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October 16, 2013

Ann Cole
Commission Clerk and
Administrative Services
Room 100, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket Nos. 130140-EI, 130151-EI, & 130092-EI

Dear Ms. Cole:

Today the Office of Public Counsel's Testimony and Exhibits of Mark E. Garrett are being submitted via the Florida Public Service Commission's web based electronic filing system.

Yours truly,

Joe A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

JAM:bsr

cc: All parties of record
Suzanne Brownless
Martha Barrera
Martha Brown
Charles Murphy
Caroline Klancke

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Gulf Power Company	DOCKET NO.: 130140-EI
In re: 2013 depreciation and dismantlement study by Gulf Power Company	DOCKET NO.: 130151-EI
In re: Petition of Gulf Power Company to include the Plant Daniel Bromine and ACI Project, the Plant Crist Transmission Upgrades Project, and the Plant Smith Transmission Upgrades Project in the Company's program, and approve the costs associated with these compliance strategies for recovery through the ECRC.	DOCKET NO.: 130092-EI FILED: October 16, 2013

DIRECT TESTIMONY

OF

MARK E. GARRETT

ON BEHALF OF THE CITIZENS OF FLORIDA

TABLE OF CONTENTS

EXHIBITS OF MARK E. GARRETT

DIRECT TESTIMONY

OF

MARK E. GARRETT

On Behalf Of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket Nos. 130140-EI, 130151-EI and 130092-EI

<u>SECTION I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY</u>

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Mark Garrett. I am the President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation, and consulting services.

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION?

A. I am a licensed attorney and a certified public accountant. I work as a consultant in the area of public utility regulation. I received my bachelor's degree from the University of Oklahoma and completed post-graduate hours at Stephen F. Austin State University and at the University of Texas at Arlington and Pan American. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized ($300 million) corporation in Dallas, I managed the Company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission ("OCC") from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma. Since leaving the OCC, I have worked on various rate cases and other regulatory proceedings on behalf of various customers and customer groups.

Q. HAVE YOUR QUALIFICATIONS BEEN ACCEPTED IN PROCEEDINGS DEALING WITH COST-OF-SERVICE AND OTHER RATEMAKING ISSUES?

A. Yes, they have. A more complete description of my qualifications and a list of the proceedings in which I have been involved are included at **Exhibit MEG-1** attached to this testimony.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A. I am appearing on behalf of the Florida Office of Public Counsel ("OPC") which represents the interests of consumers in utility rate proceedings before the Florida Public Service Commission ("FPSC" of "Commission"). Accordingly, I am appearing on behalf of the Citizens of the State of Florida ("Citizens").

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

A. Garrett Group, LLC, was retained by OPC to review the rate request of Gulf Power Company ("Gulf" or "Company"). I am presenting OPC's overall recommended revenue requirement in this case. I also sponsor several adjustments to the Company's proposed rate base and operating income.

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

A. Yes. Scott Norwood of Norwood Energy Consulting, LLC; Jacob Pous of Diversified Utility Consultants, Inc.; and Dr. J. Randall Woolridge are also presenting testimony.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I first summarize the revenue requirement recommended by Citizens in this case. The financial summary includes the recommendations of each of the Citizens' witnesses in this case. I then address various adjustments I am sponsoring in this proceeding.

SECTION II. SUMMARY OF OPC'S RECOMMENDATIONS AND ADJUSTMENTS

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

A. Yes. I have prepared Exhibit MEG-3, consisting of Schedules A, A-1, B-1 through B-4, C-1 through C-15, and D-1. The schedules presented in Exhibit MEG-3 are also consecutively numbered in the schedule headers.

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

A. Schedule A presents the revenue requirement calculation, at this time, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the recommendations made by Citizens' witnesses Norwood, Pous, and Woolridge. The calculation of the net operating income multiplier (or gross revenue conversion factor) is presented on Schedule A-1. The OPC-adjusted rate base is presented at Schedule B-1. The OPC adjustments to rate base are summarized on Schedule B-2. The supporting calculations for the rate base adjustments are presented on Schedules B-3 and B-4. The OPC net operating income statement is presented at Schedule C-1. The OPC adjustments to net operating income are summarized on Schedule C-2. The supporting calculations for the net operating adjustments are presented on Schedules C-3 through C-15.

Q. WOULD YOU PLEASE BRIEFLY DISCUSS SCHEDULE D-1?

A. Schedule D-1 presents OPC's recommended capital structure and overall rate of return based on the recommendations of OPC witness Dr. Woolridge. Schedule D-1 applies Dr. Woolridge's recommended cost rates to the recommended capital ratios, resulting in an adjusted overall recommended rate of return of 5.52%.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR GULF POWER COMPANY?

A. As shown on Schedule A, OPC's recommended adjustments in this case result in a revenue decrease for Gulf Power Company of $2.005 million. This is $76.398 million less than the $74.393 million increase in base rates requested by Gulf in its filing.

Q. WHAT IS THE OPC'S RECOMMENDATION IN REGARDS TO THE REQUESTED $16.392 MILLION STEP INCREASE TO BECOME EFFECTIVE JULY 1, 2015?

A. OPC witness Norwood testifies to this issue and recommends that the Commission deny Gulf's request for a step increase.

Q. PLEASE PROVIDE A SUMMARY OF OPC'S ADJUSTMENTS.

A. The table below reflects the revenue requirement impacts of the OPC adjustments.

Table 1: Summary of OPC's Adjustments				
Ln	Adjustment Description	OPC Witness	Total Co. Adjustment ($000)	Florida Retail Rate Impact ($000)
1	Short-Term Incentive – Financial-Based	Garrett	$7,536	$7,390
2	Short-Term Incentive – Customer Service	Garrett	$1,043	$1,023
3	Short-Term Incentive – Payroll Tax	Garrett	$656	$643
4	Long-Term Incentive – Financial-Based	Garrett	$3,160	$3,095
5	Supplemental Executive Retirement Pay	Garrett	$2,220	$2,174
6	Payroll Expense Adjustment	Garrett	$2,248	$2,205
7	Payroll Tax Expense Adjustment	Garrett	$172	$169
8	Employee Medical Expense Adjustment	Garrett	$387	$380
9	Directors and Officers Liability Insurance	Garrett	$48	$47
10	Storm Damage Accrual Adjustment	Garrett	$9,000	$8,861
11	Corporate Aircraft Cost Allocation	Garrett	$2,244	$2,198
12	Uncollectible Accounts Adjustment	Garrett	$146	$144
13	Annualized Revenue Adjustment	Garrett	$1,244	$1,244
14	Transmission Expense Adjustment	Norwood	$637	$618
15	Depreciation Expense Adjustment	Pous	$14,133	$13,878
16	Rate Base – Capitalized Incentives	Garrett	$2,420	$223
17	Rate Base – Storm Damage Reserve	Garrett	$35,372	$3,273
18	Cost of Capital (9.0% ROE)	Woolridge		$28,615
19	Revenue Taxes, Assessment and Rounding	Garrett		$218
20	Total Florida Rate Impact			$76,398

Q. DOES YOUR TESTIMONY PROVIDE A COMPREHENSIVE ANALYSIS OF THE COMPANY'S PRO FORMA REVENUE REQUIREMENT?

A. No. My testimony addresses only a limited number of material issues in this case. My recommendations should be read in conjunction with the revenue requirement recommendations of the other parties. This testimony should not be misconstrued to mean that OPC supports a decrease in Gulf's jurisdictional pro forma rates of *only* $76.398 million. This testimony instead stands for the proposition that OPC supports a decrease of $76.398 million as to the issues identified.

SECTION III. EMPLOYEE COMPENSATION EXPENSE ADJUSTMENTS

A. Short-Term Incentives

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO INCLUDE SHORT-TERM INCENTIVE COMPENSATION EXPENSE IN RATES?

A. Yes. The Company seeks to include $14,567,000 in test year O&M expenses for short-term incentive compensation expense. The Company includes 100% of the annual incentive plan compensation for both Gulf and its allocated share of Southern Company Services, Inc. ("SCS"). As shown in the Company's response to Citizens' Interrogatory No. 80, there is no adjustment to remove any of its test year incentive expense from cost of service, even though Gulf admits that most of the annual incentive plan is tied to financial performance measures.

The Company's proposed inclusion of financial-based incentive compensation is addressed in the direct testimony of Gulf witness James M. Garvie. Mr. Garvie, on page 7, asserts that the incentives are part of a total package of compensation and benefits that are reasonable when compared with other companies. Mr. Garvie also asserts on pages 11-13, that incentive programs tied to cost controls and return on equity help companies attract, motivate and retain talented employees, and that, without financial-based incentives, employees would not be motivated to promote the financial health of the Company. Gulf's test year incentive expense levels and the amounts included in cost of service are set forth in the table below:

Table 2: Short-Term Incentive Compensation Expense in Cost of Service				
Description	Gulf Direct	Allocated to Gulf	Hiring Lag	Total Test Year Expense
Expense	$10,206,000	$4,361,000	($74,000)	$14,493,000
Capital	3,261,000	828,000		4,089,000
Other	1,074,000	214,000		1,288,000
Total Short-Term Incentives	**$14,541,000**	**$5,403,000**	**($74,000)**	**$19,870,000**
Source: Gulf's Responses to Citizens' Interrogatory No. 80				

Q. **WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S INCENTIVE COMPENSATION EXPENSE?**

A. The general rule followed in most states is that incentive payments related to the financial performance of the company primarily benefit shareholders and thus are excluded for ratemaking purposes. Under this rule, some short-term incentive expense and virtually all long-term incentive expense is excluded. In my opinion, this rule should be applied to Gulf's incentive plans.

Q. **HOW MUCH OF THE COMPANY'S SHORT-TERM INCENTIVE COMPENSATION IS DIRECTLY TIED TO FINANCIAL PERFORMANCE?**

A. According to the Company's Response to Citizens' Interrogatory No. 80, parts (h) and (i), 17% of the Company's short-term test year plan expense is tied to Gulf's return on equity and 35% is tied to Southern Company's earnings per share goal. Thus, 52%, or $7,536,360 of Gulf's short-term incentive plan costs, is tied to financial goals.

Q. HOW ARE SHORT-TERM INCENTIVE COSTS GENERALLY TREATED IN FLORIDA?

A. It appears that Florida generally excludes incentives tied to financial performance. For example, in Florida Power and Light Company ("FPL") Order No. PSC-10-0153-FOF-EI, at pp. 95-150, the Commission excluded 50% of the annual incentive plan costs because this was the amount tied to financial measures. Similarly, in a recent Progress Energy rate case (now Duke Energy), the Commission disallowed 100% of the Company's incentive plan costs because they were tied too closely to financial performance. In Order No. PSC-10-0131-FOF-EI, page 915, the Commission stated:

> We believe that incentive compensation provides no benefit to the ratepayers and constitutes nothing more than added compensation to employees. Especially in light of today's economic climate, we believe that PEF should pay the entire cost of incentive compensation, as its customers do not receive a significant benefit from it. Accordingly, we find that the 2010 allowance for incentive compensation shall be reduced by $32,854,378 jurisdictional ($37,465,650 system).

Q. HOW WERE THESE COSTS TREATED BY THE COMMISSION IN GULF'S LAST RATE CASE?

A. In Gulf's last rate case, the Commission included the costs of the Company's short-term Performance Pay Plan in rates, finding that Gulf's ratepayers may benefit if a healthy financial position allows the Company to raise funds at a lower cost than it otherwise could.

Q. DO YOU BELIEVE THAT GULF'S RATEPAYERS MIGHT BENEFIT FROM A FINANCIALLY HEALTHY UTILITY COMPANY?

A. In theory, ratepayers can receive some benefit from having a financially healthy utility. In fact, some states even acknowledge that ratepayers receive some benefit from financial-based incentives; however, those states still exclude them from rates. The overwhelming consensus is that financial-based incentives clearly benefit shareholders more than they do ratepayers. As examples, financial-based incentives can motivate management to argue for higher-than-necessary ROEs in rate cases, or to include financial-based short-term and stock-based long-term incentives in rates.

Each of these items will increase earnings with little or no corresponding benefit to ratepayers. Also, incentives to increase earnings can potentially pose more of a risk to ratepayers than a benefit. For example, incentives that motivate management to increase earnings can also motivate management to temporarily cut costs between rate cases by foregoing or postponing maintenance projects. Decisions of this type may benefit shareholders in the short run, yet they put ratepayers at risk in the long run. The bottom line is that incentives paid to increase earnings should be paid out of the higher earnings they help achieve.

Q. WHAT IS THE UNDERLYING POLICY OR RATIONALE FOR EXCLUDING INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE?

A. When incentive compensation costs associated with financial performance are excluded from rates, the rationale is generally based on one or more of the following reasons:

(1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned upon meeting some predetermined financial goal such as achieving a certain increase in earnings, reaching a targeted stock price or meeting budget

objectives. If the predetermined goals are not met, the incentive payment is not made, or payment is made at some lesser amount. Therefore, there is no certainty from year to year as to what the level of the payment may be or whether the payment will be made at all. It is generally considered inappropriate to set rates to recover a tentative level of expense.

(2) **Many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers.** For example, an unusually hot summer can easily trigger an incentive payment based on company earnings for an electric utility. Obviously, weather conditions are outside the control of utility employees and customers receive no benefit from the higher utility bills that result from an unusually hot summer. Similarly, customer growth, which commonly occurs without significant influence from company personnel may increase company earnings, thus triggering incentive payments. In fairness, since shareholders enjoy the benefits of customer growth between rate cases, they should also bear the cost of any incentive payments such growth may trigger. Finally, utility earnings may increase substantially if the utility is able to successfully argue for a higher ROE in a rate case proceeding. However, utility efforts to maximize ROE in a rate proceeding have little to do with improving overall employee performance across the company. If utility employee efforts are geared toward securing an *unreasonably* high ROE in a rate proceeding, the incentive mechanism actually would work to the detriment of the utility's customers.

(3) **Earnings-based incentive plans can discourage conservation.** When incentive payments are based on earnings, employees may not be as supportive of conservation programs designed to reduce usage if they perceive these programs could adversely impact incentive payment levels. To the extent earnings-based incentive plans discourage conservation and demand-side management programs, these plans would not be in the public interest. This point is especially important in light of the growing focus on energy efficiency at both the national and state level.

(4) **The utility and its stockholders assume none of the financial risks associated with incentive payments.** Ratepayers assume the risk that the amounts collected through rates for incentive payments will instead be retained by the utility whenever targeted increases are not reached. Employees assume the risk that the incentive payments will not be made in a given year. However, the utility and its stockholders assume no risk associated with these payments. Instead, the company's only responsibility is to decide who gets the money, the stockholders or the employees.

