2006-2011. For any year during this period in which a line item increased or decreased by 15% or more, explain the reason for the change.

A.
See Attachment No. 1.

Attachment 1 - OPC Interrogatory No. 224

COST CATEGORY	Description	2006	2007	15% or More Change	Primary Reason(s) for Changes 15% or More
GROWTH	New Service Accounts	$ 23,432,543	$ 14,636,605	X	Decrease in new service accounts
	System Expansion (also provides reliability benefits)	$ 2,383,807	$ 1,817,397	X	Decrease in new service accounts
	Subtotal - Growth	$ 25,816,350	$ 16,454,002		
RELIABILITY	Vegetation Management	$ 52,627,673	$ 49,742,755		
	Feeder/Lateral Cable	$ 2,395,864	$ 1,268,831	X	
	Priority Feeders	$1,057,328	$878,960	X	Year-to-year changes in reliability program spending
	Overhead Line Inspections	$ 1,860,987	$ 2,848,698	X	result from identifying, analyzing and prioritizing
	Vault Inspections				causes of past interruptions and then targeting those
	Submarine Cable		$2,960	X	causes with the programs that will yield the largest
	VAR Management	$337,657	$548,898	X	benefits.
	Switch Cabinets	$55,587	$50,902		
	Handhole & Inspections	$ 1,292,154	$ 1,375,107		
	Small Wire Replacement	$ 1,872,012	$ 23,858	X	
	Cathodic Protection				
	Other				
	Subtotal - Reliability	$ 61,439,263	$ 56,735,306		
HARDENING	Pole Inspections (also provides reliability benefits)	$ 3,888,082	$ 8,577,975	X	1st full year implementation of FPSC approved pole inspection program
	Vegetation (6-yr. cycle laterals) (also provides reliability benefits)		-$ 15,500,000	X	1st year implementation of FPSC approved Storm Prep Initiative 1
	Hardening Plan	$ 2,302,647	$ 2,501,662		
	Underground Conversion (GAF)	$ 49,215	$ 190,888	X	1st year implementation of FPSC approved underground GAF Tariff
	Other	$ 9,692,342	$ 9,752,538		
	Subtotal - Hardening	$ 15,930,286	$ 36,573,859		
RESTORATION	Out of Service	$ 68,808,514	$ 70,612,116		
	No Loss of Service (e.g., voltage issues)	$ 10,048,442	$ 9,166,449		
	Subtotal - Restoration	$ 78,856,955	$ 79,778,565		
CUSTOMER RESPONSE					
	Relocations	$ 4,824,524	$ 4,699,285		
	Underground Cable Locate Requests	$ 5,256,764	$ 4,225,327	X	Decrease in locate requests
	Response to Customer Inquiries/Requests	$ 3,356,783	$ 2,606,671	X	Decrease in customer inquiries/requests
	Joint Use Pole Attachment Expense	$ 8,231,487	$ 8,375,827		
	Regulatory and Environmental Compliance	$ 2,715,814	$ 2,912,177		
	Subtotal - Customer Response	$ 24,385,372	$ 22,813,287		
FIELD SUPPORT	Service Center Staff Support	$ 11,568,097	$ 13,367,699		
	Staff Support	$ 11,918,263	$ 11,473,312		
	Field Support - Equipment Repair & Materials/Logistics Support	$ 4,009,313	$ 4,525,860		
	Training	$ 8,224,668	$ 10,882,722	X	Increased journeyman and apprentice training
	Safety	$ 2,096,942	$ 2,101,678		
	Meter/Transformer Installation Credits	$ (17,239,434)	$ (17,176,127)		
	Environmental Cost Recovery Expenses	$ 404,599	$ 699,854	X	FPSC reviewed/approved ECRC expenses
	Subtotal - Field Support	$ 20,987,448	$ 25,874,994		
	Subtotal - Distribution Business Unit	$ 227,416,674	$ 238,229,213		
OTHER BU'S	Other Business Units				
	Transmission - primarily Distribution substation expenses	$ 12,130,040	$ 13,432,691		
	Customer Service - primarily meter expenses	$ 17,266,588	$ 18,174,319		
	Other Business Units - (e.g., Corporate Real Estate, Human Resources)	$ 33,586,797	$ 8,687,817	X	Non-recoverable 2005 storm costs re-classified in 2006
	TOTAL DISTRIBUTION	$ 290,400,099	$ 278,523,541		

