BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Gulf Power Company.	DOCKET NO. 110138-EI ORDER NO. PSC-12-0179-FOF-EI ISSUED: April 3, 2012

The following Commissioners participated in the disposition of this matter:

RONALD A. BRISÉ, Chairman
LISA POLAK EDGAR
ART GRAHAM
EDUARDO E. BALBIS
JULIE I. BROWN

APPEARANCES:

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On behalf of Gulf Power Company (GULF).

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On behalf of the Citizens of the State of Florida (OPC).

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On behalf of Florida Industrial Power Users Group (FIPUG).

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On behalf of the Florida Public Service Commission (STAFF).

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Advisor to the Florida Public Service Commission.

FINAL ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR RATE INCREASE AND APPROVING STIPULATIONS

BY THE COMMISSION:

I. BACKGROUND

This proceeding commenced on July 8, 2011, with the filing of a petition for a permanent rate increase by Gulf Power Company (Gulf or Company). The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. Gulf serves more than 431,000 retail customers in eight counties in Northwest Florida.

In this proceeding Gulf requested an increase in its base rates and charges to generate $93,504,000 in additional gross annual revenues. This increase would allow the Company to earn an overall rate of return of 7.05 percent or an 11.70 percent return on equity (range 10.70 percent to 12.70 percent). The Company based its request on a projected test year ending December 31, 2012. Gulf also requested an interim rate increase in its base rates and charges to generate $38,549,000 in additional gross annual revenues. The Company based its interim request on a historical test year ended March 31, 2011.

Pursuant to a stipulation approved in Order No. PSC-11-0553-FOF-EI,[1] Gulf filed supplemental testimony on November 8, 2011, for an additional base rate increase of $8,104,000 for the inclusion of the Crist Units 6 and 7 turbine upgrade projects in the instant proceeding. As a result, Gulf's total requested base rate increase was revised to $101,608,000.

Pursuant to Sections 366.06 and 366.071, F.S., by Order No. PSC-11-0382-PCO-EI, issued September 12, 2011, we suspended Gulf's proposed permanent rate schedules pending further review, and authorized an interim rate increase of $38,549,000.

[1] See Order No. PSC-11-0553-FOF-EI, issued December 7, 2011, in Docket No. 110007-EI, In re: Environmental cost recovery clause.

The Office of Public Counsel (OPC), Federal Executive Agencies (FEA), Florida Retail Federation (FRF), and Florida Industrial Power Users Group (FIPUG) intervened in this proceeding (collectively "Intervenors").

Customer service hearings were held in Pensacola and Panama City on September 15, 2011. A total of 79 customers presented testimony at the two customer service hearings. A technical hearing was conducted December 12-15, 2011. At the January 10, 2012, Commission Conference, we approved the parties' Motion for Approval of Partial Settlement Agreements, effectively reducing Gulf Power's requested O & M expense by $675,000 in exchange for dropping certain issues[2] while also approving the cost of service methodology, treatment of distribution costs, and allocation of revenue increase to rate classes. At the February 27, 2012, Commission Conference, we approved an increase to operating revenues of $64,101,662 for the 2012 projected test year. We also approved a $4,021,905 January 2013 step increase to reflect the inclusion of Crist Units 6 and 7 Turbine Upgrade Projects in rate base rather than through the Environmental Cost Recovery Clause. The final revenue increase for 2012 and 2013 is shown in Schedule 1.

On March 12, 2012, we approved the remaining rates issues which had not been addressed at the February 27, 2012, Commission Conference.

We have jurisdiction over these matters pursuant to Sections 366.06 and 366.071, F.S.

II. APPROVED STIPULATIONS

We have previously approved several stipulated issues. The stipulated issues are reflected below in the body of this order, as well as in a consolidated list attached hereto as Appendix 1.

III. LEGAL ISSUE PERTAINING TO THE NORTH ESCAMBIA SITE

In this proceeding Gulf argued that pursuant to Rule 25-6.0423, Florida Administrative Code (F.A.C.), which implements Section 366.93, F.S., it is authorized to accrue a carrying charge on the cost of acquiring the Escambia Site and the cost of the associated evaluations prior to any need determination ($27,687,000). Gulf asserted that under Rule 25-6.0423(2)(e), F.A.C., a site is deemed to be selected upon the filing of a need determination petition. Gulf contended that costs incurred prior to the filing of the need petition are "site selection costs" under subsection (2)(f), while costs incurred after the filing are "pre-construction costs" under subsection (2)(g). Thus, the cost of acquiring the Escambia Site and the cost of the associated evaluations prior to any need determination should be deemed site selection costs because these costs have been incurred and Gulf has not filed a petition for a determination of need. Gulf contended because these cost are site selection costs under Rule 25-6.0423(2)(e), F.A.C., it is

[2] The subject matter removed for consideration were Issue 11 (the inclusion of capital cost of the Perdido landfill gas facility in Gulf's rate base), Issue 62 (aircraft expenses), Issue 63 (corporate leased aircraft expenses), and Issue 80 (pole inspections expenses).

entitled to deferred accounting treatment pursuant to Rule 25-6.0423(3), F.A.C. Rule 25-6.0423(3), F.A.C., states that site selection costs shall be afforded deferred accounting treatment and shall accrue a carrying charge equal to the utility's AFUDC rate until recovered in rates.

OPC, FIPUG, FRF, and FEA opposed Gulf's interpretation of Section 366.93, F.S., and Rule 25-6.0423, F.A.C. Rather, the Intervenors contended that Rule 25-6.0423, F.A.C., authorizes a utility to defer accounting treatment of nuclear site selection costs and accrue carrying charges until recovered in rates only after we award an affirmative determination of need for the unit.

As explained below, we find Gulf's interpretation of Section 366.93, F.S., and Rule 25-6.0423, F.A.C., unpersuasive. Section 366.93, F.S., and Rule 25-6.0423, F.A.C., establish a threshold criteria that Gulf must satisfy before it can calculate a deferred carrying charge for the 4,000 acre Escambia Site and the costs of the associated evaluations as nuclear site selection costs. In the instant case, Gulf has not obtained an order granting a need determination for a nuclear power plant pursuant to Section 403.519, F.S., and as required by Section 366.93, F.S. As such, we find that Section 366.93, F.S., does not support Gulf's proposal to calculate a deferred carrying charge for the 4,000 acre Escambia Site and the costs of associated evaluations as nuclear site selection costs.

Gulf Has Not Obtained a Determination of Need

Gulf witness Burroughs stated that Gulf identified the Escambia Site in north Escambia County as the only suitable site for a nuclear plant. The Escambia Site is also suitable for other generation technologies. Gulf witness Alexander explained that in 2007 Gulf began investigating the Escambia Site as a potential future power plant site. On August 26, 2008, Gulf decided to purchase the Escambia Site. Witness Alexander asserted that the Escambia Site was "investigated and purchased to preserve a nuclear option for Gulf's customers because that option has such a high potential value to Gulf's customers and the site was unique."

Gulf did not assert it was engaged in nuclear power plant permitting or licensing actions, nor did Gulf assert it was seeking a determination of need for a nuclear power plant. Gulf witness Burroughs stated that Gulf did not have any planned development in the next ten years. Witness Burroughs stressed strategic planning concerns and Gulf's desire to preserve a future nuclear power plant option as the basis for the actions taken and costs incurred. Gulf witness Alexander also stressed planning flexibility. Gulf witness Burroughs noted the following:

> For me to be able to project out, we can't do that. But we know we will have to make a decision come 2022 and we can't wait 'till then to do it. We have to be prepared in the next two, three, four years to make a decision what we're going to do.