(5) **Incentive payments based on financial performance measures should be made out of increased earnings.** Whatever the targets or goals may be that trigger an incentive payment, when the plan is based in whole or in part on financial performance measures, there is always a financial benefit to the company that comes from achieving these objectives. This financial benefit

should provide ample funds from which to make the payment. If not, the incentive plan was poorly conceived in the first place. As such, employees should be compensated out of the increased earnings, and not through rates.

(6) **Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition.** When utilities are allowed to embed amounts for incentive payments in rates, that money is available to the utility not only to pay the incentive payment when financial performance goals are met but also to supplement earnings in those years when the company does not perform well. In those years when financial performance measures are met, the increased earnings of the company provide ample additional funds from which to make the incentive payments to employees, and the incentive payment amount embedded in rates is not needed. In those years when financial performance measures are not met and the incentive payments are not made, the amount embedded in rates for incentive payments acts as a financial hedge to shelter the poor financial performance of the company.

Even though regulators routinely exclude financial-based incentive compensation payments based on one or more of the reasons outlined above, this does not mean that regulated companies will not continue to offer financial-based incentives to their employees. They do. However, when a financial-based incentive package is properly constructed, there will be ample increased earnings to fund these payments. Thus, ratepayers do not need to subsidize incentive compensation plans designed to enhance financial performance. Further, as I discuss later in this testimony, there is no evidence that utilities discontinue these plans when they are not recovered in rates.

Q. IS THERE EVIDENCE THAT MORE OF THE ANNUAL INCENTIVE PLAN COSTS MAY BE TIED TO FINANCIAL PERFORMANCE THAN THE 52% IDENTIFIED BY THE COMPANY AS <u>DIRECTLY</u> TIED TO FINANCIAL GOALS?

A. Yes. The short-term incentive plan also includes goals that have an indirect financial benefit to Company earnings, such as spending level goals, cost constraint goals, reliability goals, and safety goals. These indirect financial goals are viewed by some commissions as having sufficient benefit to ratepayers to include them in rates. For example, while Texas and Nevada both exclude all incentives tied to earnings and Earnings Per Share ("EPS"), these commissions will often allow incentives tied to cost constraint and budgetary goals.

Gulf's short-term plan also includes an overall funding restriction on incentive payments that is directly related to Company earnings, as set forth in Gulf's Response to Citizens' Interrogatory No. 14, Bates Stamp Page No. 130140-OPC-POD-14-4. This means that <u>all</u> incentive payments are at least indirectly tied to the financial success of the Company each year. From a ratemaking perspective, this raises concerns. Under this approach, dollars included in rates for incentive payments could be confiscated by the utility and redirected to its shareholders in any year when profits are not sufficiently high in the Company's opinion. This means that from a ratemaking perspective the entire amount of incentive payments could be viewed as tied to financial performance to some extent.

Q. DO YOU KNOW OF INSTANCES WHERE COMMISSIONS HAVE DISALLOWED THE ENTIRE AMOUNT OF A UTILITY'S INCENTIVE PAYMENTS BECAUSE THE PAYMENTS WERE TIED TO AN EARNINGS FUNDING MECHANISM?

A. Yes. In Oklahoma, on two occasions the OCC disallowed 100% of the ONEOK, Inc., annual incentive plan for regular employees because, although many of the goals were purportedly customer-related goals, actual funding of the incentive payments was dependent upon the financial success of the company each year. *See* OCC Cause Nos. PUD 91-1190 and PUD 2004-610.

Q. HOW IS INCENTIVE COMPENSATION TYPICALLY TREATED IN JURISDICTIONS IN WHICH YOU REGULARLY PRACTICE?

A. The states in which I have significant personal experience with incentive plans all follow the majority rule that excludes incentive expense associated with financial performance measures. As a practical matter, this means that some portion of all incentive plans are excluded in these jurisdictions, as set forth in the summaries below:

In Nevada, the Public Utilities Commission of Nevada ("Nevada PUC") did not follow a consistent policy on incentives until 2008. In the 2008 Nevada Power Company ("Nevada Power") rate case, the Nevada PUC excluded the portion of the short-term plan directly related to financial performance and 100% of the long-term plan because it was all related to financial performance, based on the fact that these costs mainly benefit shareholders, as set forth in Nevada PUC's Final Order in Docket No. 08-12002. Since then, the Nevada PUC has consistently followed this approach for both Nevada Power and Sierra Pacific Power Company ("Sierra Pacific"). See, for example, Nevada PUC's Order in Docket No. 11-06006. In Sierra Pacific's current 2013 rate case, Nevada Docket No. 13-06002, the utility has adjusted out the portion of the short-term plan related to financial performance and 100% of the long-term plan. Both companies continue to pay short-term and long-term incentive compensation related to financial performance measures but do not seek to recover these costs in rates.

In Oklahoma, the Oklahoma Corporation Commission ("OCC") also excludes incentive payments tied to financial performance. From a practical perspective this means that all long-term plans are excluded as well as some portion of the annual short-term plans. In recent years, the OCC has not tried to determine the precise portion of the annual short-term plans tied to financial measures but has instead excluded 50% of the costs of these plans. On two separate occasions, in Cause Nos. PUD 91-1190 and PUD 2004-610, the OCC excluded 100% of the gas utility's short-term incentive plan costs because the overall funding mechanism for the plan was tied to corporate earnings. Similarly, 100% of the costs of long-term plans were excluded in American Electric Power-Public Service of Oklahoma ("AEP-PSO") Cause No. PUD 06-285, Oklahoma Gas & Electric ("OG&E") Cause No. PUD 05-151, and Oklahoma Natural Gas Company ("ONG") Cause No. PUD 04-610. Although incentives are routinely excluded, all of the major utilities in Oklahoma continue to pay both short-term and long-term incentive compensation related to financial performance measures, but they do not include these costs in rates.

In Texas, incentive payments tied to financial performance measures are excluded. This means that some portion of most short-term plans and all of the long-term plans are disallowed for ratemaking purposes. In the Entergy Texas, Inc. ("ETI") pending 2013 rate case, ETI is not seeking recovery of its financial-based short and long-term incentives. All of the utilities I audit in Texas continue to offer both short and long-term financial-based incentives; however, they do not recover these costs in rates.

In Utah, incentive costs associated with financial performance measures are all excluded. The rule is followed so closely that the major electric utility no longer submits the cost of its financial-based incentive plans for rate recovery. The utility continues to offer these plans, but does not seek to include them in rates.

Q. HAVE YOU SURVEYED HOW INCENTIVE COMPENSATION IS TREATED IN OTHER STATES?

A. Yes. The Garrett Group first conducted an Incentive Survey of the 24 Western States in 2007. This study was updated in 2009 and again in 2011. The results of this study show that a clear majority of the states follow the financial-performance rule, where incentive payments associated with financial performance are not allowed in rates. Some states disallow incentive pay using other criteria. None of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule.

Q. WHY DO YOU THINK THE RESULTS OF THIS SURVEY MAY BE HELPFUL TO THIS COMMISSION?

A. The incentive compensation survey presents the policies and positions adopted by regulators in other jurisdictions on incentive compensation issues. This information will help the Commission evaluate the Company's claim that financial-based incentives are necessary for the Company to attract and retain qualified personnel. As shown in the survey summary below, no state in the 24-state survey allows recovery of long-term financial-based incentives, and virtually no state allows short-term financial-based incentives. This evidence directly contradicts the Company's argument that Gulf must *recover these costs in rates* in order to attract and retain qualified personnel.

Although utilities in other jurisdictions generally pay financial-based incentives, virtually none of those utilities recover those incentive costs in rates. Thus, my review of the ratemaking policies in other states reveals that this Commission will not put Gulf at a competitive disadvantage when it excludes Gulf's financial-based incentive costs from rates. In fact, when the Commission excludes Gulf's financial-based incentive costs from rates, the Commission puts Gulf on an even playing field with other utilities with respect to compensation costs.

Even if one assumes the Company needs to provide these incentives in order to attract and retain qualified personnel, it does not follow that ratepayers should bear the burden of the Company's financial-based incentive compensation costs. The assertion that the Commission must include these costs in rates, otherwise the Company will not be able to make the payments and, therefore, will not be able to attract and retain qualified personnel, simply misstates reality. In my experience, every utility company about which I have testified to continues to make financial-based incentive payments as part of their overall compensation – even though regulators routinely exclude these costs. The survey reveals that regulators routinely exclude the costs of financial-based incentive programs from rates and, as such, this Commission will not put Gulf at a competitive disadvantage if it similarly excludes Gulf's financial-based incentives.

Q. PLEASE SUMMARIZE THE RESULTS OF THE GARRETT GROUP'S INCENTIVE COMPENSATION SURVEY OF THE 24 WESTERN STATES.

A. The summary of the results of the survey are shown in the table below. The complete survey, along with a description of the treatment in each state with supporting cases and regulations, is set forth at **Exhibit MEG-2** attached to this testimony.

Table 3: Incentive Compensation Survey Summary			
States that follow the financial-performance rule:			
• Arizona	• Idaho	• Nevada	• South Dakota
• Arkansas	• Kansas	• New Mexico	• Texas
• California	• Louisiana	• North Dakota	• Utah
• Colorado	• Minnesota	• Oklahoma	• Washington
• Hawaii	• Missouri	• Oregon	• Wyoming
States where Incentive Compensation has not been a recent litigated issue:			
• Alaska	• Iowa	• Montana	• Nebraska

In twenty (20) states where the issue of incentive compensation has been decided in a recent litigated rate case, the commissions have generally followed the financial-performance rule, where financial-based incentives are excluded. In three states, the issue has not been recently raised. In one state, Nebraska, the commission does not regulate any investor-owned electric utilities.

Q. WHY IS THE DISTINCTION BETWEEN FINANCIAL PERFORMANCE MEASURES AND OPERATIONAL MEASURES IMPORTANT FOR INCENTIVE COMPENSATION ANALYSIS?

A. When incentive compensation payments are based on financial performance measures, the compensation agreement between shareholders and employees could be loosely stated in this manner: "if you will help increase shareholder earnings, we will pay you a bonus." The intended beneficiaries to this agreement are the shareholders and the employees. Ratepayers have little stake in this agreement; therefore, they should not bear the costs that result from such an agreement. If, instead, the agreement were stated in this manner: "if you will help increase reliability and quality of service to the customers, we will pay you a bonus," then ratepayers would have a stake in the agreement, and could share in a portion of the costs. (Of course, the problem with this agreement is that ratepayers would be paying the utility to do something it is already obligated to do.) However, so long as some portion of the incentive plan is designed to increase earnings, that portion of the plan should be funded out of the increased earnings the plan helps produce.

Q. DOES IT MATTER THAT THE COMPANY'S TOTAL COMPENSATION PACKAGE IS SET NEAR THE MEDIAN LEVEL OF BENCHMARKED COMPENSATION?

A. No. It may matter that the Company's base pay levels are set at or near median benchmark levels for base pay; however, it does not matter that the Company's financial-based incentives are set at a reasonable level. The *reasonableness* of a particular cost has no bearing on the initial ratemaking decision of whether that cost should be included for ratemaking purposes. Reasonableness only comes into the evaluation *after* one has determined that a particular cost is includible. If an expense, by its nature, is not properly recoverable through rates – such as financial-based incentive compensation expense – it does not matter whether the amount paid for that cost was a reasonable amount. Regulators exclude the entire amount of the cost regardless of the amount paid. If a cost is, by its nature, an excludible cost, then the reasonableness of the cost level does come into the evaluation.

Although regulated utilities frequently advance this argument to support the inclusion of incentive pay in utility rates, regulators routinely reject it. It does not matter that the amount paid for a cost is reasonable if the cost itself is of a type or nature that is not recoverable in rates, as in the case of financial-based incentive compensation. Similarly, even if the Company's overall compensation structure is reasonable, this does not affect the policy-driven analysis as to whether certain financial-based incentive costs should be borne by the shareholders rather than the ratepayers. It has been my experience that utilities routinely show that their total compensation packages, including financial-based incentives, are set at or near median market levels, and that commissions nevertheless routinely disallow their financial-based incentive pay without regard to their total compensation package arguments. This is certainly true of the utility companies I have dealt with in the states of Oklahoma, Texas, Nevada and

Arkansas. All of these utilities continue to offer financial-based incentive pay, but none of them recover these costs in rates. The 24-state survey shows that this is likely true for most utilities.

Q. ARE THERE REASONS WHY THE COMMISSION COULD CONSIDER A LARGER ADJUSTMENT TO INCENTIVE PAY?

A. Yes. Although incentive payments related to customer satisfaction goals are generally allowed in rates, this treatment presumes that the incentive payments paid for these goals are actually resulting in good customer relations. The Company made substantial incentive payments based on employees achieving some perceived acceptable level with respect to customer satisfaction goals; however, these payments seem inconsistent with Gulf Power's ratings in the annual J.D. Power and Associates Report on Customer Satisfaction for Residential customers. The J.D. Power and Associates Reports are widely recognized and unbiased.

The J.D. Power Report ranks utilities in the 50 states based on customer satisfaction measures. Gulf Power has not fared well in these rankings over the past 5-year period. If customer-related incentive payments were actually improving customer relations, one would expect to see improvements in the Company's ratings in an independent customer satisfaction survey such as the J.D. Power Report. However, over the past 5-year period, 2009-2013, Gulf Power's customer satisfaction rankings steadily declined from 2009 through 2012 and then rose only slightly in 2013, but to nowhere near where they were in 2009. In 2009, the Company was in the top quartile of companies in its region; however, by 2012 the Company had fallen to the bottom quartile, placing 24th out of 30 companies. In the 2013 report, Gulf Power ranked 15th out of 30, or barely above average. The table below shows Gulf Power's rankings in the South Region from 2009 through 2013.

Table 4: Gulf Power's Rankings in J.D. Power Annual Residential Customer Satisfaction Surveys 2009 - 2013		
Year	Ranking	No. of Utilities in Region
2009	7th	28 companies
2010	15th	27 companies
2011	17th	30 companies
2012	24th	30 companies
2013	15th	30 companies

The poor showing of Gulf Power in an independent, objective customer satisfaction evaluation report brings into question whether ratepayers should be required to fund the Company's incentive payments based on customer satisfaction when the Company's customer relations have been getting worse, not better, over the past 5-year period.

Q. WHAT PORTION OF THE ANNUAL SHORT-TERM INCENTIVE PERFORMANCE PAY PLAN IS TIED TO CUSTOMER SATISFACTION GOALS?

A. According to the Company's Response to Citizens' Interrogatory No. 80(k), 30% of the Operational Goals, which are 48% of the plan, are tied to Customer Satisfaction measures. Thus, according to the Company's figures, 14.4% of the annual short-term incentive Performance Pay Plan is tied to Customer Satisfaction measures. This means that about $2,086,992 of the Company's $14,493,000 annual plan costs are tied to Customer Satisfaction. Based upon this independent survey data, the Company's customer satisfaction levels have been in the lower quartiles over the last 5 years. As such, it is appropriate at this time to disallow a portion of the incentives based on customer satisfaction. I recommend that the Commission disallow 50% of that portion of the incentive that is based on customer satisfaction, or $1,043,500 ($2,086,992 x 50%).