Docket No. 160021-EI
Pole Inspection
Exhibit No.___(HWS-7)
Page 5 of 9

Florida Power & Light Company
Docket No. 120015-EI
OPC's Tenth Set of Interrogatories
Interrogatory No. 224
Attachment No. 1
Page 2 of 5

Attachment 1 - OPC Interrogatory No. 224

COST CATEGORY	Description	2007	2008	15% or More Change	Primary Reason(s) for Changes 15% or More
GROWTH	New Service Accounts	$ 14,636,605	$ 10,631,146	X	Decrease in new service accounts
	System Expansion (also provides reliability benefits)	$ 1,817,397	$ 1,098,237	X	Decrease in new service accounts
	Subtotal - Growth	$ 16,454,002	$ 11,729,383		
RELIABILITY	Vegetation Management	$ 49,742,755	$ 46,384,424		
	Feeder/Lateral Cable	$ 1,263,831	$ 1,498,387	X	
	Priority Feeders	$878,860	$2,403,385	X	
	Overhead Line Inspections	$ 2,848,698	$ 1,443,495	X	
	Vault Inspections		$892,515	X	Year-to-year changes in reliability program spending
	Submarine Cable	$2,960	($1,360)	X	result from identifying, analyzing and prioritizing
	VAR Management	$548,336	$496,598		causes of past interruptions and then targeting those
	Switch Cabinets	$50,902	$25,840	X	causes with the programs that will yield the largest
	Handhole & Inspections	$ 1,375,107	$ 3,113,794	X	benefits.
	Small Wire Replacement	$ 23,858	$ 10,762	X	
	Cathodic Protection		$ 33,369	X	
	Other		$ 1,713,649	X	
	Subtotal - Reliability	$ 56,738,906	$ 58,014,897		
HARDENING	Pole Inspections (also provides reliability benefits)	$ 8,577,975	$ 12,654,048	X	Increased number of inspections/poles reinforced and replaced
	Vegetation (6-yr. cycle laterals) (also provides reliability benefits)	$ 15,500,000	$ 11,552,253	X	Decrease in lateral miles trimmed
	Hardening Plan	$ 2,591,662	$ 5,178,354	X	Increase in feeders/miles hardened
	Underground Conversion (GAF)	$ 198,888	$ 33,019	X	Reduction in GAF Tariff activity
	Other	$ 9,752,538		X	Decentralization of hardening organization
	Subtotal - Hardening	$ 36,573,059	$ 29,417,675		
RESTORATION	Out of Service	$ 70,612,116	$ 67,041,425		
	No Loss of Service (e.g., voltage issues)	$ 9,166,448	$ 10,526,383		
	Subtotal - Restoration	$ 79,778,565	$ 77,567,808		
CUSTOMER RESPONSE					
	Relocations	$ 4,693,285	$ 1,830,843	X	Reduction in relocation requests (e.g., FDOT)
	Underground Cable Locate Requests	$ 4,225,327	$ 3,507,744	X	Reduction in locate requests
	Response to Customer Inquiries/Requests	$ 2,606,671	$ 5,722,637	X	Increase in customer inquiries/requests
	Joint Use Pole Attachment Expense	$ 8,375,827	$ 8,357,864		
	Regulatory and Environmental Compliance	$ 2,912,177	$ 4,137,350	X	Increase in non-ECRC standards/compliance
	Subtotal - Customer Response	$ 22,813,287	$ 23,556,438		
FIELD SUPPORT	Service Center Staff Support	$ 13,367,699	$ 14,280,136		
	Staff Support	$ 11,473,312	$ 10,141,413		
	Field Support - Equipment Repair & Materials/Logistics Support	$ 4,525,860	$ 3,816,739		
	Training	$ 10,882,722	$ 7,089,190	X	Reduction in Journeymen & Apprentice Training
	Safety	$ 2,101,673	$ 2,870,425	X	Increased safety training
	Meter/Transformer Installation Credits	$ (17,176,127)	$ (13,261,520)	X	Reduced meter/transformer install credits associated with decrease in new service accounts
	Environmental Cost Recovery Expenses	$ 699,854	$ 897	X	FPSC reviewed/approved ECRC expenses
	Subtotal - Field Support	$ 25,874,994	$ 24,937,280		
	Subtotal - Distribution Business Unit	$ 238,229,213	$ 225,223,440		
OTHER BU'S	Other Business Units				
	Transmission - primarily Distribution substation expenses	$ 13,432,091	$ 14,570,679		
	Customer Service - primarily meter expenses	$ 18,174,319	$ 18,166,811		
	Other Business Units - (e.g., Corporate Real Estate, Human Resources)	$ 8,687,917	$ 14,191,435	X	2008 severance/realignment costs
	TOTAL DISTRIBUTION	$ 278,523,541	$ 272,152,365		