Gulf witness Alexander stated that "I can't tell you for sure that we are going to build nuclear because there is so much uncertainty."

OPC witness Schultz stated Gulf had not filed for a determination of need. FEA witness Meyer opined that Gulf had not obtained the necessary approvals required by Section 366.93, F.S. Witness Schultz opined that Gulf's purchase of the Escambia Site was "based on nothing more than speculation that nuclear generation might be a viable option for its customers at some time in the future." FRF witness Chriss asserted that Gulf had not specified that the land would be used only for nuclear or integrated gasification combined cycle power plants. Gulf did not rebut the assertions that it had not filed for, nor obtained an order granting a determination of need for a nuclear power plant.

Threshold Requirement

The absence of Gulf obtaining a need determination pursuant to Section 403.519, F.S., is significant because Section 366.93(3), F.S., establishes when a utility may avail itself of the alternative cost recovery mechanisms established by Section 366.93, F.S. Section 366.93(3), F.S., states, "After a petition for determination of need is granted, a utility may petition the commission for cost recovery as permitted by this section and commission rules." (emphasis added)

Nevertheless, Gulf witness McMillan asserted that Gulf's Escambia Site acquisition costs and deferred nuclear site selection costs through the end of 2011 were in accordance with Section 366.93, F.S. Witness McMillan's view was that Section 366.93, F.S., was applicable to Gulf's request because the statute provided authorization to record a deferred return. He relied on the site selection cost definitions and accounting provisions in Rule 25-6.0423, F.A.C. Gulf witness Alexander further asserted that deferred carrying charges have been accrued monthly since January 2008 and will continue to be accrued until such time that these costs are included in rate base.

We find that Gulf witnesses McMillan and Alexander fail to observe the plain language of Section 366.93, F.S., which places a statutory threshold criteria that Gulf must obtain an affirmative order granting a determination of need for a nuclear power plant before it can petition to take advantage of the alternative cost recovery mechanisms. Section 366.93(3), F.S., states, "After a petition for determination of need is granted, a utility may petition the commission for cost recovery as permitted by this section and commission rules." Thus, the alternative cost recovery mechanisms established by Section 366.93 F.S., are conditional based upon our issuing a determination of need order for a nuclear power plant for Gulf.

This statutory threshold criteria is also explicitly stated in Rule 25-6.0423(4), F.A.C., regarding site selection costs:

> After the Commission has issued a final order granting a determination of need for a power plant pursuant to 403.519, F.S., a utility may file a petition for a separate proceeding, to recover prudently incurred site selection costs. This separate proceeding will be limited to only those issues necessary for the determination of prudence and alternative method for recovery of site selection costs of a power plant.

(emphasis added) Thus, Section 366.93, F.S., and Rule 25-6.0423, F.A.C., defers identification of a site as a nuclear power plant site until we have determined that a nuclear power plant is needed pursuant to Section 403.519, F.S., and a utility has petitioned to recover prudently incurred site selection costs pursuant to Rule 25-6.0423(4), F.A.C.

Gulf argued that Rule 25-6.0423(2)(f), F.A.C., specifically defines site selection costs to be "costs that are expended prior to the selection of a site." Rule 25-6.0423(2)(e), F.A.C., states "a site will be deemed to be selected upon the filing of a petition for a determination of need for a nuclear or integrated gasification combined cycle power plant pursuant to Section 403.519, F.S." Reading these two sections of the rule together, witness McMillan believed that the rule addresses costs that are expended prior to filing a determination of need. Gulf witness McMillan asserted that Gulf's Escambia Site acquisition costs and deferred nuclear site selection costs through the end of 2011 were in accordance with Section 366.93, F.S. Witness McMillan clarified that Gulf relied on Rule 25-6.0423(3), F.A.C., in accruing carrying costs for pre-need site selection costs. Gulf further asserted that witness McMillan's interpretation of the requirements of Section 366.93, F.S., was integral to Gulf's request because the statute provided authorization to record a deferred return. Gulf argued that the rule authorizes the accrual of deferred carrying charges for both site selection costs and preconstruction costs.

Both Gulf's brief and witness McMillan's testimony fail to recognize that Section 366.93, F.S., and Rule 25-6.0423, F.A.C., are not permissive regarding when a site is deemed selected. If the Escambia Site were to be deemed selected without Gulf having obtained an order granting a determination of need petition, as proposed by Gulf, then the explicit rule language would be meaningless and confusing because there would not be any demonstration that a new nuclear power plant was needed to serve retail customers.

We find that the language contained within Section 366.93, F.S., and Rule 25-6.0423, F.A.C., clearly and unambiguously creates a threshold criteria that limits consideration of deferred accounting treatment. Until an order determining need is issued, pursuant to Rule 25-6.0423(2)(e), F.A.C., there are no site selection costs for consideration of deferred accounting treatment under subsection 25-6.0423(3), F.A.C.

Rule 25-6.0423, F.A.C., is clear and unambiguous with respect to the timing criteria addressing when the provisions of Section 366.93, F.S., are ripe for our consideration. The threshold criteria requires Gulf to obtain an order granting a determination of need pursuant to Section 403.519, F.S. Consequently, Section 366.93, F.S., does not support Gulf's proposal that its Escambia Site acquisition and evaluation costs are nuclear power plant site selection costs and that Gulf should be afforded deferred carrying charges on its Escambia Site costs.

IV. TEST PERIOD & FORECASTING

Test Period

We find that the twelve months ended December 31, 2012, is the appropriate test year.

Appropriate Forecasts of Customer, KWH and KW by Rate Class and Revenue Class

We find that Gulf's forecasts of Customer, KWH, and KW by Rate Class and Revenue Class, for the 2012 projected test year are appropriate. Gulf's econometric models and assumptions relied upon are reasonable and consistent with industry practice for developing its forecasts.

Estimated Revenues from Sales of Electricity by Rate Class

We find that Gulf's estimated revenues from sales of electricity by rate class at present rates for the projected 2012 test year are appropriate.

Appropriate Inflation, Customer Growth and Other Trend Factors

We find that the appropriate inflation, customer growth and other trend factors for use in forecasting the test year budget are as follows:

a. Inflation:
   2011 – 2.1%
   2012 – 2.8%
b. Forecasted Composite Wage and Salary Increase Guidelines:
   a. Exempt – 2.5%
   b. Non-exempt – 2.5%
   c. Covered – 2.25%
c. Customer Growth (Retail):
   2012 – 1.2%

Separation of Costs and Revenues Between Wholesale and Retail Jurisdictions

We find that Gulf's proposed separation of costs and revenues between the wholesale and retail jurisdictions is appropriate. Wholesale allocations are predominantly based upon the 12 MCP methodology with some revenues and expenses allocated upon the energy allocator. These methods are based upon cost causation and are consistent with the methodology used in Gulf's prior rate case and approved by this Commission.

V. QUALITY OF SERVICE

We find that the quality and reliability of electric service provided by Gulf is adequate.