Q. WHAT ADJUSTMENT DO YOU RECOMMEND FOR THE COMPANY'S ANNUAL SHORT-TERM INCENTIVE PERFORMANCE PAY PLAN COSTS?

A. I recommend that the Commission disallow short-term incentive costs identified by the Company as directly tied to financial performance. I believe this is a conservative recommendation because, in my view, the Commission could find that all of the short-term incentives costs are either directly or indirectly tied to financial performance as a result of the shareholder-related funding restriction. Also, I believe that the Commission should exclude 50% of the costs of the annual plan that are associated with Customer Satisfaction measures, because the Company has not shown measurable improvement in this area in the past 5-year period based upon the independent J.D. Power and Associates Report.

As a result, I recommend that the Commission exclude $7.536 million from pro forma operating expense for incentives tied directly to financial performance measures, and should exclude an additional amount, for this rate case only, of $1.043 million for incentives tied to Customer Satisfaction measures. The two recommended adjustments to short-term incentive expense are set forth below and in **Exhibit MEG-3**, Schedule C-3.

Description of OPC's Adjustments	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Incentives related to Financial Performance Measures	C-3	$7,536	$7,390
50% of Incentives related to Customer Satisfaction	C-3	$1,043	$1,023
Total Adjustments to Short-Term Incentives	C-3	**$8,579**	**$8,413**

Q. IS A RELATED ADJUSTMENT FOR PAYROLL TAXES NEEDED?

A. Yes. The two short-term incentive adjustments reduce payroll expense, which gives rise to a reduction in associated payroll taxes. The Company's FICA tax expense level should be reduced by 7.65% of $7,536,000, or $576,500, for the portion of the short-term Performance Pay Plan related to financial performance measures, and by 7.65% of $1,043,500, or $79,800, for the short-term Performance Pay Plan related to the customer service disallowance. This results in a total payroll tax adjustment of $656,000 on a total company basis. The adjustment is shown below and on **Exhibit MEG-3**, Schedule C-3.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Payroll Tax Adjustment related to ST Incentives	C-3	$656	$643

B. Long-Term Incentives

Q. **DOES THE COMPANY PROVIDE LONG-TERM OR STOCK-BASED INCENTIVE COMPENSATION TO ITS EMPLOYEES?**

A. Yes. Higher paid employees of the Company are provided with additional incentive compensation through the Stock Options and the Performance Share Program, which provides stock options and other stock–based awards to executives and other employees of the Company.

Q. **HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO INCLUDE LONG-TERM INCENTIVE COMPENSATION EXPENSE IN RATES?**

A. Yes. The Company seeks to include $3,160,000 in the cost of service for long-term and stock-based incentive compensation expense. The Company includes 100% of Gulf's and SCS' long-term incentive plan compensation. The Company makes no adjustment to remove any of its test year stock-based incentives. The Company's proposed inclusion of financial-based incentive compensation is addressed in the testimony of Gulf witness Garvie. At page 12 of his testimony, Mr. Garvie asserts that incentive programs tied to cost controls, profitability and stock price help companies attract, motivate and retain talented employees, and that without financial-based incentives, employees would not be motivated to look after the financial health of the company.

The inclusion of financial-based incentives is also proposed in the testimony of Gulf witness R. Scott Teel. At page 30 of his direct testimony, Mr. Teel asserts that stock-based incentives provide "the Company's management employees with the incentive to ensure that their actions and decisions meet investor expectations not just this year but on a sustainable basis." Gulf's long-term incentive expense levels proposed for inclusion in cost of service are set forth in the table below:

Table 5: Total Long-Term and Stock-Based Incentive Compensation			
Incentive Compensation Plans	Gulf Power	SCS Allocated	Total Included in Cost of Service
Performance Share Plan	$772,000	$535,000	$1,307,000
Stock Options	1,138,000	715,000	$1,853,000
Total Long-Term Incentives	**$1,910,000**	**$1,250,000**	**$3,160,000**

Q. **DO YOU RECOMMEND THE INCLUSION OF THE LONG-TERM AND STOCK-BASED INCENTIVE EXPENSE IN RATES?**

A. No. Incentive compensation payments to officers, executives and key employees of a utility company are generally excluded for ratemaking purposes, and I agree with this treatment. Stock-based compensation in particular is excluded in most jurisdictions because stock-based compensation is, on its face, tied to financial performance. Since officers of any corporation have a duty of loyalty to the corporation itself and not to the customers of the company, these individuals typically put the interests of the company first. Undoubtedly, the interests of the company and the interests of the customer are not always the same, and at times, can be quite divergent. This natural divergence of interests creates a situation where not every cost associated with executive compensation is presumed to be a necessary cost of providing utility service. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs are better borne by the utility shareholders.

It has been my experience that some utilities treat supplemental executive compensation as a below-the-line item even without a Commission order directing them to do so. Also, long-term executive incentive plans, such as the stock-based and stock performance-based plans, are specifically designed to tie executive compensation to the financial performance of the company. This is done to further align the interest of the employee with those of the shareholder. Since the compensation of the employee is tied over a long period of time to the company's stock price, it creates an incentive for the employee to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders.

It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage utility executives to put the financial interest of the shareholders first, especially when the financial interest of the shareholder is directly bolstered by increases in utility rates.

Q. DO YOU AGREE WITH MR. GARVIE THAT EARNINGS-BASED AND EQUITY-BASED INCENTIVES ALIGN THE INTERESTS OF SHAREHOLDERS AND RATEPAYERS?

A. No. His arguments certainly do not apply to rate regulated monopolies that can increase earnings through commission-petitioned rate increases. While higher rates may be financially beneficial to shareholders, they can be financially detrimental to ratepayers. Clearly, it would be inappropriate to force ratepayers to pay for incentives that motivate executives to increase earnings through either higher rates in a rate case or expense reductions made immediately following a rate case.

Q. IS YOUR RECOMMENDATION TO EXCLUDE EXECUTIVE INCENTIVE COMPENSATION CONSISTENT WITH THE TREATMENT OF LONG-TERM INCENTIVES OF OTHER STATES IN WHICH YOU HAVE EXPERIENCE WITH INCENTIVE ISSUES?

A. Yes. Oklahoma, Nevada, Texas, Arkansas and Utah all generally exclude incentive compensation tied to financial performance measures. This means that 100% of the long-term incentive and stock-based plans are routinely excluded. In Texas, Oklahoma and Arkansas, the utilities still incur these costs; however, these commissions consistently exclude 100% of the utilities' long-term incentive and stock-based plans. In Nevada, Sierra Pacific and Nevada Power both still pay long-term incentives but no longer seek recovery of these costs in rates. Likewise, in Utah, PacifiCorp voluntarily removes all of the costs associated with long-term incentive compensation. In PacifiCorp's last two general rate cases, in Utah PSC Docket Nos. 07-035-93 and 08-035-38, the utility did not seek recovery of its long-term executive compensation plans. The table below sets forth several recent litigated commission decisions for long-term incentive and stock compensation plans for the major utilities in these states.

TABLE 6: LONG-TERM INCENTIVE TREATMENT IN TEXAS, OKLAHOMA, ARKANSAS, NEVADA AND UTAH		
Utility Company	**Amount Excluded**	**Docket Number**
Entergy Texas	100% Excluded	Docket No. 39896
AEP/PSO	100% Excluded	Cause No. PUD 200800144
Oklahoma Gas & Electric	100% Excluded	Cause No. PUD 200500151
Oklahoma Natural Gas	100% Excluded	Cause No. PUD 200400610
Nevada Power	100% Excluded	Docket No. 08-12002
Entergy Arkansas	100% Excluded	Docket No. 06-101-U
PacifiCorp	100% Excluded	Docket No. 08-035-38

Q. HOW IS LONG-TERM INCENTIVE AND STOCK COMPENSATION TREATED IN OTHER STATES?

A. The results of the Garrett Group Incentive Compensation Survey show that most states follow guidelines similar to those described above for Texas, Oklahoma, Arkansas, Nevada and Utah, where incentive pay associated with financial performance is not allowed. This means that long-term incentives and executive stock compensation are <u>not allowed</u> in most states. A synopsis of the survey results from each state is set forth at **Exhibit MEG-2**, and the treatment of long-term executive incentives in each state is underlined. According to the survey, the following western states exclude all or virtually all executive incentive pay: Arkansas, California, Colorado, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah and Wyoming. Other states like Arizona, Hawaii, and Washington apply the *financial performance* rule, which has the effect of excluding executive incentives, especially stock-based awards. (In the other four states, Alaska, Iowa, Montana and Nebraska, the commissions there have not decided the issue of incentive compensation in a recently litigated rate case.)

Q. WHY IS THE TREATMENT OF LONG-TERM INCENTIVES IN OTHER STATES IMPORTANT TO CONSIDER?

A. When utilities seek to include executive incentives in rates, they generally argue that long-term incentives are part of an overall compensation package that is designed to attract and retain qualified personnel. Since other utilities offer incentive plans to their executives, the utilities claim that a company would run the risk of not being able to compete for key personnel if it did not offer a comparable plan.

The treatment of long-term incentives in other states demonstrates that when utilities, such as Gulf, compete with other utilities for qualified executives, and the executive incentive compensation plans of the other utilities are <u>not</u> being recovered through rates, <u>Gulf is not put at a competitive disadvantage when its executive incentive compensation costs are excluded as well</u>. Since most states exclude executive incentive pay as a matter of course and most others exclude executive incentives as a practical matter, Gulf would actually be provided an unfair advantage if the costs of its executive plans were included in rates. The fact that other utilities offer executive incentive plans is not relevant; what is relevant is the fact that <u>other utilities are not recovering the costs</u> of these plans in rates. The Nevada PUC articulated this important ratemaking concept in its order disallowing Nevada Power's long-term incentive plan in one of the utility's general rate cases. In the Final Order in Docket 08-12002, at paragraph 549, the Nevada PUC stated:

> Therefore the Commission accepts BCP's and SNHG's recommendations to disallow recovery of expenses associated with LTIP. Both parties provide a valid argument that this type of incentive plan is mainly for the benefit of shareholders. Further, both BCP and SNHG provide examples of numerous other jurisdictions that do not allow the recovery of these costs and, <u>therefore, disallowance in this instance would not place NPC in a competitive disadvantage.</u> (Emphasis added).

Another problem with the Gulf's argument is that when an incentive payment is based on achieving financial performance goals, there should be a financial benefit to the company that comes from achieving these goals. This financial benefit should provide ample additional funds from which to make the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not placed at a competitive disadvantage when incentive payments tied to financial performance are not collected through rates, because the funding for these payments should come out of the additional earnings the incentive plans help achieve.

Q. HOW IS LONG-TERM AND STOCK-BASED INCENTIVE COMPENSATION TREATED IN FLORIDA?

A. In Gulf's last rate case, in Order No. PSC-12-0179-FOF-EI in Docket 110138-EI, at page 94, all long-term and stock-based incentives were excluded. Similarly, in a recent FPL rate case the Commission disallowed all of the utility's long-term executive compensation. In its order, the Commission found that the long-term executive compensation program was designed to align the interest of the executive with that of the shareholder. In Order No. PSC-10-0153-FOF-EI, for Docket Nos. 080677-EI and 090130-EI at page 147, this Commission stated:

> We find that the entire executive incentive compensation program is designed to benefit the shareholders by creating long-term shareholder value. We find that the executive incentive compensation program is designed to place the interests of executives in the same light as that of shareholders, thus creating incentive to increase the value of FPL Group's shares. Because these programs are designed for the benefit of shareholders, those costs shall be borne exclusively by shareholders.

Q. HOW SHOULD THE COMMISSION TREAT LONG-TERM INCENTIVE COMPENSATION IN THIS CASE?

A. I believe the Commission should continue to follow the practice observed in Florida and in most other jurisdictions that excludes long-term incentive costs. In light of the overwhelming trend against including financial-based incentives in rates, and considering the current national economic downturn and the economic shortfalls being experienced by ratepayers everywhere, I believe the Commission should continue to follow the approach to incentive compensation that protects ratepayers against even the appearance of being forced to pay costs designed to increase shareholder wealth. A policy that includes incentive payments based on financial performance in rates, as proposed by the Company, has the effect of forcing ratepayers to become captive contributors to the financial prosperity of one company.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING WITH RESPECT TO THE COMPANY'S LONG-TERM INCENTIVE AND STOCK COMPENSATION COSTS?

A. My proposed adjustment removes (1) 100% of the cost of the Performance Share Program and (2) 100% of the costs of the stock option awards. These plans are based entirely upon the financial performance of the Company. Both plans are financial-based on their face. My adjustment removes the entire amount included in pro forma operating expense for these plans in the amount of $3,160,000. This adjustment is set forth below, and can be found at **Exhibit MEG-3**, Schedule C-3.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Adjustment related to Long-Term Incentives	C-3	$3,160	$3,095

C. Supplemental Executive Retirement Plan ("SERP")

Q. PLEASE DESCRIBE THE COMPANY'S SUPPLEMENTAL EXECUTIVE RETIREMENT PLANS.

A. The Company provides supplemental executive retirement plan ("SERP") benefits to highly compensated employees. These supplemental retirement plans for highly compensated individuals are provided because benefits under the general retirement plans are subject to certain limitations under the Internal Revenue Code ("Code"). As such, these types of plans are often referred to as *non-qualified* plans. Benefits payable under these non-qualified plans are typically equivalent to the amounts that would have been paid but for the limitations imposed by the Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $255,000 for the 2013 tax year. Retirement benefits on compensation levels in excess of the $255,000 limitation are paid through supplemental plans. Supplemental retirement plans for highly compensated employees are designed to provide benefits in addition to the benefits provided under the general pension plans of the company. According to Gulf's Response to Citizens' Request for Production of Documents No. 16, the Company has three non-qualified retirement plans for highly compensated employees:

- Supplemental Benefit Plan
- System Executive Retirement Plan
- Benefits Provided in Individual Agreements

The first two plans cover employees as determined by the plans' Administrative Committees. The third plan covers individuals that have executed individual agreements with the Company. Benefits are paid out of the general funds of the Company.

Q. WHAT AMOUNTS WERE INCLUDED IN PRO FORMA OPERATING EXPENSE FOR THE EXECUTIVE PENSION PLAN?

A. In its Response to Citizens' Interrogatory No. 7, the Company states that the amount of non-qualified supplemental retirement plan costs included in cost of service is $2,220,000.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO EXECUTIVE RETIREMENT BENEFITS?