Attachment 1 - OPC Interrogatory No. 224

COST CATEGORY	Description	2008	2009	15% or More Change	Primary Reason(s) for Changes 15% or More
GROWTH	New Service Accounts	$ 10,631,146	$ 8,353,924	X	Decrease in new service accounts
	System Expansion (also provides reliability benefits)	$ 1,098,237	$ 412,676	X	Decrease in new service accounts
	Subtotal - Growth	$ 11,729,383	$ 8,766,601		
RELIABILITY	Vegetation Management	$ 46,384,424	$ 37,782,929	X	Reduced rates/charges from new contract with FPL's primary tree trimming vendor
	Feeder/Lateral Cable	$ 1,498,387	$ 1,088,246	X	
	Priority Feeders	$2,403,385	$1,360,064	X	
	Overhead Line Inspections	$ 1,443,495	$ 732,436	X	
	Vault Inspections	$892,515	$665,286	X	Year-to-year changes in reliability program spending result from identifying, analyzing and prioritizing causes of past interruptions and then targeting those causes with the programs that will yield the largest benefits.
	Submarine Cable	($1,360)	$2,327	X	
	VAR Management	$496,598	$389,188	X	
	Switch Cabinets	$25,840	$10,223	X	
	Handhole & Inspections	$ 3,113,794	$ 2,905,849		
	Small Wire Replacement	$ 10,762	$ 219	X	
	Cathodic Protection	$ 33,369		X	
	Other	$ 1,713,649	$ 1,005,298	X	
	Subtotal - Reliability	$ 58,014,857	$ 45,942,064		
HARDENING	Pole Inspections (also provides reliability benefits)	$ 12,654,048	$ 10,896,010		
	Vegetation (6-yr. cycle laterals) (also provides reliability benefits)	$ 11,552,253	$ 14,867,433	X	Increase in miles trimmed
	Hardening Plan	$ 5,178,354	$ 6,560,994	X	Increase in feeders/miles hardened
	Underground Conversion (GAF)	$ 33,019	$ (51,448)	X	Decrease in GAF Tariff activity
	Other				
	Subtotal - Hardening	$ 29,417,675	$ 32,272,930		
RESTORATION	Out of Service	$ 67,041,425	$ 65,917,860		
	No Loss of Service (e.g., voltage issues)	$ 10,526,383	$ 10,720,172		
	Subtotal - Restoration	$ 77,567,808	$ 76,638,032		
CUSTOMER RESPONSE					
	Relocations	$ 1,830,843	$ 1,971,419		
	Underground Cable Locate Requests	$ 3,507,744	$ 3,199,107		
	Response to Customer Inquiries/Requests	$ 5,722,687	$ 5,180,954		
	Joint Use Pole Attachment Expense	$ 8,357,864	$ 8,439,364		
	Regulatory and Environmental Compliance	$ 4,137,350	$ 6,075,461	X	Increase in non-ECRC standards/compliance
	Subtotal - Customer Response	$ 23,556,438	$ 24,866,304		
FIELD SUPPORT	Service Center Staff Support	$ 14,280,136	$ 14,630,157		
	Staff Support	$ 10,141,413	$ 2,601,680	X	Business realignment implementation results
	Field Support - Equipment Repair & Materials/Logistics Support	$ 3,816,739	$ 3,132,074	X	Reduction in transformer repairs
	Training	$ 7,089,190	$ 3,540,446	X	Reduction in journeymen and apprentice training
	Safety	$ 2,870,425	$ 3,327,091	X	Increase in safety training
	Meter/Transformer Installation Credits	$ (13,261,520)	$ (11,503,277)		
	Environmental Cost Recovery Expenses	$ 897	$ 0	X	FPSC reviewed/approved ECRC expenses
	Subtotal - Field Support	$ 24,937,280	$ 15,728,171		
	Subtotal - Distribution Business Unit	$ 225,223,440	$ 204,214,101		
OTHER BU'S	Other Business Units				
	Transmission - primarily Distribution substation expenses	$ 14,570,679	$ 18,701,010		
	Customer Service - primarily meter expenses	$ 18,166,811	$ 16,999,402		
	Other Business Units - (e.g., Corporate Real Estate, Human Resources)	$ 14,191,435	$ 6,920,066	X	2008 severence/realignment costs; business realignment implementation results
	TOTAL DISTRIBUTION	$ 272,152,365	$ 244,834,579		