VI. RATE BASE

Recovery of Capitalized Items Through the Environmental Cost Recovery Clause (ECRC)

In the instant case, Gulf did not propose to include in rate base any capitalized items currently recovered through the ECRC, except for the Plant Crist Units 6 and 7 Turbine Upgrade Projects (turbine upgrades) discussed below. Gulf indicated in response to staff discovery that consistent with the treatment in Gulf's last rate case, the Company believes it is reasonable and appropriate to continue recovering the capitalized ECRC items in the ECRC. Gulf asserted that once a project has been in-service for 12 months, the impact on customers is essentially the same whether the costs are included in base rates or the clauses; therefore, it is reasonable and appropriate to continue to recover those costs through the clause.

The determination of revenue requirements on projects included in the ECRC and on projects included in base rates essentially are calculated the same way. There is a slight difference in how the average investment balance is calculated. However, the difference in the averaging methodology is negligible. For calculating the average plant investment in the ECRC, the methodology used is to sum the prior month's investment balance and the current month's investment balance, and divide by two. For calculating the average plant investment in base rates, the methodology used is to sum the prior thirteen months of investment amounts and divide by thirteen. Therefore, after a capitalized project has been in-service for thirteen months, the project's capital cost will be the same, and its impact on customers also will essentially be the same whether the costs are included in base rates or the ECRC. As indicated by Gulf, the only adverse impact (to Gulf) that could occur by moving a project that has been in-service for twelve months from the ECRC into base rates relates to the timing of when recovery would begin under each cost recovery mechanism. For example, assuming a project were removed from the ECRC on December 31, 2011, and included in base rates that became effective on March 12, 2012, there would be no recovery of the project's investment for 71 days, or 19 percent of the year. However, we would note that inclusion of projects in the ECRC allows the Company to earn an essentially "guaranteed" return on equity (ROE) on those projects. Inclusion of projects in base rates only provides the Company with the "opportunity" to earn its authorized ROE.

Section 366.8255(5), F.S., provides that "[r]ecovery of environmental compliance costs under this section does not preclude inclusion of such costs in base rates in subsequent rate proceedings, if that inclusion is necessary and appropriate. . ." Therefore, whenever deemed necessary and appropriate, a capitalized project currently recovered through the ECRC can be moved from the ECRC into base rates in a rate proceeding.

Gulf argued that "Section 366.8255(5) does not preclude a shift of capitalized items out of the clause into base rates, if inclusion in base rates "is necessary and appropriate." However, Gulf asserted that no party has provided testimony or evidence that such a shift is necessary and appropriate in this case, except for the turbine upgrades discussed below.

We note that the record in this proceeding has not established a compelling need to move any capitalized items currently in the ECRC into rate base, except for the turbine upgrades. Further, the record has demonstrated no harm to Gulf's customers by Gulf continuing to recover those capitalized items through the ECRC. Based on the record in this case, we find that other than the turbine upgrades discussed below, no other capitalized items shall be moved from the ECRC into rate base.

Inclusion of Plant Crist Units 6 and 7 Turbine Upgrade Projects in Rate Base

The Eligibility for Rate Base Inclusion

By stipulation filed October 28, 2011, in Docket No. 110007-EI and in this docket and approved by us in Order No. PSC-11-0553-FOF-EI,[3] Gulf and the other parties agreed that "recovery of the Crist 6 and 7 turbine upgrades through the ECRC should be discontinued on a prospective basis beginning with the ECRC recovery factors to be applied during 2012, and recovery on a prospective basis should be provided through the base rates." All parties in this case agreed that the turbine upgrades shall be included in this rate base proceeding. Pursuant to our approval of the above-referenced stipulation in Docket No. 110007-EI, we find that it is appropriate for Gulf to include the turbine upgrades in rate base and for this investment to be recovered through base rates rather than through the ECRC.

The Appropriate Amounts for Rate Base Inclusion

As part of its Plant Crist Units 4 through 7 Fuel Gas Desulfurization (scrubber) systems of the CAIR/CAMR/CAVR Compliance Program, which was approved by us in Order No. PSC-07-0721-S-EI,[4] Gulf subsequently decided to install the Crist Units 6 and 7 turbine upgrades to offset increased station losses due to the installation of the scrubber. Gulf claimed that the turbine upgrades are part of the ECRC scrubber project.[5]

In the present proceeding, witness McMillan testified that performing the turbine upgrades in conjunction with the scrubber project was the most efficient decision.

> If these turbine upgrades were performed independently of the scrubber project, they would have been required by environmental regulations to undergo a new source review analysis under the federal Clean Air Act as amended. This would likely have imposed additional costs on the turbine upgrades and could have precluded Gulf from undertaking them as stand-alone projects. Because of their direct tie to the scrubber projects, these turbine upgrades are different than normal maintenance and upgrade projects.

The primary benefits associated with the turbine upgrades are the fuel savings derived from the improved heat rate on the units and the value of the additional 30 MW of capacity. The turbine upgrades appear cost-effective. For the period 2010 – 2021, the estimated total savings would be approximately $94 million, and the estimated savings in every year exceed the annual revenue requirement, which are approximately $75 million in total.

[3] See Order No. PSC-11-0553-FOF-EI, issued December 7, 2011, in Docket No. 110007-EI, In re: Environmental cost recovery clause.
[4] See Order No. PSC-07-0721-S-EI, issued September 5, 2007, in Docket No. 070007-EI, In re: Environmental Cost Recovery.
[5] Attachment 1 of Order No. PSC-11-0553-FOF-EI, pp. 23-24.

With respect to the method used to determine the appropriate amounts of the turbine upgrades for rate base inclusion, Gulf witness McMillan believed that a fair ratemaking treatment to the Company and its customers should:

- Ensure that dollars collected from ratepayers during 2012 equal the amount that would be collected if the turbine upgrade projects were included in Gulf's 2012 rate base at their 13-month average test year balance, and related depreciation expenses were included at their projected amount for the 2012 test year.

- Ensure that Gulf is also able to recover the full costs of these projects (both capital and expenses) beginning in 2013, after all three projects have been placed in service.

Gulf proposed two methods: annualization of the turbine upgrade investment in 2012, with a credit to the customers through the ECRC (primary and preferred method), and a step increase in 2013 (alternative). Witness McMillan testified that the primary proposal would be less confusing to the customers, but the alternative is more consistent with decisions that we have made in the past for other companies.

OPC opposed Gulf's proposals. OPC witness Ramas asserted that through either of Gulf's proposed methods for rate base inclusion, the Company would effectively accomplish the result that it would have realized had the turbine investments remained in the ECRC. OPC argued that Gulf's aim is to import clause-like treatment into setting base rates notwithstanding their ineligibility for this treatment, and that we should reject the attempt.

Mismatching Issue

OPC witness Ramas argued that annualizing the turbine upgrade investments would result in a mismatch of test year investment, revenue, and costs, because the turbines are not to be completed until May and December of the test year.

Gulf witness McMillan countered that there is no mismatch in the 2012 test year under either of the Company's proposals because Gulf is not proposing to achieve full cost recovery before the turbine upgrades are completed. He asserted that OPC witness Ramas would limit Gulf's recovery in base rates to only the 13-month average test year amounts, which would ignore a substantial portion of the investment in these upgrade projects on a going-forward basis. Gulf witness McMillan argued that this, in turn, would result in a mismatch in investment, revenue, and costs starting in 2013, when revenue would not be provided to support the full amount of Gulf's investment in the turbine upgrades. Gulf witness McMillan further contended that witness Ramas' proposed treatment would result in a mismatch of costs and benefits, since customers would be receiving the full benefits of the upgrades through lower fuel costs, but Gulf would be receiving a return on only a portion of the investment that generates those fuel savings.