A. I recommend that shareholders pay for the costs of the supplemental executive retirement plans. This means that ratepayers will pay for all of the executive benefits included in the Company's <u>regular</u> pension plans (*i.e.*, on salary levels <u>up to</u> $255,000), and shareholders will pay for the additional executive benefits included in the supplemental plans (*i.e.*, on salary levels <u>above</u> $255,000 for 2013). For ratemaking purposes, shareholders should bear the additional costs associated with supplemental benefits to highly compensated executives, since these costs are not necessary for the provision of utility service, but are instead discretionary costs of the shareholders designed to attract, retain and reward highly compensated executives.

This approach makes sense because officers of any corporation have a duty of loyalty to the corporation. As such, these individuals are required to put the interest of the company first. This creates a situation where not every cost associated with executive compensation is presumed to be a cost appropriately passed on to ratepayers. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs are better borne by the utility shareholders. For example, the Nevada PUC disallowed <u>all</u> SERP expense in Nevada PUC Docket Nos. 01-10001 and 03-10001. In Nevada Docket Nos. 06-11022 and 08-12002, a portion of the SERP payment was disallowed. Similarly, in Oklahoma, the OCC excluded AEP/PSO's supplemental retirement costs in that utility's last rate case, OCC Cause No. PUD 200600285.

Q. HOW IS SERP TREATED IN OTHER JURISDICTIONS IN WHICH YOU HAVE PROVIDED TESTIMONY ON SERP COSTS?

A. In Nevada, the PUC has disallowed SERP expense in Docket Nos. 01-10001, 03-10001, 06-11022, 08-12002, and 11-06006.

In Oklahoma, the OCC disallowed 100% of AEP/PSO's SERP expense in PSO's 2006 rate case, Cause No. PUD 200600285:

> q. <u>Employee Benefits-Supplemental Executive Retirement Plan ("SERP")</u>.
>
> PSO included $596,081 as Supplemental Executive Retirement Plan ("SERP") in its cost-of-service. The Commission adopts OIEC's proposal to remove the SERP Expense from the revenue requirement in this proceeding. The Commission adopts OIEC's recommendation that ratepayers pay for all of the executive benefits included in PSO's regular pension plans and that shareholders pay for the additional executive benefits included in the supplemental plan.

Again, in AEP/PSO's 2008 rate case Cause No. PUD 200800144, the OCC disallowed 100% of the Company's SERP expense.

> 11. Supplemental Executive Retirement Plan ("SERP")
>
> The AG and OIEC recommend reductions to reflect the elimination of SERP expense from PSO's cost of service. Staff proposed no adjustment to PSO's recommendation. SERP is AEP's non-qualified defined benefit retirement plan that PSO argued allows AEP the flexibility to attract and retain key employees and provides benefits that cannot be provided under AEP's qualified defined benefit plans. PSO stated that the combined plans, of which SERP is a part, allow employees to accumulate an appropriate level of replacement income upon retirement. According to PSO, SERP plans and other benefits are part of a market competitive benefits program for the utility industry and large employers in general. The Commission finds that the SERP expenses do not provide a benefit to the ratepayers of PSO and therefore adopts the recommendation of the AG and OIEC to deny recovery of these costs from PSO's ratepayers.

In Texas, in Entergy's last rate case, Docket No. 39896, the Texas Public Utility Commission disallowed all of the Company's SERP costs stating:

> 140. ETI provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $245,000 per year.
>
> 141. ETI's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the shareholders than the customers.
>
> 142. ETI's non-qualified executive retirement benefits in the amount of $2,114,931 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in ETI's cost of service.

Q. HAVE YOU INVESTIGATED HOW SERP IS TREATED IN OTHER STATES?

A. Although I have not conducted a comprehensive study of SERP treatment in other states, I am aware that SERP is disallowed in Oregon, Idaho, and Arizona in addition to the jurisdictions discussed above. In Oregon Public Utilities Commission ("Oregon PUC") Order No. 01-787, at page 44, the Oregon PUC stated:

> The Commission has not allowed recovery of SERP expenses in other utility rate cases. PacifiCorp has not persuaded us that it is necessary to pay SERP to hire and retain executive officers. The SERP costs are not allowed.

Similarly, in Idaho Public Utilities Commission ("Idaho PUC") Order No. 32196, in Rocky Mountain Power's Case No. Pac-E-10-07, the Idaho PUC stated:

> The Commission finds Staff's argument persuasive and finds it reasonable to disallow Company recovery of SERP costs of $2.6 million (total Company) in this case. The Company has not demonstrated that the costs are related to providing services to southeast Idaho. The responsibility for generous severance benefits for executives, we find, is the responsibility of the Company and its shareholders, not Idaho customers.

Q. WHAT IS THE AMOUNT OF THE SERP ADJUSTMENT?

A. The necessary adjustment to remove the cost of the non-qualified retirement plans from cost of service is $2,220,000, and is set forth in **Exhibit MEG-3**, Schedule C-4.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
SERP Adjustment	C-4	$2,220	$2,174

D. Payroll Expense

Q. WOULD YOU PLEASE DESCRIBE THE COMPANY'S PROPOSED ADJUSTMENTS TO PAYROLL-RELATED EXPENSES?

A. The Company proposed adjustments to increase payroll-related expenses to reflect pay raises that occurred in 2013 and are projected for 2014. In total, the Company seeks to increase its payroll expense by $3,746,858 associated with 2.50% pay raises, and other increases in 2013; and by $2,241,963 in 2014 for 3.00% pay raises offset by the Hiring Lag adjustment.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED INCREASES TO PAYROLL FOR THE FORECASTED TEST YEAR?

A. Generally, I do not agree with adjustments that increase rates for selective events that occur in the future. This type of piecemeal ratemaking can be abused by ignoring or minimizing decreases to expenses that may also occur. During the period that prospective rates are in effect, the utility bears the risk that cost levels may increase over test-year levels and enjoys the financial benefits that result if actual costs are lower. For example, utilities are allowed to retain the additional revenue that results from load growth. Likewise, utilities are allowed to retain the increased earnings that result from cost savings measures, such as reductions in the company's workforce and increased productivity.

In return for these benefits, however, utilities are expected to bear the risk that cost levels may, in fact, increase. These increases occur, for example, when higher wages outpace the company's productivity gains and other cost control measures. If the

Commission approves a proposed adjustment to increase rates for a particular cost that may increase in the future without recognizing related offsetting cost decreases, the utility has successfully, and inappropriately, shifted a portion of its responsibility in the ratemaking arrangement to ratepayers. When the utility uses a forecasted test year, the proposed cost increases must be carefully scrutinized to ensure that all issues are addressed and that increases reflect the company's diligent efforts to keep cost increases under control.

Q. ARE THERE SPECIFIC REASONS WHY THE COMPANY'S PROPOSED TEST YEAR PAY INCREASE, AS CALCULATED, IS INAPPROPRIATE?

A. Yes. While it may seem apparent that pay raises implemented in the future test year would increase payroll expense levels, other events over the same period of time could decrease payroll levels by even greater amounts. For example, workforce reductions can have a far greater impact on payroll expense than a pay raise would. Other more subtle changes can decrease payroll expense levels as well.

Even with a stable workforce, employees are being added to and removed from the payroll registers on a fairly regular basis over the course of the test year. Since retiring employees are generally paid much more than new hires, overall payroll expense levels can decrease significantly if higher paid employees leave the company and are replaced with employees paid at lower levels. Also, changes in a company's capitalization percentage during a period of higher construction can reduce payroll expense levels, even with no reduction in overall payroll costs. Each of these potential reductions in payroll expense can more than offset the anticipated increase from an annual raise. While the Company included an adjustment for hiring lag, it did not recognize the impact of employee turnover and improvements in productivity.

Q. WHAT PAYROLL-RELATED FACTORS COULD OFFSET THE COMPANY'S PROPOSED SALARY INCREASES?

A. In general, most businesses are able to improve the effectiveness of their work force over time, resulting in increased productivity. Improvements in technology and sound management practices can increase the productivity of a work force. These improvements in productivity are generally rewarded through annual merit increases. With improved performance comes increased efficiency. In effect, employees with experience become better at what they do. This translates into a higher quality work product produced in a shorter amount of time. Merit raises and increased productivity generally go hand in hand.

Q. WHAT IS PRODUCTIVITY GROWTH AND WHY IS IT IMPORTANT IN THIS CASE?

A. In economic terms, productivity is the ability to produce more with less input. Productivity is measured by comparing the amount of goods and services produced with the inputs used in the production of a product. Specifically, labor productivity is the ratio of the output of goods and services to the labor hours devoted to the production of the output. The Bureau of Labor Statistics ("BLS") reports significant growth in labor productivity over the past few years.

Q. IS THERE EVIDENCE THAT PRODUCTIVITY IMPROVEMENTS ARE GENERALLY SUFFICIENT TO OFFSET PAY INCREASES?

A. Yes. The BLS publishes quarterly employment cost data that includes productivity information. The most recent release of 2013 2nd quarter data indicates that the manufacturing sector experienced productivity improvements of 1.9% in the last four quarters. This compares to an annual average improvement of 1.7% from 2007 through 2012 (*See* Bureau of Labor Statistics, News Release, September 5, 2013, *Productivity and Costs*, page 2). When a forecasted test year is used to project increased labor costs, an adjustment for offsetting productivity gains should be included in the analysis.

Q. WHAT PRODUCTIVITY ADJUSTMENT COULD BE CONSIDERED USING THIS BUREAU OF LABOR STATISTICS INFORMATION?

A. An adjustment should be made for projected productivity gains. As a conservative estimate, I recommend an adjustment based on BLS' six-year average long-term productivity gains for the manufacturing industry of 1.7% (which is *below* the 1.9% increase in productivity the manufacturing sector achieved over the last four quarters). Utilizing a 1.7% productivity adjustment for 2013 and 2014 would decrease Gulf's payroll expense by $2,806,790. This amount is calculated based on the information provided by the Company in its Response to Citizens' Interrogatory No. 1, as follows: [($81.371M X 1.7%) + ($83.735M X 1.7%) = $2.806M]. This productivity adjustment to payroll expense should be offset by the hiring lag adjustment of $557,736, which is set forth in the testimony of Gulf witness Richard J. McMillan, at page 12, and in related Exhibit RJM-1, Schedule 5. After making the required adjustment for the hiring lag, Citizens' proposed net productivity adjustment is a reduction to payroll expense in the amount of $2,248,000.

Q. HAVE OTHER UTILITY COMMISSIONS CONSIDERED ADJUSTMENTS TO RECOGNIZE PRODUCTIVITY IMPROVEMENTS?

A. Yes. In its 2009 California rate case, A.09-12-020, Pacific Gas & Electric Company included a productivity factor adjustment of 0.5% of non-fuel revenues. This is a large adjustment, considering that the adjustment was applied to revenues and not to expense items. This format of productivity recognition continues to be used in California rate cases. Similarly, the New York Public Service Commission ("New York PSC"), Case 11-E-0590, July 12, 2012 applied a 1% productivity adjustment to labor, payroll reimbursement, related benefits, and payroll taxes, at the same time noting that this was consistent with New York PSC policy.

In Utah, Docket No. 07-035-93 the Utah Public Service Commission acknowledged that a productivity adjustment should offset payroll costs if a future test year is used, stating:

> We concur with the Division a forecast test period, unlike an historic test period, **must take labor productivity increases and other efficiency gains into account in the determination of the revenue requirement**. In this case we acknowledge the Company's automated meter reading program will increase productivity in the test period. In this docket, we make no further adjustment for productivity beyond what is incorporated by the Company's projections. Further, it is our expectation the Company will continue to look for ways to increase productivity and efficiency in the future. (Emphasis added).

Q. WOULD A PRODUCTIVITY ADJUSTMENT BE APPROPRIATE IN THIS CASE?

A. The delayed economic recovery has resulted in substantial hardship on many utility customers. Many customers are currently unemployed and many more are under-employed. In the private sector, companies on average are controlling payroll costs relative to output. In other words, pay raises are being offset with productivity gains. Good management and conscientious efforts by employees are essential to keep costs in check. In this economic climate, it would be reasonable to require utilities to achieve similar productivity gains to offset proposed pay increases.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PAYROLL COST ADJUSTMENT.

A. The Company has considered only limited elements of payroll costs in its proposed payroll adjustment: the budgeted and forecasted pay increases and the required hiring lag adjustments. The Company failed to consider any offsetting adjustment for productivity. I recommend a productivity offset to the increases in wages and salaries. Requiring the Company to recognize productivity gains is particularly appropriate at this time in light of the current economic hardship most ratepayers now face. Citizens' proposed productivity offset would reduce the cost of service by $2,248,000 on a total company basis. This adjustment is set forth below and in **Exhibit MEG-3**, Schedule C-5.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Payroll Expense (Productivity) Adjustment	C-5	$2,248	$2,205

Q. DOES THE OPC'S PRODUCTIVITY ADJUSTMENT ALSO REQUIRE AN ADJUSTMENT FOR ASSOCIATED PAYROLL TAXES?

A. Yes. The productivity adjustment reduces the payroll level, which gives rise to a reduction in associated payroll taxes. The Company's FICA tax expense level should be reduced by 7.65% of the $2.248 million productivity adjustment, for a payroll tax adjustment of $172,000 on a total company basis. This adjustment is shown below and in **Exhibit MEG-3**, Schedule C-5.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Payroll Tax Adjustment related to the Payroll Expense (Productivity) Adjustment	C-5	$172	$169

E. Employee Medical Expense

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO FUTURE MEDICAL COSTS?

A. The Company's forecasted 2014 test year includes $10,854,234 for (Active Employees) Medical expense. This is an increase of $2,126,139 over the recorded December 31, 2012 expense level of $8,728,095. This represents an increase of 24.36% for the 24-month forecast period, or 12.18% annually. In support of its requested increase, the Company cites a significant upward trend in healthcare costs in recent years and references a statement from its consultant, AON Hewitt, that current trends show rates for the Company's medical benefits are anticipated to increase by 8.5% in 2013 and by

10.0% in 2014. The Company's projection also relies on an increase in the number of projected employees.

Q. ARE YOU AWARE OF OTHER INDEPENDENT CONSULTING FIRMS THAT PROVIDE HEALTH CARE COST INFORMATION FOR COMPARISON PURPOSES?

A. Yes. Towers Watson is a nationally recognized firm that has, for many years, provided forecasts of health care costs. It should be noted that Towers Watson is also the firm that the Company relied upon to review its compensation plans, as noted in the direct testimony of Gulf witness Garvie, at page 16.

Q. DOES THE TOWERS WATSON FORECAST OF HEALTH CARE COSTS DIFFER FROM THOSE RELIED UPON BY THE COMPANY?

A. Yes. In 2013, Towers Watson and the National Business Group on Health ("NBGH") published their 18th annual *Employer Survey on Purchasing Value in Health Care.* Towers Watson states that the health care cost trend has stabilized at between 5% and 7% over the past 5 years ending 2012. The report also projects that this trend will continue into the near future. The report states that the health care cost estimate for 2013 is also within the range of 5% and 7%. The report attributes much of the trend to employer efforts to aggressively manage health care benefit program performance.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND WITH RESPECT TO THE COMPANY'S PROJECTED MEDICAL EXPENSE?