Attachment 1 - OPC Interrogatory No. 224

COST CATEGORY	Description	2009	2010	15% or More Change	
GROWTH	New Service Accounts	$ 8,353,924	$ 6,911,272	X	Decrease in new service accounts
	System Expansion (also provides reliability benefits)	$ 412,676	$ 235,976	X	Decrease in new service accounts
	Subtotal - Growth	$ 8,766,601	$ 7,147,248		
RELIABILITY	Vegetation Management	$ 37,782,929	$ 45,321,568	X	Increase in feeder/mid-cycle trimming
	Feeder/Lateral Cable	$ 1,088,246	$ 2,210,231	X	
	Priority Feeders	$1,380,064	$1,229,333		
	Overhead Line Inspections	$ 732,436	$ 1,624,333	X	Year-to-year changes in reliability program spending
	Vault Inspections	$665,286	$1,280,230	X	result from identifying, analyzing and prioritizing
	Submarine Cable	$2,327	$4,999	X	causes of past interruptions and then targeting those
	VAR Management	$389,188	$215,008	X	causes with the programs that will yield the largest
	Switch Cabinets	$10,223	$16,828	X	benefits.
	Handhole & Inspections	$ 2,905,849	$ 2,900,877		
	Small Wire Replacement	$ 219	$ 527	X	
	Cathodic Protection		$ 167,778	X	
	Other	$ 1,005,298	$ 1,059,604		
	Subtotal - Reliability	$ 45,942,064	$ 56,030,516		
HARDENING	Pole Inspections (also provides reliability benefits)	$ 10,896,010	$ 10,662,172		
	Vegetation (6-yr. cycle laterals) (also provides reliability benefits)	$ 14,867,433	$ 12,278,689	X	Reduction in lateral miles trimmed
	Hardening Plan	$ 6,560,934	$ 2,888,114	X	Reduction in feeders/miles hardened
	Underground Conversion (GAF)	$ (51,448)	$ (1,645)	X	Reduced GAF Tariff activity
	Other				
	Subtotal - Hardening	$ 32,272,930	$ 25,827,330		
RESTORATION	Out of Service	$ 65,917,860	$ 76,017,783	X	Increase in restoration activity
	No Loss of Service (e.g., voltage issues)	$ 10,720,172	$ 11,648,609		
	Subtotal - Restoration	$ 76,638,032	$ 87,666,391		
CUSTOMER RESPONSE					
	Relocations	$ 1,971,419	$ 1,291,565	X	Decrease in relocation requests (e.g., FDOT)
	Underground Cable Locate Requests	$ 3,199,107	$ 3,265,003		
	Response to Customer Inquiries/Requests	$ 5,180,854	$ 5,129,351		
	Joint Use Pole Attachment Expense	$ 8,439,364	$ 8,524,352		
	Regulatory and Environmental Compliance	$ 6,075,461	$ 6,936,199		
	Subtotal - Customer Response	$ 24,866,304	$ 25,146,469		
FIELD SUPPORT	Service Center Staff Support	$ 14,630,157	$ 14,723,153		
	Staff Support	$ 2,601,680	$ 3,361,010	X	Increased information system support activities
	Field Support - Equipment Repair & Materials/Logistics Support	$ 3,132,074	$ 3,523,416		
	Training	$ 3,540,446	$ 1,963,508	X	Reduction in apprentice training
	Safety	$ 3,327,091	$ 5,726,529	X	Increased safety training; implementaion of new pole climbing harness
	Meter/Transformer Installation Credits	$ (11,503,277)	$ (10,283,865)		
	Environmental Cost Recovery Expenses	$ 0	$ 152,029	X	FPSC reviewed/approved ECRC expenses
	Subtotal - Field Support	$ 15,728,171	$ 18,165,779		
	Subtotal - Distribution Business Unit	$ 204,214,101	$ 220,983,734		
OTHER BU'S	Other Business Units				
	Transmission - primarily Distribution substation expenses	$ 16,701,010	$ 18,895,686		
	Customer Service - primarily meter expenses	$ 16,999,402	$ 18,057,724		
	Other Business Units - (e.g., Corporate Real Estate, Human Resources)	$ 6,920,065	$ 7,141,004		
	TOTAL DISTRIBUTION	$ 244,834,579	$ 265,078,148		