We note that with either of Gulf's proposals, the Company is not requesting a full annualization of the entire turbine upgrades that would result in rates collected before the two remaining component projects are completed. Gulf's primary proposal contains a credit to the customers through the ECRC to address the "over-collection" in rates in 2012 associated with the Crist 6 HP/IP project to be in-service in May 2012 and Crist 7 LP project to be in-service in December 2012. Gulf's alternative is to include the turbine upgrades at their 13-month average balance in rate base for the test year, and then to implement a subsequent year adjustment to recognize in rates the remaining investments in 2013 and forward. We find that there would be no mismatch in terms of "being used and useful in providing service to" and "recovery of the associated investment from" Gulf's customers.

In its brief, it appears that OPC raised the following argument for the first time, absent any cites to the record in its support:

> If Gulf's earned rate of return during 2013 falls within its authorized range, Gulf will by definition have recovered all costs, including the capital costs, associated with its investment in the turbine upgrades. This is because the turbine upgrades will be within the rate base to which Gulf will relate its net operating income to calculate its earned rate of return.

While we agree that all three turbine upgrade projects will be in-service by 2013, the full investment in certain components (Crist 6 HP/IP and Crist 7 LP projects) of the upgrades will not be "within the rate base" if OPC's approach is adopted. Under OPC's recommended 13-month average approach, recognition in base rates is provided for less than half of the total turbine upgrade investments. Hence, if OPC's approach is adopted, starting January 1, 2013, absent taking further action, Gulf will not be able to recover the full amount of its investments in the turbine upgrades.

No party contested whether the actual costs of the turbine upgrades are reasonable, appropriate, legitimate and not speculative. The record in this case indicates that the in-service portion of the upgrades has resulted in fuel savings, and 2012 will bring more savings to Gulf's customers. No party challenged the cost-effectiveness of the turbine upgrades. We find that Gulf shall be allowed to recover its full investments in the turbine upgrades once all three of its projects are placed in-service. This will ensure a matching of the investment, revenue, and costs starting in 2013 and forward. Moreover, it will enable us to properly recognize and implement the used and useful requirement prescribed by Section 366.06(1), F.S.; and treat the Company and its ratepayers equitably.

Policy Issue

OPC witness Ramas asserted that approving Gulf's proposed treatments would cause us to deviate from its long standing regulatory practices. Gulf witness Deason countered that both of Gulf's proposals are consistent with our policy. He testified that:

> the Commission has a policy of setting rates based on costs that are reasonably known to be incurred during the time that rates are to be in effect. The goal is to set rates on a going forward basis that will enable a utility to recover its costs and have a reasonable opportunity to actually achieve its authorized rate of return.

> The Commission has implemented this policy by various means, including adjustments for known and measurable changes and allowing subsequent year adjustment in rates.

> Witness Deason further specified that the aforementioned policy is reflected in statute:

> Section 366.076(2), F.S., authorizes the Commission to adopt rules that provide for "adjustments of rates based on revenues and costs during the period new rates are to be in effect and for incremental adjustments in rates for subsequent periods." The Commission adopted Rule 25-6.0435, F.A.C., to implement this statutory provision.

Witness Deason testified that our authority to set rates on a going-forward basis has been addressed by the Florida Supreme Court. In a 1985 appeal of our order granting FPL a rate increase for 1984 and a subsequent year adjustment for 1985, the Supreme Court found:

> At the heart of this dispute is the authority of [the] PSC to combat "regulatory lag" by granting prospective rate increases which enable utilities to earn a fair and reasonable return on their investments. We long ago recognized that rates are fixed for the future and that it is appropriate for [the] PSC to recognize factors which affect future rates and to grant prospective rate increase based on these factors.[6]

Gulf witness Deason asserted that OPC's position on this issue, if adopted, would result in regulatory lag, which is the difference in time between when a change in rates is needed due to changes in costs, and when rate change can be implemented. He stated that the current rate case is an appropriate vehicle to recognize the costs of the turbine upgrades. Ignoring the costs now and requiring Gulf to seek recovery by other means would only add an element of increased risk and additional regulatory costs, and this would not be in the customers' best interest.

Although the facts and circumstances were different in each proceeding, step or subsequent year increases have been authorized previously for Florida Power & Light Company (FPL),[7] Progress Energy Florida, Inc. (PEF),[8] and Tampa Electric Company (TECO).[9] We find that both of Gulf's proposed turbine upgrades ratemaking treatments have merit in terms of satisfying the used and useful requirement. We find, however, that adopting a step increase, which is essentially the same as Gulf's alternative, is more compatible with our long-standing regulatory practices concerning the authorization of such increases when warranted.

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[6] Floridians United for Safe Energy, Inc. v. Public Service Commission, 475 So. 2d 241, 242 (Fla. 1985) (citations omitted).

[7] Order No. 13537, issued July 24,1984, in Docket No. 830465-EI, In re: Petition of Florida Power and Light Company for an increase in its rates and charges.

[8] Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In re: Petition for a rate increase by Florida Power Corporation.

[9] Order No. 15451, issued December 13, 1985, in Docket No. 850246-EI, In re: Petition of Tampa Electric Company for authority to increase its rates and charges.; and Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

Tax-related Issue

OPC witness Ramas asserted that if we agree with one of Gulf's proposed recovery methods, then an additional adjustment should be made to annualize the associated impacts on accumulated deferred income taxes.

Gulf opposed OPC's recommendation. Witness McMillan stated that he did not agree that it would be appropriate to adjust one component of the weighted cost of capital. He testified that the turbine upgrade projects were originally removed from the capital structure on a pro rata basis, and should be added back on a pro rata basis, and the approved cost of capital in the test year is the appropriate cost to use for setting rates. He argued that to adjust one source without reflecting the many other changes in the capital structure and the weighted cost of capital is not appropriate. He further argued that to adjust or annualize one component of capital structure or deferred taxes associated with these turbine upgrade projects without also annualizing the other cost components of Gulf's cost of capital is not appropriate. Gulf witness Deason asserted that OPC witness Ramas' recommendation was based on the premise that a portion of the deferred taxes could be traced as being invested in the turbine upgrades. Witness Deason asserted that this, however, was inconsistent with a position taken by OPC witness Woolridge who stated that sources of capital cannot be traced.

We find that an additional adjustment is not necessary in the instant case, to annualize any impacts on accumulated deferred income taxes for the turbine upgrades. Based on the above, we hereby approve a step increase in this case related to the turbine upgrades. While ratepayers will not be paying in 2012 the amount for the portion of the turbine upgrades that is not in-service, Gulf will recover, in 2013 and forward, the full amount of capital expenditures it is incurring to place the entire turbine upgrades into service. The step increase will enable recovery of the full cost of the turbine upgrades once all of the component projects are in-service. By 2013, the entire investment in the turbine upgrades will be in-service and result in significant fuel and capacity cost savings to the customers, and consequently, the Company shall be allowed to recover the full costs associated with the projects. This satisfies the used and useful requirement prescribed by Section 366.06(1), F.S.; results in no mismatch of investment, revenue, and costs starting from January 2013; and is consistent with our practice.