A. Based upon the average of the Towers Watson 2012 high range of 7.0% escalation observed over the past 5 years and projected for 2013, I recommend an adjustment to reduce projected 2014 medical expense costs from $10,854,000 to $10,467,000, for an adjustment amount of $387,000 to medical expense.

Q. DOES YOUR ADJUSTMENT TAKE INTO CONSIDERATION THE COMPANY'S PROJECTED INCREASE IN ITS WORKFORCE TO 1,478 EMPLOYEES IN 2014?

A. While I do not necessarily agree that the Company will need that number of employees, I did use (for purposes of this adjustment) the Company's projected number of 1,478 employees. The number of employees for the year 2012 averaged 1,411. In order to include the greater employee count, I developed an employee growth factor by dividing the projected 2014 employee count by the 2012 average. This resulted in a gross up factor of 1.0475 for projected medical expenses.

Q. HOW MUCH DOES YOUR MEDICAL EXPENSE ADJUSTMENT REDUCE THE ALLOWABLE MEDICAL EXPENSE?

A. This medical expense adjustment will reduce the total company allowable medical expense by $387,000. This adjustment is set forth in **Exhibit MEG-3**, Schedule C-6.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Employee Medical Expense Adjustment	C-6	$387	$380

F. Directors And Officers Liability Insurance

Q. HAS THE COMPANY INCLUDED COSTS FOR DIRECTORS AND OFFICERS ("D&O") LIABILITY INSURANCE IN THE REVENUE REQUIREMENT?

A. Yes. As set forth in the direct testimony of Gulf witness Constance J. Erickson, page 11, the Company included the $95,000 premium paid for D&O insurance in the test year.

Q. PLEASE DESCRIBE THE COMMISSION'S APPROACH IN GULF'S LAST RATE CASE WITH RESPECT TO D&O LIABILITY INSURANCE.

A. In the Company's last rate case, the Commission determined that the D&O liability insurance costs should be shared equally between the shareholders and the ratepayers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THESE COSTS?

A. I have recommended that these D&O liability insurance costs be shared equally between the shareholders and the customers, as this is the ratemaking treatment adopted by the Commission in the last proceeding.

Q. THE COMPANY CONTENDS THAT THE SOUTHERN SYSTEM D&O COSTS ARE "ALREADY SPLIT" BETWEEN SCS SHAREHOLDERS AND CUSTOMERS. DO YOU AGREE?

A. No. The $95,000 premium is the amount attributable to Gulf's D&O liability insurance. The fact that SCS may have additional D&O premiums that are not attributable to Gulf does not mean that Gulf's ratepayers should bear all of its D&O insurance costs. The Company's approach attempts to allocate 100% of Gulf's D&O premium costs to the customers by including these costs in rates. This is contrary to the method utilized by the Commission in the last rate case.

Q. WHAT ADJUSTMENT DO YOU PROPOSE?

A. I recommend an adjustment to remove 50% of the $95,000 premium, which reduces the total cost of service by $47,500 (rounded to $48,000) as set forth below, and in **Exhibit MEG-3**, Schedule C-7.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Payroll Tax Adjustment related to the Payroll Expense (Productivity) Adjustment	C-7	$48	$47

SECTION IV. STORM DAMAGE ACCRUAL

Q. PLEASE DISCUSS GULF'S REQUEST TO INCREASE THE ANNUAL STORM DAMAGE ACCRUAL TO $9,000,000 PER YEAR.

A. Gulf witness Stephen P. Harris provided direct testimony presenting the results of his analysis of the Company's uninsured, hurricane-related loss risk performed by EQECAT, Inc. The Company indicates that the study found the expected annual damage from all hurricanes is $8.3 million, with $6.8 million of that representing expense chargeable to the reserve. At page 12 of his testimony, Mr. Harris states that the current accrual of $3.5 million is too small to pay for most storm damage. As set forth in the direct testimony of Gulf witness Erickson, page 6, the Company is requesting to increase the accrual to $9.0 million per year to cover annual losses and to reach a reserve balance goal, stated in Gulf's last rate case, of $48.0 to $55.0 million.

Q. DO YOU AGREE THAT THE ANNUAL RESERVE ACCRUAL SHOULD BE INCREASED FROM $3.5 TO $9.0 MILLION?

A. No. In fact, I recommend that the annual storm damage reserve accrual should be eliminated altogether, for several reasons. These reasons include:

1. The storm damage reserve is not intended to cover super storms. The Commission provides recovery of these larger, unusual storms through allowed surcharges.

2. Gulf is currently engaged in storm hardening activities that are intended to mitigate storm losses.

3. An accrual for infrequently occurring major storms creates intergenerational inequities whereby current ratepayers fund recovery costs for future ratepayers' losses.

4. Large storm accruals embedded in base rates create an additional profit center for the Company to the extent load growth results in higher amounts being collected in rates than the fixed amounts being credited to the reserve account each year.

5. The Commission in recent decisions has authorized the elimination of storm damage accruals for Duke Energy, FPL, and Tampa Electric Company, leaving Gulf Power as the only major electric utility with a storm damage accrual.

Based upon these considerations, it does not appear that the Company's requested accrual increase is warranted. To the contrary, it appears the existing storm damage reserve balance (of approximately $35.4 million) is sufficient under the present circumstances for the Commission to eliminate the annual reserve accrual at this time.

Q. PLEASE EXPLAIN WHY THE STORM DAMAGE RESERVE ACCOUNT IS NOT INTENDED TO COVER MAJOR STORM LOSSES?

A. The Company's calculated expected average annual storm expense of $6.8 million includes losses from all hurricanes over a long period of time. The Company's requested accrual level of $9 million per year is set at an amount that will recover these calculated storm levels and build the reserve account to its target levels. However, Southern Company's Form 10-K for 2012, page II-323, acknowledges that the Company would be able to recover the losses from major storms even without the reserve accrual through a streamlined surcharge process. The Commission has consistently allowed for the recovery of major storm losses through a temporary surcharge on customer bills. Moreover, it is clear from the Commission's order in Gulf's last rate case, Order No. PSC-12-0179-FOF-EI, page 29, that the storm damage reserve is not intended to cover all storms. As a consequence, the Company's objective of setting an annual accrual to accommodate all storm losses, including major storms, is not appropriate.

Further, there are sufficient funds in the reserve account at this time to accommodate several years of normal storm losses based on the Company's actual loss experience. As set forth in the Company's Response to Citizens' Interrogatory No. 161, for the period January 2006 through July 2013, Gulf experienced actual storm damage expense of $6.470 million, which comes to an average annual expense of $863,000. According to the Company's Response to Citizens' Interrogatory No. 162, Gulf's storm reserve balance at July 2013 was $32 million. Based on the actual loss rate from 2006 forward, the existing reserve account would last for another 37 years, assuming major storm losses were recovered through a surcharge. While it may not be correct to assume that future losses will reflect past losses, it is also an unrealistic assumption that the Company needs to accrue for all storm losses in the reserve account when it is clear that major storm losses will not be recovered from the reserve, but instead through a surcharge mechanism.

Q. WHY IS IT SIGNIFICANT THAT THE COMPANY IS CURRENTLY ENGAGED IN A STORM HARDENING PROGRAM TO PROTECT AGAINST STORM DAMAGE LOSSES?

A. Ratepayers are currently funding a storm hardening program that is expected to reduce storm damage losses in the future. In its current storm hardening application, filed May 13, 2013, the Company seeks to spend approximately $47 million for storm hardening costs over the 2013-2015 time period. The benefits of these expenditures are not known to the Company at this time. The Company intends to evaluate the benefits of the hardening initiative following a major storm in the future. It is generally understood that storm hardening costs will reduce damage and restoration times. However, the important point here is that the storm hardening benefits have <u>not</u> been taken into account in the Company's storm loss study. Thus, the Company cannot definitively say at this time that the current reserve balance (of approximately $35 million at year end) is not sufficient to cover normal storm activity when the storm hardening program benefits are ignored in the study intended to support the accrual.

My concern is that current ratepayers will be paying more for storm costs than may be necessary if they are asked to fund *both* the storm hardening program – that is expected to reduce future losses – and an annual storm loss accrual that has not taken into account the storm hardening program benefits. This concern is particularly important given the current economic downturn and slow economic recovery.

Q. ARE YOU CONCERNED THAT CURRENT ACCRUALS FOR FUTURE STORMS CREATE INTERGENERATIONAL INEQUITIES?

A. Yes. A fundamental ratemaking principle is that each generation of ratepayers should bear its share of the costs to provide service. This means that one generation of ratepayers should not be required to subsidize another generation; nor should one generation expect to be carried by another generation of ratepayers. This is why, for example, depreciation recoveries for ratemaking purposes are spread evenly over the life of the assets, rather than accelerated during the early years of the asset lives, as is often the case for other businesses. The reason depreciation expense is spread evenly over the life of the asset for ratemaking purposes is to match the cost of the asset with the benefit to ratepayers, while the asset is providing value over its useful life.

The same is not true of storm damage accruals. Through a storm damage accrual, ratepayers are paying now for storms that have not yet occurred, and in the case of major storms, they are paying for storms that may not occur for many years.

Incorporated into the intergenerational equity principle is the concept that *costs follow benefits*. In other words, ratepayers should bear the costs of the benefits they enjoy. A systematic accrual for major storm damage is somewhat inconsistent with the cost/benefit principle, because ratepayers may pay for years for a storm that may not occur. In contrast, a surcharge system for major storm damage repair is much more consistent with the cost/benefit principle, because ratepayers who directly receive the benefits of a rebuilt system after a major storm pay for the costs associated with those repairs.

Q. HOW CAN LARGE STORM DAMAGE ACCRUALS IN BASE RATES CREATE AN ADDITIONAL PROFIT CENTER FOR THE COMPANY?

A. When a specific accrual amount is embedded in base rates, and the utility experiences load growth on the system, the utility could over-recover the amount included in rates. For example, if $9 million is embedded in base rates for storm cost accrual and the utility experiences load growth of 3%, the utility could recover $9.135 million, assuming the growth occurs evenly over the year. The utility could collect $9.135 million in rates; however, it would only credit $9 million of that collection to the reserve account, with the additional $135,000 going to the Company's bottom line. This would occur year after year – with slightly higher amounts of profit each year, if the growth continues – until the Company's next rate case. I am not suggesting that this result is intentional. I am simply suggesting that this result is not the intended result when a specific accrual level is set in rates for the purpose of funding a reserve account. The solution to the over-accrual problem for a reserve account is to either keep the accrual at a ***minimum*** required level, or collect the accrual through the Commission-established surcharge mechanism.

Q. PLEASE DISCUSS THE ELIMINATION OF THE STORM DAMAGE RESERVE ACCRUALS IN RECENT FPL AND DUKE ENERGY CASES.

A. In 2010, the Commission eliminated FPL's storm expense accrual. In that case, the Company sought an annual accrual amount of $150 million designed to achieve a reserve balance of $650 million. In Order No. PSC-10-0153-FOF-EI, at pages 160-163, the Commission eliminated the $150 million accrual entirely and left the reserve balance at $200 million. The Commission's decision referenced the economic conditions that were current at that time and the fact that many customers were having difficulty paying their bills. The Commission also referenced provisions for the protection of the utilities that allow them to seek recovery of prudently incurred storm costs that go beyond the reserve levels. Specifically, the Commission stated:

> We are aware that when storm costs occur, customers will be called upon to pay those costs either through a reserve fund or through a surcharge. Yet we are very aware and very concerned with the current economic times. We have been made aware, through testimony, that customers have difficulty paying their bills, without our adding an additional burden that could be deferred. . . We note that there are provisions for the protection of utilities to allow them to seek recovery of prudently incurred storm costs that go beyond the reserve level. Because these mechanisms are in place to recover storm costs, we choose at this time, not to place this additional burden on ratepayers.

Similarly, the Commission eliminated the annual storm expense accrual for Progress Energy Florida, now Duke Energy, in Order No. PSC-10-0131-FOF-EI, at pages 68-71. The Commission's order referenced the fact that storm hardening impacts were not taken into consideration in the utility's storm loss study and that it is generally understood that storm hardening will reduce damage and restoration times. The Commission also directed the Company to discontinue the accruing of interest on the reserve balance and include the balance as a reduction to rate base. Finally, in Order No. PSC-13-0443-FOF-EI, the Commission approved a rate case settlement agreement whereby Tampa Electric's annual storm expense accrual will be discontinued effective November 1, 2013.

Q. WHY ARE THESE DECISIONS IMPORTANT?

A. I think that many of the factors that motivated the Commission's decision in these cases also apply to Gulf. Gulf's storm loss study does not take into account the Company's storm hardening initiatives, which will certainly decrease both storm loss and recovery time. The Company has at its disposal safeguards that will allow the Company to recover prudently incurred storm costs above the reserve balance. The current reserve balance of approximately $35 million as of the end of 2013 is adequate to cover normal storm losses, which have averaged less than $1 million per year over the past 8-year period. Losses from a major storm can be recovered through the surcharge mechanism. The economy is still in a very slow recovery and the fact is many ratepayers still have significant difficulty paying their bills.

Q. THE COMPANY JUSTIFIES ITS PROPOSED ANNUAL ACCRUAL INCREASE BASED ON THE COMMISSION'S TARGET RESERVE LEVEL OF $48 TO $55 MILLION AS STATED IN THE LAST RATE CASE. WHY DO

YOU BELIEVE THE COMMISSION SHOULD REVISIT THE RESERVE TARGET AT THIS TIME?

A. In Gulf's last rate case, the Commission noted in Order No. PSC-12-0179-FOF-EI that the existing reserve and accrual levels would be sufficient to cover the cost of most, but not all, storms. In that Order, at page 29, the Commission went on to state that, "<u>If circumstances change, it will be appropriate to revisit this decision in a future proceeding</u>." As discussed above, there are several factors and circumstances that were not addressed by the Commission when the target reserve levels were set in the last case. First and foremost, the Company's storm hardening measures place additional cost burdens on ratepayers, and the hardening measures are expected to mitigate the damages sustained in the event of a storm. Clearly, the benefits of the storm hardening measures were not part of the equation at the time of the Commission's prior order. There is a real concern that ratepayers who will be asked to bear the costs of the additional storm hardening measures should not be asked to also fund the unnecessary burdens of ongoing storm accruals that appear unnecessary in light of available surcharge mechanisms.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. I recommend that the total amount requested in rates for the storm damage accrual, $9,000,000 on a total company basis, be adjusted out of the requested revenue requirement. This adjustment is set forth below, and in **Exhibit MEG-3**, Schedule C-8. I also recommend that the Company discontinue accruing interest on the reserve balance and instead include the balance as an offset to rate base.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Adjustment for Storm Damage Accrual	C-8	$9,000	$8,861

SECTION V. CORPORATE AIRCRAFT COST ALLOCATION

Q. HAS THE COMPANY INCLUDED ANY COSTS FOR CORPORATE AIRCRAFT IN THE REVENUE REQUIREMENT?

A. Yes. In Gulf's Response to Citizens' First Interrogatory No. 43, the Company indicates that it has included $2,244,000 for Gulf's share of aircraft operation and leasing costs.