Attachment 1 - OPC Interrogatory No. 224

COST CATEGORY	Description	2010	2011	15% or More Change	
GROWTH	New Service Accounts	$ 6,911,272	$ 7,728,417		
	System Expansion (also provides reliability benefits)	$ 235,976	$ 300,821	X	
	Subtotal - Growth	$ 7,147,248	$ 8,029,238		
RELIABILITY	Vegetation Management	$ 45,321,568	$ 44,768,661		
	Feeder/Lateral Cable	$ 2,210,231	$ 1,380,286	X	
	Priority Feeders	$1,229,233	$ 2,376,851	X	
	Overhead Line Inspections	$ 1,634,333	$ 2,585,471	X	Year-to-year changes in reliability program spending result from identifying, analyzing and prioritizing causes of past interruptions and then targeting those causes with the programs that will yield the largest benefits.
	Vault Inspections	$1,280,230	$ 1,561,404	X	
	Submarine Cable	$4,999	$ 5,313		
	VAR Management	$215,008	$ 919,723	X	
	Switch Cabinets	$16,828	$ 29,241	X	
	Handhole & Inspections	$ 2,900,077	$ 3,165,152		
	Small Wire Replacement	$ 527	$ 260,297	X	
	Cathodic Protection	$ 167,778	$ 66,738	X	
	Other	$ 1,059,604	$ 2,137,402	X	
	Subtotal - Reliability	$ 56,030,516	$ 59,256,531		
HARDENING	Pole Inspections (also provides reliability benefits)	$ 10,662,172	$ 17,517,318	X	Increase in poles reinforced/transferred
	Vegetation (6-yr. cycle laterals) (also provides reliability benefits)	$ 12,278,689	$ 15,613,352	X	Increase in miles trimmed
	Hardening Plan	$ 2,888,114	$ 2,043,401	X	Decrease in feeders hardened
	Underground Conversion (GAF)	$ (1,645)	$ 143,325	X	Increase in GAF Tariff activity
	Other				
	Subtotal - Hardening	$ 25,827,330	$ 35,317,396		
RESTORATION	Out of Service	$ 76,017,783	$ 82,477,595	X	re-classification of costs from no loss of service to out of service
	No Loss of Service (e.g., voltage issues)	$ 11,648,609	$ 5,614,592	X	re-classification of costs from no loss of service to out of service
	Subtotal - Restoration	$ 87,666,391	$ 88,092,187		
CUSTOMER RESPONSE					
	Relocations	$ 1,291,565	$ 634,644	X	Decrease in relocation requests (e.g., FDOT)
	Underground Cable Locate Requests	$ 3,265,008	$ 2,907,215		
	Response to Customer Inquiries/Requests	$ 5,129,351	$ 6,285,402	X	Increase in customer inquiries/requests
	Joint Use Pole Attachment Expense	$ 8,524,352	$ 8,033,083		
	Regulatory and Environmental Compliance	$ 6,936,199	$ 7,699,014		
	Subtotal - Customer Response	$ 25,146,469	$ 25,559,357		
FIELD SUPPORT	Service Center Staff Support	$ 14,723,153	$ 14,512,089		
	Staff Support	$ 3,361,010	$ 4,720,495	X	Re-alignment of costs - field/staff support
	Field Support - Equipment Repair & Materials/Logistics Support	$ 3,523,416	$ 2,840,484	X	Re-alignment of costs - field/staff support
	Training	$ 1,963,508	$ 1,974,747		
	Safety	$ 5,726,529	$ 5,246,796		
	Meter/Transformer Installation Credits	$ (10,283,865)	$ (10,024,259)		
	Environmental Cost Recovery Expenses	$ 152,029	$ 3,680	X	FPSC reviewed/approved ECRC expenses
	Subtotal - Field Support	$ 19,165,779	$ 19,274,031		
	Subtotal - Distribution Business Unit	$ 220,983,734	$ 235,528,740		
OTHER BU'S	Other Business Units				
	Transmission - primarily Distribution substation expenses	$ 18,895,686	$ 21,710,284		
	Customer Service - primarily meter expenses	$ 18,057,724	$ 20,466,502		
	Other Business Units - (e.g., Corporate Real Estate, Human Resources)	$ 7,141,004	$ 6,341,008		
	TOTAL DISTRIBUTION	$ 265,078,148	$ 284,046,535		