We find that the Crist Units 6 and 7 Turbine Upgrade Projects shall be included in rate base and recovered through base rates rather than through the ECRC. To determine the appropriate amount to be included in rate base, a step increase method shall be used. We find that the following adjustments to rate base and NOI for the 2012 test year are appropriate: (1) increase plant in service by $29,396,000 ($30,424,000 system); (2) increase accumulated depreciation by $1,376,000 ($1,424,000 system); (3) increase depreciation expense by $934,000 ($967,000 system); and (4) decrease income taxes by $360,000 ($373,000 system). In addition, we find a step increase of $4,021,905, effective on January 1, 2013 or the in-service date of the December 2012 upgrade, whichever is later, to capture the incremental full year impact associated with the portion of the turbine upgrades to be in-service in May and December 2012 is appropriate and in the public interest. The calculation of the $4,021,905 step increase is shown on Schedule 6.

Removal of Non-Utility Activities From Plant in Service, Accumulated Depreciation and Working Capital

We find that the appropriate adjustments have been made to remove all non-utility activities in plant in service, accumulated depreciation and working capital by removing $12,518,000 from the Working Capital Allowance. Therefore, no additional adjustments are necessary to working capital.

Incentive Compensation

Gulf witness McMillan stated that it was difficult to determine the dollar amount of capitalized labor because the CWIP projects are not closed into plant in service until the project is completed which may not be in the test year. Therefore, it is difficult to quantify the precise amount of the capitalized payroll that is included in the test year 13-month average plant in service balance. OPC witness Ramas pointed out that Gulf did not provide an estimate. Therefore, witness Ramas calculated the adjustment to plant in service using a 75 percent estimate for the capitalized labor costs and then dividing this amount by 50 percent to estimate a 13-month average test year balance. This methodology resulted in the removal of capitalized incentive compensation of $1,217,206, and corresponding reductions to depreciation expense and accumulated depreciation of $42,967. Gulf did not provide supporting documentation or an estimate of the capitalized labor costs associated with this investment. It is important to have an accurate estimate of the capitalized incentive compensation cost that is reasonable and verifiable if we are to determine the appropriate amount to include in test year rate base and revenue requirement.

We find that zero is the appropriate amount of capitalized incentive compensation to be included in rate base. Therefore, we further find that $1,191,000 ($1,217,206 system) of capitalized incentive compensation be removed from plant in service. Depreciation expense and accumulated depreciation shall each be reduced by $42,049 ($42,967 system). These adjustments are necessary because Gulf has made no attempt to quantify the capitalized labor costs by any method or provide an estimate of their costs. This information is needed to determine eligibility for inclusion of such costs in the test year revenue requirement.

Transmission Infrastructure Replacement Projects

For the period 2006 through projected year-end 2012, $69,056,000 ($71,335,000 system) will have been placed in Transmission Plant in service for Transmission Capital Infrastructure Replacement projects. These costs cover both the replacement of failed equipment and structures and the proactive replacement of equipment and structures which have reached the end of their useful life. In his testimony, Gulf witness Caldwell explained that capital infrastructure replacement projects entail "routine replacements of poles, transformers, voltage regulation equipment, switches, conductors, and other assets." Witness Caldwell also justified the budgeted capital investment through a detailed explanation of the transmission planning process Gulf employed to develop the overall amount. Historically, Gulf's total transmission capital expenditures has grown from $7,872,873 in 2003 to $46,635,680 in 2010. Gulf planned even greater increases in total expenditures for the 2011, 2012, 2013 budget years: $66,748,000,

$70,902,000, and $88,540,000, respectively. In comparison, the transmission capital infrastructure replacement portion, excluding distribution substation replacements, has grown from $3,245,476 in 2003 to $13,552,702 in 2010. Gulf budgeted approximately $15,948,000 in 2011, $4,865,000 in 2012, and $5,030,000 in 2013 for this specific item. The values are consistent with a gradual trend of annually-increasing costs up to 2010, with historical costs greater than the average since 2009.

To explain the significant increase in capital budget starting in 2010, Gulf witness Caldwell asserted in his testimony that, "a significant amount of Gulf's transmission assets were installed in the 1960 to 1980 time period and are now approaching or are at the end of their useful lives." According to witness Caldwell, these components have been used beyond their expected lifespan and replacement is necessary to prevent disruptions in service. In response to concerns regarding the continued increase after 2011 in overall transmission costs, witness Caldwell noted in his rebuttal testimony that the Sinai-Callaway and Crist-Air Products transmission line projects in particular will require major repair and replacement, resulting in the relatively greater amounts starting in 2011.

OPC asserted that Gulf's budgeted amount for 2011 for transmission capital infrastructure replacement projects, excluding distribution substation replacements, is substantially higher than historical levels, and that the capital expense for this item should be reduced by $7,502,049. OPC witness Ramas justified this reduction by a series of calculations replacing the budgeted 2011 and 2012 expense amounts with an average of the historic expenses from 2003 to 2010 of $7,252,301. This resulted in a $8,685,699 reduction to the 2011 budget and a $2,387,301 increase to the 2012 budget. Witness Ramas continued her calculations by taking half of the $2,387,301 increase for 2012 and combining it with the $8,685,699 reduction to 2011 for a net adjustment of $7,502,049. Witness Ramas explained, "in determining the amount of adjustment to plant in service, I have assumed that the projected 2012 expenditures are added evenly throughout the year." Although there is no official explanation or justification for the additional process, we interpreted the most valid reason for this calculation to be an averaging of the adjusted 2012 value ($7,252,301) and the budgeted 2012 value ($4,865,000).

We do not believe that OPC's method of calculating an adjusted expense for the Transmission Capital Infrastructure Replacements is appropriate. Replacement capital costs depend heavily on the lifespan of the item and the incident of it being replaced, which cannot be represented by a trend of historical costs during a period when major replacements were not necessary. Therefore, the averaging of historical costs to predict expenses is not appropriate for capital costs. Averaging in such a method ignores any significant replacements that may be required for those particular years and necessary for reliable service.

Additionally, we note that OPC raised concerns regarding hurricanes that occurred during the 2003 to 2010 time period that could have caused greater costs for infrastructure replacements. However, OPC has not produced any financial information to support this assertion.

Gulf provided information that supports the Company's claim that the transmission infrastructure replacement projects are reasonable and prudent expenditures necessary to provide reliable electric service to its customers. No analyses, records, or discussions presented by OPC refute the legitimacy of Gulf's items required for replacement that cause the significant rise in costs. Therefore, we find that no additional adjustments to Transmission Plant in Service related to Transmission Capital Infrastructure Replacement Projects are warranted.

Although OPC disputed that the total budgeted transmission amounts for 2011 and 2012 are significantly greater than historic levels, OPC's method of analysis ignored the cost of specific transmission items outlined by Gulf that require replacement and repair. Furthermore, there is no substantial evidence presented by the Intervenors that indicated the items of infrastructure replacements are not prudent and necessary. The evidence in the record shows that the Transmission Infrastructure Replacement Projects are reasonable and prudent expenditures necessary to provide reliable electric service to its customers. Therefore, we find that no adjustments to Transmission Plant in Service related to Transmission Capital Infrastructure Replacement Projects are necessary in the instant case.