Q. DO YOU CONSIDER THESE COSTS REASONABLE AND NECESSARY FOR THE PROVISION OF UTILITY SERVICE?

A. No. With the number of commercial flights available, it is hard for the Company to show that the use of private aircraft is reasonable or necessary for the provision of utility services. Travel by private aircraft is a luxury, and if shareholders wish to provide this perquisite for Company employees, then in my view the shareholders, rather than the ratepayers, should absorb the associated costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE INCLUSION OF THESE COSTS IN THE REVENUE REQUIREMENT?

A. I recommend that the cost of corporate aircraft allocated to Gulf Power be eliminated from the revenue requirement. This adjustment reduces the total Company cost of service by $2,244,000. This adjustment is set forth below and in **Exhibit MEG-3,** Schedule C-9.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Corporate Aircraft Cost Allocation	C-9	$2,244	$2,198

SECTION VI. UNCOLLECTIBLE ACCOUNTS EXPENSE

Q. HOW MUCH UNCOLLECTIBLE EXPENSE HAS GULF POWER INCLUDED IN THE REVENUE REQUIREMENT?

A. The Company's Schedule C-11, Uncollectible Accounts, calculates the Company's Bad Debt Factor of 0.2934%, as set forth in Column (7). This factor was based on the average of the Company's actual write-offs over a four-year period from 2009 through 2012.

Q. DO YOU AGREE WITH THE COMPANY'S METHOD OF COMPUTING ITS UNCOLLECTIBLE FACTOR?

A. No. Because the Company has experienced steady improvement in its collections, I believe it is more appropriate to utilize a three-year average to accurately reflect this trend. The three-year average for years 2010, 2011 and 2012 yields an uncollectible factor of 0.2801%. The Company's 0.2934% uncollectible factor is reduced to the recommended rate of 0.2801% in Exhibit MEG-3, Schedule A-1, which computes the Citizens' Adjusted Net Operating Income Multiplier percentages.

Q. HOW IS THIS REVISED UNCOLLECTIBLE FACTOR REFLECTED IN YOUR ADJUSTMENT?

A. To accurately reflect the jurisdictional factors used by the Company for its

Uncollectible Expense, my adjustment starts with the Company's adjusted Uncollectible Expense of $3,809,000, as reflected on Gulf's Schedule C-4 Jurisdictional Separation Factors – Net Operating Income, at page 4 of 6, line 24. Applying the three-year uncollectible factor reduces the Company's 2014 test year write-offs from $3,809,000 to $3,663,000, a reduction of $146,000. This adjustment is reflected below and in **Exhibit MEG-3**, Schedule C-10.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Uncollectible Accounts Adjustment	C-10	$146	$144

SECTION VII. PROJECTED REVENUE ANNUALIZATION

Q. WHAT IS THE ISSUE REGARDING THE COMPANY'S REVENUEPROJECTIONS?

A. Gulf witness Rhonda J. Alexander addresses the Company's forecast methodology for projecting the Company's retail energy sales. On page 5 of her testimony, Ms. Alexander states that the Company's revenue forecast in the last rate case projected substantial increases in energy sales that turned out to be overly optimistic. It appears that in this proceeding the Company has taken a more cautious approach. At page 8, Ms. Alexander states that, "given the prolonged recessionary effects and the continued uncertainty surrounding economic recovery nationally and regionally, the risk associated with economic uncertainty is higher now than has historically been the case."

Q. WHAT IS YOUR CONCERN REGARDING THE COMPANY'S ESTIMATED REVENUE GROWTH PROJECTION IN THIS CASE?

A. I relied on Gulf's Schedule B 2013A Residential Energy Sales Forecast and Gulf's Schedule E-13C in reviewing the Company's methodology for forecasting its test year residential energy sales. I ascertained that, in its effort to avoid overstating expected revenues, the Company has failed to include an appropriate test year end annualization in its forecast, which causes the Company's projected revenues to be understated.

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU RECOMMEND.

A. To address this issue, I applied a standard test year end annualization for the 2014 test year based upon the Company's projected customer count level for December 2014. Applying this annualization resulted in an increase of $1,242,838 in the Company's projected energy sales related to the residential class.

Q. DID THE COMPANY USE SIMILAR ANNUALIZED YEAR-END PROJECTIONS FOR SOME OF ITS EXPENSE ADJUSTMENTS?

A. Yes. The Company's payroll expense, employee medical expense and other expense adjustments are made on the premise that the same year-end number of employees are on the payroll throughout all 12 months of the forecasted test year. For the sake of consistency, the Company should also apply a test year end annualization to its projected revenues as it does for its projected expenses.

Q. HAVE YOU PROPOSED SIMILAR ADJUSTMENTS TO OTHER RATE CLASSES IN THIS PROCEEDING?

A. No. I have only recommended this adjustment for the residential class because the adjustments to the other classes using this approach are immaterial in amount.

Q. WHAT IS THE ADJUSTMENT TO THE COMPANY'S REVENUE ESTIMATE?

A .The adjustment is an increase of $1,242,838 in the Company's projected energy sales related to the residential class, and is set forth below and in **Exhibit MEG-3**, Schedule C-11.

Description of OPC Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Projected Revenue Annualization	C-11	$1,244	$1,244

SECTION VIII. TRANSMISSION EXPENSE ADJUSTMENT

Q. WHAT IS OPC RECOMMENDING WITH RESPECT TO TRANSMISSION COSTS?

A. OPC's recommendations with respect to transmission costs are set forth in the testimony of OPC witness Mr. Scott Norwood. Mr. Norwood first addresses Gulf's primary proposal to recover transmission upgrade costs through the Environmental Cost Recovery Clause ("ECRC"). In his testimony, Mr. Norwood concludes that Gulf's proposed transmission upgrade costs are not required for environmental compliance and have not been demonstrated to be prudent; therefore, these costs do not meet the Commission's criteria for recovery through the ECRC.

Mr. Norwood also addresses Gulf Power's alternative request for recovery of the transmission upgrade costs, should these costs not be approved for ECRC recovery.

Gulf's alternative request is to recover $637,000 in base rates now for projected transmission upgrade costs for the 2014 test year and then to receive a step increase in base rates of $16.392 million, effective on July 1, 2015, to recover the projected costs of transmission upgrades for Plant Crist and Plant Smith for the 12-month period ending June 30, 2016. In his testimony, Mr. Norwood concludes that Gulf's alternative recovery proposal is not reasonable. He explains that Gulf has not demonstrated that its proposed transmission upgrades are prudent, due to the Company's failure to provide support for its Must-Run operating assumptions and its failure to consider Plant Smith retirement alternatives. Moreover, he explains that there is significant uncertainty regarding the forecasted step increase for these upgrades due to the fact that the forecasts extend approximately 18 months beyond the end of the 2014 test year. For these reasons, Mr. Norwood recommends that Gulf's alternative request to recover proposed transmission upgrade costs associated with its proposed environmental "compliance" plan for Plant Crist and Plant Smith also be denied.

Q. WHAT HAVE YOU INCLUDED IN YOUR REVENUE REQUIREMENT CALCULATIONS FOR TRANSMISSION EXPENSE?

A. I have included an adjustment of $637,000 to operating expense to reflect the transmission expense recommendations addressed in the direct testimony of OPC witness Norwood. This adjustment is set forth below and in **Exhibit MEG-3**, Schedule C-12.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Annualized Revenue Adjustment	C-12	$637	$618

SECTION IX. DEPRECIATION EXPENSE ADJUSTMENT

Q. WHAT HAVE YOU INCLUDED IN YOUR REVENUE REQUIREMENT CALCULATIONS FOR DEPRECIATION EXPENSE?

A. I have included a depreciation expense adjustment of $14,133,000 to reflect the depreciation expense recommendations addressed in the direct testimony of OPC witness Mr. Jacob Pous. His total depreciation expense adjustment of $19,986,000 includes an adjustment of $14,133,000 to base rates, and an adjustment of $5,853,000 to the environmental cost recovery clause. This adjustment is set forth below and in **Exhibit MEG-3**, Schedule C-13.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Depreciation Expense Adjustment	C-13	$14,133	$13,878

The amount of this adjustment, however, is subject to possible revision based on Mr. Pous' review of the results of pending discovery requests. If Mr. Pous makes any additional modification to his recommendations based on his review of these pending responses, I will make a corresponding modification to OPC's Revenue Requirement Exhibit.

SECTION X. RATE BASE ADJUSTMENTS

A. Rate Base Adjustment For Short-Term Incentives

Q. PLEASE DESCRIBE YOUR RATE BASE ADJUSTMENTS FOR DISALLOWED SHORT-TERM INCENTIVE COSTS.

A. With respect to short-term incentive costs, I recommended that short-term incentive costs directly related to financial performance be disallowed. I also recommended that 50% of the short-term plan related to customer satisfaction be disallowed. To the extent that these amounts are excluded from operating expense, a corresponding adjustment should be made to remove the associated portions of these incentive plans included in rate base. The corresponding adjustment needed to remove the associated capitalized costs from rate base would be $2,420,000 for both adjustments; $2,126,000 for the amount removed for financial-based incentives and $294,000 for the amount removed for customer satisfaction. These adjustments are shown below and can be seen at **Exhibit MEG-3**, Schedule B-3.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Rate Base Adjustment for Short-Term Incentives	B-3	$2,420	$2,375

B. Rate Base Adjustment For Storm Damage Reserve

Q. PLEASE DESCRIBE YOUR RATE BASE ADJUSTMENT FOR STORM DAMAGE RESERVE COSTS.

A. In Section IV of my testimony, I recommended that the Company discontinue the accruing of interest on the storm reserve balance and instead include the balance as an offset to rate base. This is the treatment ordered by the Commission for Progress

Energy Florida (now Duke Energy). In Order No. PSC-10-0131-FOF-EI, at pages 68-71, the Commission not only ordered the Company to discontinue the storm reserve accrual, but it also directed the Company to discontinue accruing interest on the reserve balance and include the balance as a reduction to rate base. I believe that this is the appropriate treatment for ratemaking purposes. Currently, the reserve balance accrues interest of less than 1%. As a reduction to rate base, the reserve balance would earn a return of more than 8%. This is the real value of capital to the Company and, thus, it is the value that ratepayers should receive for their capital.

At the end of 2013, the reserve balance is projected to be $35,372,000, according to Gulf's Response to Citizens' Interrogatory No. 162. This is the amount that should be included as a reduction to rate base, and is set forth below and in **Exhibit MEG-3**, Schedule B-4.

Description of OPC's Adjustment	Exhibit MEG-3 Ref.	Total Company ($000)	Florida Jurisdictional ($000)
Rate Base Adjustment for Storm Damage Reserve	B-4	$35,372	$34,824

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Direct Testimony of Mark E. Garrett has been furnished by U.S. Mail and/or hand delivery to the following parties on this 16th day of October, 2013, to the following:

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WORK HISTORY:

CONSULTING PRACTICE (1996 - Present) Participate as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies making recommendations related to cost-based rates. Review management decisions of regulated utility companies for reasonableness from a ratemaking perspective, especially in proceedings to review the reasonableness of prices paid for natural gas supplies and transportation, coal supplies and transportation, purchased power and renewable energy projects. Participate in gas gathering, gas transportation, gas contract and royalty valuation disputes to determine pricing and damage calculations and to make recommendations concerning the reasonableness of charges to royalty and working interest owners and other interested parties. Participate in regulatory proceedings to restructure the electric and natural gas utility industries. Also participate as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION – Aide to Commissioner Bob Anthony (1995)

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller for Real Estate Development Company with $300 million in assets (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPA's - Auditor (1986 - 1987) Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Entergy Texas Inc., 2013 (PUC Docket No. 49791) –** Participating as an expert witness on behalf of the Cities[1] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

2. **NV Energy, Inc., 2013 (Docket No. 13-07021**) – Participating as an expert witness in the MidAmerican/NVE merger and acquisition docket on behalf of the Southern Nevada Hotel Group[2] before the Public Utility Commission of Nevada to provide testimony regarding the merger in general and the requested acquisition premium in particular.

3. **Entergy Arkansas, 2013 (Docket No. 13-028-U) –** Participating as an expert witness on behalf of the Hospital and Higher Education Consumers ("HHEC") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

4. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002) –** Participating as an expert witness on behalf of the Northern Nevada Utility Customers before the Nevada PUC in SPPC's general rate case proceeding to provide testimony on various cost of service and revenue requirement issues.

5. **Sierra Pacific Power Company, 2013 (Docket No. 13-06004) –** Participating as an expert witness on behalf of the Northern Nevada Utility Customers before the Nevada PUC in SPPC's application for new depreciation rates to provide testimony on the Company's excess depreciation reserve to address how the excess reserve should be treated for ratemaking purposes.

6. **Gulf Power Company, 2013 (Docket No. 130140-EI) –** Participating as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power's general rate case proceeding to provide testimony on various revenue requirement issues.

7. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200054) –** Participating as an expert witness on behalf of the Oklahoma Industrial Energy Consumers ("OIEC")[3] before the Oklahoma Corporation Commission ("OCC") to provide testimony in PSO's application seeking Commission approval of its settlement agreement with EPA.

8. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

9. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

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1 Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange
2 The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.
3 OIEC is an association of approximately 25 large industrial manufacturing facilities in Oklahoma.

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10. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University's general rate case with the Corix Group, which provides utility services to the University.

11. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079) –** Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility's request to earn additional compensation on a 510MW purchased power agreement with Exelon

12. **Centerpoint Energy Texas Gas, 2012 (Docket No.** GUD 10182) – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.

13. **Entergy Texas Inc., 2012 (PUC Docket No. 39896) –** Participating as an expert witness on behalf of the Cities[4] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

14. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participating as an expert witness on behalf of the OIEC before the OCC in ONG's Performance Based Rate ("PBR") application seeking Commission approval of a requested rate increase based upon formula results for 2011.

15. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.

16. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.

17. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

18. **Nevada Power Company, 2011, (Docket No. 11-04010) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to sponsored written and oral testimony to address proposed changes to the Company's customer deposit rules.

19. **Nevada Power Company, 2011, (Docket No. 11-06006) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

20. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking rider recovery of third party SPP transmission costs and fees.

4 Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange

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21. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087) –** Participating as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

22. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E's application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.

23. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retire medical expense in the Company's pension tracker mechanism.

24. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO's application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.

25. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E) –** Participated as an expert witness on behalf of the Colorado Retail Council ("CRC") before the Colorado Public Utilities Commission providing written and live testimony to address PSCo's proposed Environmental Tariff.

26. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers ("NWIEC")[5] before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

27. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.

28. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts ("AIM") to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound

29. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

30. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

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5 NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

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31. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

32. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participating as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E's 220MW self-build wind project.

33. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.

34. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company's proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company's proposed wind subscription tariff.

35. **Nevada Power Company, 2010 (Docket No. 10-02009) –** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to provide testimony in NPC's Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.

36. **Entergy Texas Inc., 2010 (PUC Docket No. 37744) –** Participating as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

37. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

38. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.

39. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

40. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

41. **Nevada Power Company, 2009, (Docket No. 08-12002) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

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42. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

43. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348) –** Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG's application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility's proposed PBR.

44. **Rocky Mountain Power, 2009 (Docket No. 08-035-38) –** Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

45. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

46. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.

47. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150)** – Participated as an expert witness on behalf of the OIEC before the OCC to address PSO's calculation of its Fuel Clause Adjustment for 2008.

48. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

49. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334) –** Participated as an expert witness on behalf of the Cities in EGSI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

50. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.

51. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447) –** Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO_2 allowances.

52. **Rocky Mountain Power, 2008 (Docket No. 07-035-93) –** Participating as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

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53. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

54. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO_2 allowances.

55. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application seeking pre-approval to construct the Red Rock coal plant to address the Company's proposed rider recovery mechanism.

56. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335) –** Participated as an expert witness on behalf of the OIEC before the OCC in ONG's application proposing alternative cost recovery for the Company's ongoing capital expenditures through the proposed Capital Investment Mechanism Rider ("CIM Rider"). Sponsored testimony to address ONG's proposal.

57. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company's use of debt equivalency in the competitive bidding process for new resources.

58. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

59. **Nevada Power Company, 2007, (Docket No. 07-01022) -** Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

60. **Nevada Power Company, 2006, (Docket No. 06-11022) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

61. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.

62. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676) –** Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities ("ATM"). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.

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63. **Nevada Power Company, 2006 (Docket No. 06-06007) –** Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

64. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516) -** Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.

65. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041) –** Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO_2 allowance proceeds.

66. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177) –** Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

67. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140) –** Participated as an expert witness on behalf of the OIEC in OG&E's 2003 an 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, it transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

68. **Nevada Power Company, 2006, (Docket No. 06-01016) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

69. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151) –** Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

70. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610) –** Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.

71. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participating as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.

72. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754) –** Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

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73. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564) -** Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

74. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

75. **Nevada Power Company, 2003, (Docket No. 03-10001) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

76. **Nevada Power Company, 2003, (Docket No. 03-11019) -** Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

77. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076) –** Participating as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

78. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226) –** Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.

79. **Nevada Power Company, 2003 (Docket No. 02-5003-5007) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.

80. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.

81. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306) -** Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.

82. **Nevada Power Company, 2003 (Docket No. 03-11019) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.

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83. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.

84. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455) –** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

85. **Nevada Power Company, 2002 (Docket No. 02-11021) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.

86. **Nevada Power Company, 2002 (Docket No. 01-11029) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's $928 million deferred energy balances.

87. **Nevada Power Company, 2002 (Docket No. 01-10001) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

88. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L) -** Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.

89. **Southern Union Gas Company, 2001 -** Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.

90. **Nevada Power Company, 2001 -** Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.

91. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54) -** Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.

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92. **Klatt v. Hunt et al., 2000 (ND) -** Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.

93. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020) -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

94. **Oklahoma Gas and Electric Co., 1999 -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

95. **Nevada Power Company, 1999 (Docket No. 99-7035) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

96. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.

97. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.

98. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023) -** Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.

99. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177) -** Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.

100. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214) -** Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.

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101. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106) -** Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.

102. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116) -** Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.

103. **Oklahoma Corporation Commission, 1996 -** Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

104. **Tenkiller Water Company, 1996 -** Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.

105. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134) -** Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

106. **Enogex, Inc., 1995 (FERC 95-10-000) -** Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

107. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477) -** Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.

108. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.

109. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.

110. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190) -** Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.

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111. Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055) - Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

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GARRETT GROUP
INCENTIVE COMPENSATION SURVEY
Of the 24 WESTERN STATES
2007, 2009, 2011

States that follow the Financial-Performance rule

Arizona The commission deals with incentive compensation plans on a case by case basis. It first compares overall compensation to the state norm, then asks if the costs are prudent and reasonable. The commission leans toward disallowing programs which benefit only the shareholder even if total compensation is comparable to the state norm. Staff's position is that unless a plan is tied to performance issues it is unnecessary for the provision of service and that shareholders should pay for plans tied to financial measures. In practice, the costs of annual incentive plans are often shared 50/50 between ratepayers and shareholders.[1]

Arkansas Excludes 100% of the long-term, equity-based plans.[2] Short-term incentive plans are evaluated to determine if they are based on financial or operational measures. Operational-based plans are allowed. 50% of plans containing financial measures are disallowed. Any plans based solely on the discretion of the company are seen as having no direct benefit to ratepayers and are disallowed 100%. Settlements in recent cases have upheld this treatment.[3]

California Incentive funding is an issue that is typically litigated. In CPUC Decision 00-02-046, the commission established that utilities could recover 50% of the regular employee's incentive compensation costs in rates. In California's latest litigated rate case, the commission decided that Edison's non-executive plans and 50% of the short-term executive plans would be funded in rates and that 100% of the executive long-term stock plans would be disallowed.[4]

[1] See *e.g.*, APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

[2] In this summary of the incentive compensation survey, the treatment of executive incentives in each state is underlined, and will be discussed in the following section of the testimony.

[3] Entergy Arkansas, 06-101-U, Order No. 10.

[4] Southern California Edison (Application No. 07-11-011; Decision No. 09-03-025).

Colorado Regular employee programs are judged based on ratepayer verses stockholder benefit ratio. Plans with metrics for goals benefiting ratepayers but dependent on an earnings-per-share trigger are considered to benefit shareholders and opposed by staff. Staff's approach is set forth most recently, in 10AL-963G by staff witness Kahl. The settlement in that case removed the dollar amount opposed by Kahl. All executive incentives are excluded from rates and typically no longer sought in company filings.

Hawaii Hawaii does not allow incentive compensation to be included in rates. In Docket No. 6531 the commission agreed that bonus awards tied to company income and earnings benefit stockholders, not ratepayers. The commission further states, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service."[5]

Idaho The commission's policy for evaluating incentive compensation plans involves determining who benefits, the customer or the company. This treatment has been refined in the recent Idaho Power rate case for plans which benefit the customer but require a financial trigger to be paid. For these plans the commission reduced the percentage allowed in rates. The commission also now does not include any executive compensation in rates.[6]

Kansas Plans based solely on financial goals are not allowed. For executive incentive programs, the Commission also disallows 100% of plans based on financial measures and 50% for plans using a balance of financial and operational measures. The Commission has allowed in rates non-executive annual incentive programs that have no focus on profitability or earning.[7]

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[5] Hawaii's policy is set forth in Docket No. 6531 in the October 17, 1991 Order No. 11317. Prior Dockets in which the commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114.

[6] The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness Leckie, and in the final order for IPC General Rate Case IPC-E-08-10. For earlier examples of the basic policy, see Idaho Power Company Rate Case IPC-E-05-28, Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28, Order No. 30035, p. 4/10.

[7] In the litigated 2010 KCP&L rate case (10-KCPE-415-RTS) the Commission also stated that relying on peer group statistics "can result in a continuing upward spiral [instead] the Commission must examine the elements of incentive packages, and the behavior they incent." The Commission held that a focus on profitability or earning might incent employee behavior "detrimental to customers."

Louisiana Traditionally incentive compensation for upper level management and officers is excluded, while costs for lower level managers and employees are allowed. The criteria used to evaluate plan design consider whether the goals of each plan directly benefit ratepayers or shareholders. Stock based compensation plans at all levels are excluded.

Minnesota Minnesota distinguishes between incentive plans tied to financial triggers (such as a threshold ROE), and plans tied to criteria benefitting the ratepayer. Plans based on goals that benefit ratepayers are allowed in rates, but their costs are capped at 25% of base salaries.[8] The portions of these plans that are allowed into rates are tracked and must be returned to ratepayers if they are not paid to employees. Executive plans are largely not allowed.[9]

Missouri Missouri's treatment disallows incentives tied to goals benefitting primarily the stockholders (*e.g.*, tied to earnings per share) while allowing plans with customer-specific goals (*e.g.*, safety). Plans must also be reasonable. The Commission also allows only the amounts actually paid, not those accrued. The same criteria are used for executive plans and few are allowed.[10]

Nevada The commission excludes 100% of the long-term plans and all short-term plan costs directly related to financial performance.[11]

New Mexico The commission does not favor incentive compensation plans that are tied to financial goals and tends to allow in rates those based on operational goals. This standard is applied to all levels of utility employees and tends to eliminate the greater portion of executive plans.[12]

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[8] This general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

[9] Minnesota's general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively. See also Minnesota Power General Rate Case E002/GR/05/1428.

[10] See *e.g.*, in the latest Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The commission also removed incentive payments tied to lobbying and charitable activity. In the most recent case processed, the Ameren UE rate case, the company did not seek even short-term incentive compensation tied to earnings, providing further indication that staff's practice of disallowing financial performance based incentives is accepted by the companies. All incentive compensation adjustments were made not only to expense charges, but to construction charges as well. *See also* recent Kansas City Power and Light and Empire Electric District orders on the commission's website.

[11] See *e.g.*, PUCN's final order in Docket 11-06006.

[12] See Docket 07-00077-UT.

N. Dakota Historically, North Dakota has followed the general policy that the portion of incentive compensation that relates to shareholder earnings is disallowed and the rest is included. However, in one recent case, the commission chose to determine if overall compensation was reasonable as compared to the market.[13] Executive incentive compensation is not allowed in rates, and is typically not sought by the company.

Oklahoma The commission excludes incentive payments tied to financial performance. From a practical perspective this means that all executive stock plans are excluded and some portion of the annual cash plan for all employees. Since the commission has not been able to determine in recent cases the precise portion of the annual plans tied to financial measures, the commission has excluded 50% of the annual plans. 100% of the executive stock plans are excluded.[14]

Oregon The commission's general policy is to evaluate plans based on whether they benefit the customers or the company. Customer-based plans involving reliability, response speed, etc. are called "merit" (operational) plans. Company-based plans which track increases to the bottom line, ROE, etc. are called "performance" (financial) plans. 50% of the cost of merit plans is disallowed and 75% of the performance plans is disallowed. 100% of officer bonuses are disallowed.[15]

S. Dakota The commission's general policy is to disallow the portion of incentive plans that are based on the company's financial performance.[16] Current treatment also includes disallowing both executive and non-executive management incentive compensation. There are no incentive compensation plans for union employees. Several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates.

[13] Other than Xcel, the utilities in North Dakota (Otter Tail and MDU) are highly diversified now (with mostly unregulated operations, *e.g*. MDU 90%). This allows utility executives to draw on the unregulated components for their compensation.

[14] See *e.g.*, AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610.

[15] A recent order reflecting this policy can be found in Docket UE 197, Order No. 09-020.

[16] In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the *Staff Memorandum* states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation."

Texas The general rule is that incentive payments designed to improve the financial performance of the utility are excluded. For example, in PUC Docket No. 28840,[17] the commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments in the amount of $4.2 million. This was the portion of the utility's incentive payments that were based on financial performance measures.[18] Long-term executive incentive pay is routinely disallowed.[19]

Utah The commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. Equity-based incentive compensation is excluded from rates.[20]

Washington Incentive plans are evaluated on a case by case basis. Incentives tied to operational efficiency or other measures which benefit ratepayers are allowed in rates and incentives based on return on earnings or other measures that benefit the shareholders are disallowed.[21]

Wyoming Employee incentive compensation plans are evaluated on a case by case basis, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. Executive incentive compensation plans are all excluded from rates.

States were Incentive Compensation has not been and Issue

Alaska Incentive compensation is not an issue in rate cases in Alaska. There is no relevant regulation or policy.

Iowa Incentive compensation is not typically an issue because few rate cases are litigated in this jurisdiction. Mid-American has an incentive compensation plan but hasn't filed a rate case in many years. For the state's other utilities, it has been a long time since they have filed a rate case or had a rate increase. The standing treatment is to consider incentive compensation plans on a case-by-case basis and to evaluate whether they are reasonably and prudently incurred. Both of the investor owned utilities in Iowa are under rate freezes until 2013 and 2014.

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[17] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840; SOAH Docket No. 473-04-1033, Final Order (August 15, 2005).
[18] See ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.
[19] See Final Order in Docket No. 39896 where even rate case costs associated with asking for long-term financial-based incentives was disallowed.
[20] The recent final order in Docket 09-035-23 follows this general policy as does the order in Docket 07-35-93. *See also* Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12; US West Communications Rate Case Docket 95-049-05.
[21] See the Order in Pacific Power and Light Docket 061546.

Montana Montana has no specific treatment directive and considers the issue on a case by case basis. In a recent NorthWestern Energy rate case, as part of a stipulation agreement, the company took a portion of its incentive compensation out of rates, but reserved the right to propose that it be included in a later filing.