Florida Power & Light Company
Docket No. 120015-EI
Staff's Sixth Set of Interrogatories
Interrogatory No. 235
Page 1 of 1

Q.
Please provide a listing describing specific FPL actions taken between 2008 and year-end 2010, if any, specifically directed at achieving the trends shown in Figures 3-1 through 3-8. Include in your response the annual budgeted and actual program expense levels.

A.
All of FPL's reliability initiatives are implemented to achieve improved reliability performance, irrespective of a reliability or complaint metric's trend (positive or negative). Below is the list of the reliability initiatives provided and described in Exhibit GKH-2, along with associated budget/actual expenses for 2008-2010. Each of the programs listed below would have an impact on the final results/trends shown in Figures 3-1 through 3-8.

	2008 $		2009 $		2010 $	
Program	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Hardening Plan *	5,178,354	6,248,950	6,560,934	6,892,427	2,888,114	3,660,858
Pole Inspections *	12,654,048	14,417,530	10,896,010	13,023,779	10,662,172	15,063,872
Vegetation Management *	57,936,677	63,400,000	52,650,362	68,300,000	57,600,257	61,489,010
Feeder/Lateral Cable	1,498,387	1,552,200	1,088,246	1,407,291	2,210,231	1,762,391
Priority Feeders	2,403,385	1,543,556	1,360,064	944,027	1,229,333	2,176,652
Overhead Line Inspections	1,443,495	2,652,326	732,436	1,073,546	1,624,333	3,379,593
Vault Inspections	892,515	1,273,754	665,460	1,119,777	1,280,230	1,908,992
Submarine Cable			2,327	111,205	4,999	
VAR Management	496,598	1,139,486	389,188	1,462,239	215,008	350,105
Switch Cabinets	25,840	63,084	10,223	98,099	16,828	
Handhole Inspections	3,050,431	1,262,591	2,905,849	4,373,580	2,900,077	2,818,997
Small Wire Replacement	9,515		219		527	
Cathodic Protection	33,369	227,400		201,044	167,778	57,100
System Expansion	1,098,237	2,389,395	412,676	1,749,711	235,976	188,735