Distribution Plant in Service

We find that Gulf's requested level of Distribution Plant in Service, $1,029,829,000 ($1,034,325,000 system) shall be reduced by $803,000 ($803,000 system) to reflect an error identified by the Company in the course of responding to discovery. The corrected amount of Distribution Plant in Service, $1,029,026,000 ($1,033,522,000 system), is appropriate to be included in rate base.

Wireless Systems

Gulf witness McMillan testified that Work Order 46C805 included the material costs for a wireless system upgrade and replacement project. He contended that the capitalized material costs reflect the change in the Company's billing procedures. Gulf further specified that after it had implemented the new accounting software (Enterprise Solutions), the cost of the wireless materials were billed by SCS to the Company rather than by Georgia Power Company (Georgia Power) as had been the arrangement previously. Gulf witness McMillan contended that Work Order 46C805 relates to material costs for wireless infrastructure improvements which included wireless and supervisory control and data acquisition (SCADA), voice and data converged network, and power delivery technology improvements (distribution SCADA).

OPC's witness Dismukes referred to Gulf's response to OPC discovery, that acknowledged Work Order 46C805 is the billing for capital equipment required for Converge Networks projects. She stated that the billing occurred after the Company's conversion to Enterprise Solutions. This occurred because the billing flowed from Georgia Power Company Oakbrook warehouse through the SCS work order system, and then billed to the individual companies. She argued that the Company provided no documentation or other evidence that there were savings that would offset the capital dollars for the test year. Therefore, OPC argued that Work Order 46C805 material costs in the amount of $387,596 should be disallowed for the projected test year.

Gulf witness McMillan testified that prior to the introduction of Enterprise Solutions, Georgia Power bought materials in bulk and stored them in a centrally located warehouse in Atlanta. These materials, including IT resources, were made available to the entire Southern Company. Pursuant to this explanation, Georgia Power billed each Southern Company subsidiary directly, including Gulf. After the introduction of Enterprise Solutions, SCS purchased the materials from the warehouse and began to bill the costs to the operating companies. The amount of the bill remained the same, the only difference was the operating companies, including Gulf, were billed by SCS instead of Georgia Power.

The wireless system is included under general plant additions as communication equipment. As stated by witness McMillan, the work order relates to materials that will continue to be necessary for the Company's wireless infrastructure. Also, witness McMillan stated that the amount of the bill did not change.

We find that no adjustment is warranted related to Work Order 46C805. Moreover, we find that since the billing amount did not change and only the Southern Company affiliate that billed the amount changed, there would not necessarily be any savings. Therefore, we find that the wireless systems that are the subject of the Southern Company Services work orders shall remain in rate base.

SouthernLINC Charges Forming the Basis of SCS Work Orders

Gulf included $79,141 in FERC Account No. 397 related to wireless communication equipment. Gulf witness Jacobs testified that this equipment is needed to facilitate hurricane damage restoration and safety for the Gulf customers. He further noted that the Company needs to have a wireless work order system to facilitate the employees' workload and to install additional smart grid equipment on its transmission and distribution systems. This interoperability service will enhance monitoring, switching, and fault location which provide enhanced service for Gulf's customers.

As such, we find that SouthernLINC capitalized charges of $79,141 that are the subject of SCS Work Order 48LC01 shall be included in rate base.

Plant in Service

We find that the appropriate level of plant in service for the 2012 projected test year is $2,641,732,052 ($2,699,343,044 system). This is an increase to plant in service of $29,659,052 ($30,818,044 system) as shown in Table 1 below.

Table 1

2012 Projected Test Year – Plant in Service - Jurisdictional

Description	Gulf	Commission Approved
Plant in Service as filed	$2,612,073,000	$2,612,073,000
Crist Units 6 & 7 Upgrade	61,753,000	29,396,000
Capital Costs - Incentive Compensation	0	(1,191,000)
Transmission Infrastructure Replacements Project	0	0
Distribution PIS	(803,000)	(803,000)
Wireless Systems subject to SCS work orders	0	0
Southern Link Charges Work Order No. 45LC01	0	0
CWIP issues impact PIS	0	2,470,000
Property Held for Future Use	0	167,847
ECCR Adjustment Error	(59,000)	(59,000)
Incentive Compensation	0	(321,795)
Total Adjustments	60,891,000	29,659,052
Adjusted Plant in Service	$2,672,964,000	$2,641,732,052

Depreciation Parameters and Depreciation Rate for AMI Meter Depreciation

We find that the appropriate depreciation parameter for Gulf's AMI meter depreciation is a 15-year life with 0 percent net salvage. The resulting rate is 6.7 percent.

Capital Recovery Schedule for Non-AMI Meters

We find that an eight-year capital recovery schedule shall be established for non-AMI meters (Account 370), modifying the four-year recovery period for the analog meters being retired establish when we approved Gulf's most recent depreciation study in Order No. PSC-10-0458-PSS-EI. Changing the amortization period from 4 to 8 years would result in decreasing the depreciation expense adjustment to NOI by one-half or $886,000 jurisdictional ($886,000 system). The rate base adjustment related to accumulated depreciation would be decreased by $443,000 jurisdictional ($443,000 system). The unrecovered balance to be recovered is $7,088,000.

Accumulated Depreciation

As reflected on the following table, we find that the appropriate level of Accumulated Depreciation for the 2012 projected test year is $1,181,215,612 ($1,208,954,428 system).

Table 2

2012 projected Test Year – Accumulated Depreciation – Jurisdictional

Description	Gulf	Commission Approved
Accumulated Depreciation - MFR B-1	$1,179,823,000	$1,179,823,000
Turbine Upgrade	3,006,000	1,376,000
Capitalized Incentive Compensation	0	(42,049)
Non-AMI Meter Amortization	(443,000)	(443,000)
Construction Work in Progress	0	55,000
ECCR Adjustment Error	458,000	458,000
Incentive Compensation	0	(11,339)
Total Adjustments	3,021,000	1,392,612
Adjusted Accumulated Depreciation	$1,182,844,000	$1,181,215,612

Construction Work in Progress (CWIP)

Gulf stated that the appropriate levels of CWIP for the 2012 projected test year should be $60,912,000 to maintain reliability and meet customer demands. Gulf witness Deason argued that the projects included in CWIP provide a benefit to customers and should be permitted to earn a return. He stated that:

> The $60.9 million represents short-term construction projects which do not qualify for AFUDC. If they are not allowed in rate base, Gulf will be denied an opportunity to earn a return on capital that it has deployed to adequately meet its customers' need for service.

He further stated that we have addressed the proper accounting and ratemaking treatment of CWIP in Order No. 3413.[10] This Order addressed the two options available to companies, which include: (1) charge AFUDC on CWIP and not include CWIP in rate base, and (2) not charge AFUDC and include CWIP in rate base.

OPC witness Ramas testified that:

> Construction Work in Progress (CWIP), by its very nature, is plant that is not completed and is not providing service to customers. It is not used or useful in delivering electricity to Gulf's customers. As a general regulatory principle, CWIP should be excluded from rate base and excluded from costs being charged to customers until such time as it is providing service to those customers.