Before the

Florida Public Service Commission

Docket Numbers: 130140-EI, 130151-EI, 130092-EI

GULF POWER COMPANY

REVENUE REQUIREMENT EXHIBIT

OF

CITIZENS OF THE STATE OF FLORIDA

DOCKET NOS. 130140-EI, 130151-EI, 130092-EI

October 16, 2013

Gulf Power Company
Index to Revenue Requirement Exhibits
Projected Test Year Ended December 31, 2014

Gulf Power Company
Jurisdictional Revenue Requirement
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Company's Jurisdictional Proposed Rate Increase	(4) OPC Jurisdictional Adjustments	(5) Ref.	(6) OPC Jurisdictional Proposed Rate Increase
1	Jurisdictional Adjusted Rate Base	$ 1,883,901	$ (37,199)	B-1	$ 1,846,702
2	Required Rate of Return	6.4700%	-0.9500%	D-1	5.520%
3	Jurisdictional Income Requirement (Line 1 x Line 2)	$ 121,888	$ (19,950)		$ 101,938
4	Jurisdictional Adjusted Net Operating Income	76,359	26,806	C-1	103,165
5	Income Deficiency (Sufficiency) (Line 3 - Line 4)	$ 45,529	$ (46,756)		$ (1,227)
6	Earned Rate of Return (Line 4 / Line 1)	4.05%			5.59%
7	Net Operating Income Multiplier	1.633971	0.000211	A-1	1.633760
8	**Base Rate Revenue Increase (Decrease)**	**$ 74,393**	**$ (76,398)**		**$ (2,005)**

Gulf Power Company
Net Operating Income Multiplier
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Company Percentage	(5) OPC Percentage
1	Revenue Requirement		100%	100%
2	Regulatory Assessment Rate		0.0720%	0.0720%
3	Uncollectible Expense Factor	C-4	0.2934%	0.2801%
4	Net Before Income Taxes		99.635%	99.648%
5	State Income Tax Rate (Effective)		5.500%	5.500%
6	State Income Tax		5.4799%	5.4806%
7	Net Before Federal Income Taxes		94.155%	94.167%
8	Federal Income Tax Rate (Effective)		35.000%	35.000%
9	Federal Income Tax		32.9543%	32.9585%
10	Revenue Expansion Factor		61.2007%	61.2085%
11	Net Operating Income Multiplier		1.633968	1.633760
			To Sch A	To Sch A

Gulf Power Company
OPC Adjusted Rate Base
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Company's Jurisdictional Rate Base	(4) OPC Jurisdictional Rate Base Adjustments	(5) OPC Jurisdictional Adjusted Rate Base
1	**Plant In Service:**			
2	Plant in Service	$ 2,944,168	$ (2,375)	$ 2,941,793
3	Less: Accumulated Depreciation	(1,243,319)		(1,243,319)
4	Net Plant	$ 1,700,849	$ (2,375)	$ 1,698,474
5	**Other Rate Base Investment:**			
6	Plant Held for Future Use	5,276	-	5,276
7	Construction Work In Progress	26,656	-	26,656
		-		
8	Working Capital Allowance	151,120	(34,824)	116,296
9	**Total Rate Base**	$ 1,883,901	$ (37,199)	$ 1,846,702

Gulf Power Company
OPC Rate Base Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Witness	(4) Ref No.	(5) Total Adjustments to Rate Base	(6) Jurisdictional Allocation Factor	(7) OPC Adjusted Rate Base
1	**Plant in Service Adjustments**					
2	To Remove Incentive Comp from Rate Base	Garrett	B-3	$ (2,420)	0.9814230	$ (2,375)
3	Subtotal			$ (2,420)		$ (2,375)
4	**Working Capital Adjustments**					
5	To Reduce Working Capital	Garrett	B-4	$ (35,372)	0.9845096	$ (34,824)
6	Subtotal			$ (35,372)		$ (34,824)
7	Total			$ (37,792)		$ (37,199)

Gulf Power Company
Rate Base Adjustment for Short Term Incentives
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Portion Capitalized	(5) Rate Base
7	**Performance Pay Program**	OPC ROG 80		
8	**Capital Items**			
9	Direct			$ 3,261
10	Allocated			828
11	Excluded by GPC			-
12	Subtotal			$ 4,089
13	Financial Portion of Perfomance Pay Program		52.0%	$ (2,126)
14	One Half of Customer Satisfaction Incentives		7.2%	(294)
15	Adjustment to Capitalized Incentives			$ (2,420)

Gulf Power Company
Rate Base Adjustment for Storm Damage Reserve
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Storm Damage Reserve at 12/31/2013	OPC ROG 162	$ 35,372
2	Adjustment to Include the Storm Damage Reserve in Working Capital		**$ (35,372)**

Gulf Power Company
Adjusted Operating Income Statement
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Company Jurisdictional Net Operating Statement	(5) OPC Jurisdictional Adjustments	(6) OPC Jurisdictional Adjusted Income Statement
1	**Operating Revenues:**				
2	Sales of Electricity		$ 505,620	$ 1,243	506,863
3	Other Operating Revenues		23,031	-	23,031
4	Total Operating Revenues		$ 528,651	$ 1,243	$ 529,894
5	**Operating Expenses:**				
6	Operation & Maintenance		290,199	$ (28,135)	262,064
7	Depreciation & Amortization		104,505	(13,878)	90,627
8	Amortization of ITC		(878)	-	(878)
9	Taxes Other Than Income		31,917	(814)	31,103
10	Income Taxes Federal & State		12,985	17,264	30,249
11	Net Federal Deferred Income Tax		7,959	-	7,959
12	Net State Deferred Income Tax		5,605	-	5,605
			-		-
13	**Total Operating Expenses**		$ 452,292	$ (25,563)	$ 426,729
14	**Operating Income**		$ 76,359	$ 26,806	$ 103,165

Gulf Power Company
Net Operating Income Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Witness	(4) Ref. No.	(5) Total Company Adjustment to Net Operating Income	(6) Jurisdictional Allocation Factor	(7) Jurisdictional Adjustment to Net Operating Income
1	**Operating Revenues Adjustments**					
2	To Adjust Revenues	Garrett	C- 11	1,243	1.0000000	$ 1,243
3	**Operations & Maintenance Expense**					
4	To Adjust Short Term Incentive Expense	Garrett	C-3	(8,579)	0.9806803	(8,413)
5	To Adjust Long Term Incentive Expense	Garrett	C-3	(3,160)	0.9792787	(3,095)
6	To Adjust SERP Expense	Garrett	C- 4	(2,220)	0.9792787	(2,174)
7	To Adjust Payroll expense	Garrett	C- 5	(2,248)	0.9806803	(2,205)
8	To Adjust Medical Expense	Garrett	C-6	(387)	0.9806803	(380)
9	To Adjust D&O Expense	Garrett	C- 7	(48)	0.9792787	(47)
10	To Adjust Storm Damages Expense	Garrett	C- 8	(9,000)	0.9845096	(8,861)
11	To Adjust Corporate Aircraft Expense	Garrett	C- 9	(2,244)	0.9792787	(2,198)
12	To Uncollectible Expense	Garrett	C-10	(146)	0.9830180	$ (144)
13	To Adjust Transmission Expenses	Norwood	C-12	(637)	0.9705818	(618)
14	Reserved			-	0.9806803	-
15	Subtotal			$ (28,669)		$ (28,135)
16	**Depreciation & Amortization**					
17	Depreciation Expense	Pous	C - 13	(14,133)	0.9819407	(13,878)
18	Subtotal			$ (14,133)		$ (13,878)
19	**Taxes Other than Income**					
20	To Adjust Payroll Tax Expense	Garrett	C-3, C- 5	(828)	0.9830180	(814)
21	Subtotal			$ (828)		$ (814)
22	**Income Taxes**					
23	Parent Debt Adjustment			$ -	0.9813165	$ -
24	Impact of O&M and Other Tax Adj. on FIT		C - 14	14,691	1.0000000	$ 14,691
25	Impact of O&M and Other Tax Adj. on SIT		C - 14	2,309	1.0000000	$ 2,309
26	Interest Synchronization Adjustment		C-15	$ 264	1.0000000	$ 264
27	Total Income Federal & State Income Taxes			$ 17,264		$ 17,264
28	Total Operating Income Adjustments			$ 27,609		$ 26,806
29	NOI before Income Tax Adjustments					$ 44,070

Gulf Power Company
Short Term and Long Term Incentive Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
	Short-Term Incentive Expense Adjustment		
1	Total Short-Term Incentive Expense	OPC-ROG 80	$ 14,493
2	Financial Related Short-Term Incentives	OPC-ROG 80, (h) & (i)	-52%
3	Adjustment to Exclude Financial Related Short-Term Incentives		$ (7,536)
4	Adjustment to Exclude 50% of Customer Satisfaction Incentives	OPC-ROG 80 (k)	(1,043)
5	Total Adjustment to Short-Term Incentive Expense		$ (8,579)
6	Payroll Tax Rate		7.65%
7	Adjustment to Payroll Taxes for Short-Term Incentives		$ (656)
	Long-Term Incentive Expense Adjustment		
8	Total Long-Term Incentive Expense	OPC-ROG 81 and 82, (a), (b), and (e)	$ 3,160
9	Financial Related Portion to Exclude		-100%
10	Adjustment to Exclude Financial Related Short-Term Incentives		$ (3,160)

Gulf Power Company
Supplemental Executive Retirement Plan Adjustment
Test Year Ended 12-31-10
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Total	
1	Supplemental Executive Retirement Plan Costs	OPC-ROG-7	$	2,220
2	Expense Percentage			100.00%
3	Total Company SERP in Cost of Service		$	2,220
4	Adjustment to Remove SERP Expense		$	(2,220)

Gulf Power Company
Payroll Expense and Payroll Tax Adjustments
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4)	(5) Amount
1	Company's Payroll Expense, 2012	OPC-POD 1-1		$ 81,371
2	Manufacturing Sector Productivity 2007-2012	Productivity and Labor Costs, BLS 9/2/2013		1.7%
3	OPC Productivity Adjustment 2012 - 2013			$ (1,383)
4	Adjusted Company's Payroll Expense, 2013	OPC-POD 1-1 + Line 3	$ 83,735	
5	Manufacturing Sector Productivity 2007-2012	Productivity and Labor Costs, BLS 9/2/2013	1.7%	
6	OPC Productivity Adjustment 2013 - 2014			(1,423)
7	OPC Total Productity Adjustments	Line 3 + Line 6		$ (2,806)
8	Less Company's Hiring Lag Adjustment	OPC-POD 1, C-3 Backup		(558)
9	OPC Net Productivity Adjustment	Line 7 - Line 8		$ (2,248)
10	Payroll Tax Rate			7.65%
11	OPC Payroll Tax Adjustment	Line 9 x Line 10		$ (172)

Gulf Power Company
Employee Medical Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3)	(4) Ref.	(5) Amount
1	2012 Medical Expense		OPC-ROG 10	$ 8,728
2	Employee Increase Factor			1.0475
3	Medical Cost Increase, 7% for 2 years		TW: 2013 Employer Survey on Purchasing Value in Health Care	1.1449
4	OPC Employee Medical Cost			$ 10,467
5	Less Company Proforma Employee Medical Cost		OPC-ROG 10	10,854
6	OPC Adjustment to Employee Medical Cost			$ (387)

Gulf Power Company
Directors and Officers' Liability Insurance Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Total Director and Officer Liability Insurance	Erickson, p. 11	$ 95
2	Portion to Exclude		50%
3	Adjustment to Director and Officer Liability Insurance		$ (48)

Gulf Power Company
Storm Damage Accrual Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Recommended Storm Damage Reserve Accrual		$ -
2	Test Year Storm Damage Reserve Accrual	Erickson, p. 6	9,000
3	OPC Adjustment to Storm Damage Reserve Accrual		$ (9,000)

Gulf Power Company
Corporate Aircraft Cost Allocation Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Recommended Corporate Aircraft Cost		$ -
2	Company's Requested Corporate Aircraft Cost	OPC-ROG 43	2,244
3	OPC Adjustment to Corporate Aircraft Expenses		$ (2,244)

Gulf Power Company
Uncollectible Accounts Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Net Write-Offs	(5) Gross Revenues	(6) Uncollectible Factor
1	2010	GPC C-11	$ 3,806	$ 1,295,892	0.2937%
2	2011	GPC C-11	$ 3,384	$ 1,233,068	0.2744%
3	2012	GPC C-11	$ 3,084	$ 1,133,224	0.2721%
4	3-Year Average Uncollectible Factor				0.2801%
5	2014 Gross Revenues, Per Company				$ 1,307,803 (1)
6	OPC Recommended Uncollectible Amount				$ 3,663
7	Uncollectible Amount per Company	GPC C-4			$ 3,809
8	OPC Reduction to Uncollectible Accounts				$ (146)

(1) Inadvertently, a 2012 value was used. The amount should be $1,293,402, based on GPC C-11. The error favors the Company. However, correcting the error would have only a de minimis effect on the adjustment shown. For that reason, and due to the timing of the discovery of the error, the correction (which would impact several schedules) was not made.

Gulf Power Company
Revenue Annualization Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Revenue Amount
1	OPC Adjusted Residential Electric Revenue Based on Annualized Customers		$ 297,720
2	Gulf Power Company Adjusted Residential Electric Revenue	GPC E-13c, p 1	$ 296,477
3	Adjusted Amount		$ 1,243

Gulf Power Company
Transmission Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Adjustment to Transmission Expense	Norwood	$ (637)

Gulf Power Company
Depreciation Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	OPC Total Adjustment to Depreciation Expense		$ (19,986)
2	Less: OPC Adjustment to Depreciation Expense in Cost Recovery Clauses	Pous	(5,853)
3	OPC Adjustment to Depreciation Expense in Base Rates		$ (14,133)

Gulf Power Company
Current Income Tax Expense Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Jurisdictional Operating Income Adj. before Income Taxes		$ 44,070
2	Composite Income Tax Rate		38.575%
3	Adjustment to Income Tax Expense		$ 17,000
4	Federal		$ 14,691
5	State		2,309
6	Total Federal & State		$ 17,000

Gulf Power Company
Interest Synchronization Adjustment
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description	(3) Ref.	(4) Amount
1	Adjusted Jurisdictional Rate Base	B-1	$ 1,846,702
2	Weighted Cost of Debt	D-1	1.84%
3	Interest Deduction for Income Taxes		$ 33,979
4	Interest Deduction for Income Per Company		34,664
5	Increase in Deductible Interest		$ (685)
6	Consolidated Income Tax Rate		38.575%
7	Reduction (Increase) to Income Tax Expense		**$ (264)**
8	Long Term Debt	D-1	1.80%
9	Short Term Debt	D-1	0.01%
10	Customer Deposits	D-1	0.03%
11	Weighted Cost of Debt		1.84%
12	GPC Total Company Jurisdictional Rate Base		**$ 1,883,901**

Gulf Power Company
Capital Structure
Projected Test Year Ended December 31, 2014
($000)

(1) Line No.	(2) Description		(3) Capitalization Jurisdiction Amount	(4) Ratio	(5) Cost of Capital	(6) Weighted Cost of Capital
1	**GPC Requested Capital Structure:**					
2	Long Term Debt	$	685,025	36.36%	4.96%	1.80%
3	Short Term Debt		27,615	1.47%	0.82%	0.01%
4	Preferred Stock		79,085	4.20%	6.00%	0.25%
5	Common Stock		715,221	37.96%	11.50%	4.37%
6	Customer Deposits		20,943	1.11%	2.30%	0.03%
7	Deferred Income Tax		379,918	20.17%	0.00%	0.00%
8	FASB 109 Deferred Taxes		(25,718)	-1.37%	0.00%	0.00%
9	Investment Credit		1,812	0.10%	8.18%	0.01%
10	TOTAL	**$**	**1,883,901**	**100.00%**		**6.47%**
11	**OPC Adjusted Capital Structure:**					
12	Long Term Debt	$	685,025	36.36%	4.96%	1.80%
13	Short Term Debt		27,615	1.47%	0.82%	0.01%
14	Preferred Stock		79,085	4.20%	6.00%	0.25%
15	Common Stock		715,221	37.96%	**9.00%**	3.42%
16	Customer Deposits		20,943	1.11%	2.30%	0.03%
17	Deferred Income Tax		379,918	20.17%	0.00%	0.00%
18	FASB 109 Deferred Taxes		(25,718)	-1.37%	0.00%	0.00%
19	Investment Credit		1,812	0.10%	8.18%	0.01%
20	TOTAL	**$**	**1,883,901**	**100.00%**		**5.52%**