*** Hardening/Storm Preparedness programs which also provide day-to-day reliability benefits**

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

Directors and Officers Liability Insurance Adjustment

Line No.	Description	$000's Expense	Reference
1	DOL Insurance 2017 and 2018	2,781	a
2	Adjustment to Shareholders	(1,391)	Testimony
3	Jurisdictional Allocation 2017 and 2018	0.984797	
4	Jurisdictional O&M Adjustment 2017 and 2018	(1,369)	

Source: (a) Company response to OPC Interrogatory No. 60 in Docket No. 120015-EI.

Q.

Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for calendar year 2009, 2010, 2011 and 2012 to date. Indicate the accounts and amounts in which each item of insurance is recorded.

A.

See Attachment No. 1 for requested information for 2009 through 2011, and the 2013 Test Year. Consistent with FPL's obligations to the U.S. Securities and Exchange Commission, the information requested for 2012 actuals (i.e. for the first quarter of 2012) will be provided in a supplemental response once it has been publicly released, which is expected to be on or after April 27, 2012. In addition, for amounts associated with medical and dental insurance, please see MFR C-35.

Acct 924 - Property Insurance

Expense Description	2009	2010	2011	2013 Test year
Property Insurance				
Prop Insurance-Other	8,541,272.69	7,619,832.83	8,499,870.39	10,629,598.00
Prop Insurance-PSL/PTN	8,416,680.73	7,924,585.00	7,619,703.64	9,603,209.00
Property Ins Nuclear Outage-PSL/PTN	2,172,616.93	2,173,261.82	2,126,557.57	2,288,623.00
FMPA and Participation Agreement Reimb	1,084,173.79	(304,096.51)	(69,418.90)	-
Nucl Outage distribution refund-PSL/PTN	(4,629,325.04)	-	(3,237,258.00)	-
Nuclear Property Distribution Refund-PSL/PTN	(6,642,546.30)	-	(4,614,418.00)	-
Property insurance - Storm	321,678.10	806,236.38	571,221.16	-
Prop insurance-Aircraft	210,720.26	17,372.17	-	-
Prop insurance-Crime	208,436.62	188,513.57	178,153.19	183,179.00
Orot Flagler	-	-	258,149.13	-
Other miscellaneous (items less than $100K)	48,294.20	10,977.66	56,908.14	-
Total	7,732,001.98	18,436,682.82	11,389,468.32	22,704,609.00

Acct 925 - Liability Insurance Premiums

Expense Description	2009	2010	2011	2013 Test year
Liability Insurance				
Liability Insurance-Excess	5,135,231.00	5,291,503.00	5,645,822.00	7,162,464.00
Liability Insurance-D&O	3,033,245.00	2,815,602.03	2,623,203.22	2,781,173.00
Liability Insurance-PSL/PTN	1,887,241.08	2,540,279.71	2,689,355.77	2,581,878.00
Liability Insurance-Fiduciary	318,728.54	308,301.66	275,642.47	282,103.00
Worker's Comp				
Premium	7,839,304.17	7,899,270.52	7,394,907.14	7,540,123.00
Admin Costs	1,860,142.13	1,787,604.22	869,452.16	-
Bankrupt Carriers Adj	(484,493.56)	157,003.39	(428,614.81)	-
Payroll OH Loading	(1,948,216.82)	(1,470,093.51)	(896,968.45)	-
Employee Self Ins Reserve Adj	(405,960.85)	(485,134.00)	(330,635.43)	-
Affiliate Management Fee	(235,505.85)	(219,847.45)	(160,485.12)	-
Other miscellaneous (items less than $100K)	(165,296.61)	(186,758.12)	(69,998.20)	(34,742.00)
Total	16,814,418.23	18,437,631.45	17,611,680.75	20,312,999.00

Acct 926

Expense Description	2009	2010	2011	2013 Test year
Life Insurance & Long Term Disability	1,397,796.51	1,447,419.53	4,940,728.83	5,245,000.00
Total	1,397,796.51	1,447,419.53	4,940,728.83	5,245,000.00
Grand Total	25,944,218.72	38,321,733.90	33,941,877.90	48,262,608.00

Q.
Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for calendar year 2009, 2010, 2011 and 2012 to date. Indicate the accounts and amounts in which each item of insurance is recorded.