She further stated that allowing the inclusion of CWIP in rate base would create a mismatch in the ratemaking process since the revenue from new customers are not included in the calculations of the revenue requirement during the period the assets are being constructed. OPC

[10] See Order No. 3413, issued July 26, 1962, in Docket No. 6655-EU, In re: Treatment by public utilities of interest during construction, and consideration of construction work in progress in the rate base.

stated that Gulf has made no showing that CWIP is needed to maintain its financial integrity. In addition, OPC believed it is best to remove all CWIP, including short term projects, from rate base.

We agree with Gulf witness Deason that the inclusion of CWIP (not eligible for AFUDC) in rate base is consistent with our practice. However, while we agree with Gulf's position that non-interest bearing CWIP should be included in rate base, Gulf witness McMillan acknowledged that there were additional adjustments that should be made to plant in service, CWIP, accumulated depreciation, and depreciation expense to close the projects. The adjustments acknowledged by witness McMillan that impacted CWIP were provided in Exhibit 98 (Nos. 175 through 177) and are shown in Table 3 below. These adjustments were for projects completed prior to December 2012, cancelled or delayed projects, or projects not closed to plant-in service in the 2011 budget for the following plant functions: (1) Steam Production-Minor Projects, (2) Other Production--Minor Projects, (3) Transmission-Minor projects, and (4) General Plant-Minor Projects. In addition, the adjustments to close the projects resulted in a decrease to CWIP of $2,463,000 ($2,530,000 system) and increases to: (1) plant in service of $2,470,000 ($2,633,000 system), (2) accumulated depreciation of $55,000 ($57,000 system), and 3) depreciation expense of $102,000 ($106,000 system). The overall 2012 CWIP adjustments are provided in Table 3 below.

Table 3

Construction Work In Progress - 2012 Adjustments		
Description	Gulf	Commission
CWIP in Rate Base	$60,912,000	$60,912,000
Item No. 175	0	(2,007,000)
Item No. 176	0	(243,000)
Item No. 177	0	(213,000)
Total Adjustments	0	(2,463,000)
Adjusted CWIP	$60,912,000	$58,449,000

Therefore, we find that the appropriate level of CWIP for the 2012 projected test year is $58,449,000 ($60,087,000 system), which is a reduction of $2,463,000 ($2,530,000 system). As discussed above, the adjustments to close the projects to plant in service decreases CWIP, requiring additional adjustments to increase plant in service by $2,470,000 ($2,633,000 system), accumulated depreciation by $55,000 ($57,000 system), and depreciation expense by $102,000 ($106,000).

Plant Held for Future Use Associated with the Caryville Plant Site

Gulf witness Burroughs stated that the Caryville site consists of approximately 2,200 acres of land in Holmes County with a book value of $1,356,000. He stated that the site was certified under the Power Plant Siting Act and is suitable for a steam electric generating plant. He further stated that it was evaluated for a nuclear site and that it was determined it was not a viable option for nuclear generation.

At the hearing, witness Burroughs was specifically asked if the Company had any planned generation units for the next ten years. He answered that, "[w]e don't have any particular units planned for development in the next ten years at Gulf Power." He was also asked if Gulf had any plans to put a power plant on the Caryville site. He testified as follows:

> We don't have any plans in the present or in the near future to put a facility on the Caryville site. It is an option for us, and we will use it depending on what loading is, what the economic growth is, and whatever environmental regulations that come down in the near future that will force us into one direction or the other. So it serves as an option.

OPC and FEA took no position. FRF recommended that there should be an adjustment related to the Caryville site, but provided no details related to an adjustment. FIPUG recommended the Caryville site be removed from rate base since it is no longer prudent for Gulf to continue to hold the site.

As noted above, the Company acknowledged that there were no plans to construct a generating plant at the Caryville site. Although the property was purchased in 1963, the Company placed the land in plant held for future use (PHFU)[11] during a 1972 rate case. The land for the Caryville site at that time totaled $126,417.[12] Additionally, the Caryville site was expanded by the purchase of more land in the amount of $1,255,585, and was placed in PHFU in a 1980 rate case.[13] Witness McMillan acknowledged that there were non-utility activities occurring at the site that provide revenue to Gulf which benefit the ratepayers. Of the 2,200 acres of land, the Company has leased approximately 1,485 acres to the Brunson Hunting Club. The Company began leasing to the hunting club on November 9, 2000, and recently renegotiated a new lease on September 30, 2011, which will end on July 31, 2012. Additionally, the Caryville and Mossy head land is being used to grow or produce timber. There were timber sales in 2011 totaling $124,477, of which $61,367 was from the land currently in PHFU. Furthermore, in 2011, the Company received revenue from leasing the land as farmland and a residential house, which totaled $15,444.

The Company accounts for the revenue by: (1) crediting timber revenue to "Other Electric Revenue - P & L Natural Resources," and (2) crediting lease revenue to "Rent From Electric Property-Miscellaneous." In total, the Company has received $76,811 in revenue that is recorded above-the-line for PHFU. The current assessed value of the Caryville plant site is $429,754. Other than the revenue from leasing and timber sales, the Company stated that the site continues to be evaluated as a potential generating site during its planning process.

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[11] PHFU stands for both "plant held for future use" and "property held for future use" because the terms are synonymous.

[12] See Order No. 5471, issued June 30, 1972, in Docket No. 71342-EU, In re: Petition of Gulf Power Company for authority to increase its rates and charges so as to give said utility an opportunity to earn a fair return on the value of its property used and useful in serving the public, p. 10.

[13] See Order No. 9628, issued November 10, 1980, in Docket No. 800001-EU (CR), In re: Petition of Gulf Power Company for an increase in its rates and charges, p. 7.

Witness Burroughs testified that it was his understanding that the Caryville site is certified for two 500 megawatt coal units. He further stated that the Caryville site also could support combined cycle units, combustion turbines, and other options except for the nuclear option.

We find that the Caryville site shall remain in PHFU because it already has been certified under the Power Plant Siting Act and can support many different types of generation facilities. In addition, the revenue received from timber sales and leasing of the land helps to offset a portion of the revenue requirement for the site. Thus, we find that no adjustment shall be made to PHFU for the Caryville plant site.

North Escambia Nuclear County Plant Site

In this proceeding, Gulf contended that the $27,687,000 of North Escambia site costs should be included in rate base. In support of this assertion, Gulf witness Burroughs stated that, as part of the ongoing planning processes, the Company evaluated many generation resources to meet its future needs. He further stated that prudence dictated the Company needed to consider all viable technology types that would provide the greatest benefit to customers. Also, he stated that the Company employed a broad technology evaluation approach to evaluate land held for future use. He argued that the resource planning process would not be constructive for the full range of resources if the land was not available for consideration. Furthermore, the Company must make the appropriate investments in land that would support any or all of the options.

Witness Burroughs testified that the Company's next planned addition for capacity will not be until 2022. He further testified that:

> The primary benefit of that planning flexibility has been Gulf's ability to avoid having to commit to specific generation technologies during a time of high uncertainties associated with potential environmental requirements. There are major environmental initiatives being proposed that could change the face of the electric utility industry. These potential environmental regulatory requirements could drive new generation additions.