A.
As indicated in FPL's response filed on April 23, 2012, FPL stated it would file a supplemental response once it has publicly released information for 2012 actuals, which would be no later than April 27, 2012. See Attachment No. 1 for the requested information for year-to-date March 2012, except for medical and dental insurance. The year-to-date amounts for medical and dental insurance as of March 2012 are $20,423,121 and $1,309,546, respectively.

FERC Acct 924 - Property Insurance

Expense Description	YTD March 2012
Property Insurance	
Prop Insurance-Other	2,207,311.12
Prop insurance-PSL/PTN	1,894,084.56
Property Ins Nuclear ~~Outage~~-PSL/PTN	536,864.64
Property insurance - Storm	137,361.20
Prop insurance-Crime	43,948.11
Orot Flagler	80,707.74
Total	4,900,277.37

FERC Acct 925 - Liability Insurance Premiums

Expense Description	YTD March 2012
Liability Insurance	
Liability insurance-Excess	1,415,333.31
Liability insurance-D&O	627,909.61
Liability insurance-PSL/PTN	915,442.95
Liability insurance-Fiduciary	66,514.25
Worker's Comp	
Premium	1,785,064.80
Admin Costs	87,251.39
OUC & FMPA Reimbursement	(239,032.68)
Bankrupt Carriers Adj	25,077.61
Payroll OH Loading	91,088.48
Other miscellaneous (items less than $25K)	2,173.51
Total	4,776,823.23

FERC Acct 926

Expense Description	YTD March 2012
Life Insurance & Long Term Disability	1,326,113.53
Total	1,326,113.53
Grand Total	11,003,214.13

FLORIDA POWER & LIGHT COMPANY
Projected Test Year Ended December 31, 2017

Storm Hardening Capital

Docket No. 160021-EI
Exhibit No. HWS-9
Storm Hardening

Line No.	Description	2012	2013	2014	2015	2016	2017	2018
					$000's			
1	Feeders	50,500	105,600	155,300	201,000	357,200	487,200	675,300
2	Laterals	0	0	0	0	0	0	75,800
3	Storm Surge	0	1,000	2,400	2,600	0	0	0
4	Replacements	24,400	27,700	41,400	49,000	45,100	50,200	50,300
5	Insulators	1,200	4,900	2,900	700	0	0	0
	Inspections							
6	Distribution	67,500	69,700	70,100	73,000	45,700	47,500	49,800
7	Transmission	27,500	31,000	31,200	36,200	32,000	32,500	33,800
	Over/Under							
8	Conversions	4,400	2,700	2,600	1,700	7,500	7,700	8,000
9	Subtotal	175,500	242,600	305,900	364,200	487,500	625,100	893,000
10	Expensed	(35,500)	(29,600)	(5,900)	(16,200)	(16,500)	(21,100)	(25,000)
11	Capital	140,000	213,000	300,000	348,000	471,000	604,000	868,000
12	Budgeted	130,000	142,000	273,000	297,000	471,000	604,000	868,000
13	Change		152.14%	140.85%	116.00%	135.34%	128.24%	143.71%
14	2016 YTD Annualized					446,400		
15	2016 Variance					94.78%		
16	Citizens Recommended Plant Adjustment 2017 and 2018						(31,546)	(45,335)
17	Depreciation Adjustment @ 2.7147% 2017 and 2018						(856)	(1,231)
18	Accumulated Depreciation Adjustment 2017 and 2018						(428)	(615)

Source: Lines 1-8 are from response to SFHHA Interrogatory (IR) No. 99.
Line 11 is from response to OPC IR No. 276.
Line 12 is from response to OPC IR Nos. 111, 362,and 366.
Line 14 is based on response to OPC IR No. 363 which shows actual May YTD spending of $186 million.