He argued that due to uncertainties, there are situations where nuclear could be a cost effective solution to meet long term generation additions. In addition, while considering nuclear technology, the Company reviewed over two dozen locations before deciding on the purchase of the 4,000 acre Escambia Site. The site was more suitable than the other locations due to its proximity to transmission, natural gas pipelines, railroad facilities, major highways, and access to water. Further, the site had a limited number of individuals and home owners. In addition, the site was suitable for other generation technologies including coal, gas, and renewables. The Escambia Site was owned by 35 property owners, including timber companies, who were the largest land holders. Witness Burroughs further stated that, "Gulf's decision to purchase land as a site suitable for new generation, including possible nuclear generation, is reasonable, prudent and necessary to continue to provide our customers with the most cost effective generating resources in the future."

Witness Burroughs testified that the Company had no units planned for development in the next ten years. He also testified that, as stated in the Company's 2011 Ten Year Site Plan, the Company's next need for capacity would be 30-megawatts. He further testified that in 2023, there would be a need for an additional 885 megawatts due to the expiration of the Central Alabama Power Purchase agreement.

Gulf witness McMillan testified that the incurred costs for the Escambia Site and other charges should be included in rate base to defer nuclear site selection costs. He further stated that according to Section 366.93, F.S., the costs and a return were deferred by the Company through the end of 2011. Furthermore, he believed that: (1) nuclear is a viable option that will benefit the customers based on a range of scenarios; (2) the Escambia Site is the only site suitable for nuclear generation in Gulf's service territory; (3) the purchase of the site is necessary to allow Gulf to preserve a nuclear option for its customers; and (4) the site provides water, rail, and gas which is necessary for other forms of generation.

Witness McMillan testified that the deferred charges included preliminary survey site selection type costs and a deferred return. He further testified that the statute instructed us to set rules to implement that statute. Witness McMillan stated that Rule 25-6.0423, F.A.C., defines site selection and site selection costs as:

> Site selection. A site will be deemed to be selected upon the filing of a petition for a determination of need for a nuclear or integrated gasification combined cycle power plant pursuant to Section 403.519, F.S.
>
> Section 4, Site selection costs. After the Commission has issued a final order granting a determination of need for a power plant pursuant to Section 403.519, F.S., a utility may file a petition for a separate proceeding to recover prudently incurred site selection costs.

Witness McMillan acknowledged that the Company had not filed a petition for nor obtained an order granting a need determination for the nuclear plant. He stated that the Company had deferred the filing for a determination of need.

Gulf witness Alexander testified that the $27,687,000 for the Escambia Site consisted of site acquisition and costs other than site acquisition. She further stated that the costs included approximately $18.8 million for site acquisition and $8.8 million for costs other than site acquisition. She argued that based on the Company's request, the revenue requirement for the site was approximately $3.1 million, which is less than 0.6 percent of total base rates. Furthermore, the inclusion of the Escambia Site in rate base would amount to approximately 26 cents on a 1,000 kilowatt hour residential bill.

Witness Alexander contended that the site costs were initially incurred in 2007 and the site acquisition costs were incurred from 2008 through 2011. Also, she stated that the carrying costs were accrued on a monthly basis and will continue until the costs go into rate base. She argued that considering all the factors and the Company's extensive studies, it was apparent that a self-build nuclear option was feasible. These factors were: (1) federal and state government targeting reductions of greenhouse gas (GHG) emissions; (2) state policy promoting the development of nuclear power; (3) Gulf's capacity needs; (4) possible coal retirements; and (5) high gas prices.

Witness Alexander argued that the Company's consideration of the nuclear option was due to possible coal retirements and forecasted system load growth requirements. Furthermore, she maintained that if the Company pursued the nuclear option, it could "bridge its needs" with the use of Power Purchase Agreements (PPAs) to bridge capacity to move its 2009 forecasted need to 2014. She stated that circumstances changed and the Company deferred its nuclear licensing, permitting, and determination of need efforts for the future.

Witness McMillan argued that Section 366.93, F.S., provided authorization to record a deferred return on assets. He believed that there existed an apparent misunderstanding with the Intervenor witnesses about the role that Section 366.93, F.S., played for the inclusion of the Escambia Site costs. He argued that the Company was requesting to discontinue the deferral and move the dollars into rate base based on our general ratemaking authority. He further argued that the request was not based on specific provisions of Section 366.93, F.S.

OPC witness Schultz argued that Gulf neither requested nor filed a petition for determination of need. He contended that the Company acknowledged that it does not have plans to file a petition for a determination of need for a nuclear plant in the near future. He further argued that since no petition for a determination of need was filed to satisfy the requirements of Section 366.93(3), F.S., then the costs associated with the purchase of the land should not be included in PHFU. It was his understanding both FPL and PEF "have been delaying the construction of nuclear plants further into the future because they cannot be justified on the basis of need." Furthermore, he argued that it was hard to believe that a company which is so much smaller than FPL and PEF could justify a nuclear plant to meet its own needs.

Witness Schultz further stated that in Gulf's response to OPC discovery, Gulf's Ten-Year site plans showed a "potential generation need of approximately 30 MW in 2022." He contended that the amount does not justify the addition or construction of a nuclear plant with 1150 MW of capacity or the recovery of $26 million in PHFU. He maintained that a base rate case is not the appropriate proceeding to evaluate future plant growth and needs. He argued that if there were a situation where nuclear was the solution, then the Company should have presented it to us in the form of a petition for determination of need in order to justify any future generation additions, or otherwise demonstrated that a nuclear is cost effective option for the ratepayers.

FIPUG argued that the inclusion of the Escambia Site to preserve the nuclear option was not appropriate. In addition, FIPUG further argued that Gulf did not show that the Escambia Site would be used for utility purposes in the reasonably near future and thus no carrying charges should be accrued on the site.

FRF witness Chriss testified that Gulf will not use the Escambia Site before 2022 and maybe not at all. He further stated that according to the Company's 2011-2012 Ten Year Site

Plan, there were no plans to add any generating capacity until after 2020. He argued that when there is a need for capacity, then Gulf could evaluate the existing sites at Plants Crist, Smith, Scholz, and the greenfield site at Shoal River in Walton County. He argued that because the Company has no plans to use the site in the next ten years, we should reject the Company's request to earn a return on a future power plant site that is not used and useful for the ratepayers.

FEA witness Meyer testified that Gulf was premature to include the investment for the Escambia Site based on Section 366.93, F.S. He further stated that there was no testimony from the Company's witnesses that we had approved a determination of need. Also, he contended that it was unclear if Gulf could accumulate the carrying costs prior to our granting the need determination. He maintained that the Escambia Site costs should be disallowed.

We have reviewed the site acquisition and investigation costs provided by Gulf. The documents revealed a steady increase in the cost of land and carrying charges. For instance, in reviewing a response to OPC discovery, the Company stated that as of December 31, 2010, deferred costs related to pursuing the nuclear option at the Escambia Site were $12,814,000 ($12,381,000 jurisdictional) and as of July 31, 2011, were $19,582,000 (18,920,000 jurisdictional). Moreover, in response to staff discovery, the Company stated that the total project cost to date was $19,933,632 ($19,260,085 jurisdictional) as of September 2011. The Company asserted that the variance was due to the timing of land acquisitions. In their testimony, Gulf witnesses Burroughs and McMillan included $27,687,000 of deferred nuclear site costs in PHFU for the period ending December 31, 2012. Gulf provided a detailed breakdown of the $27,687,000 site costs. Furthermore, the Company projected 2012 carrying costs in the amount of $1,046,131, which increased the total to $28,734,000. In its working capital adjustment, Gulf removed the 2012 carrying cost of $1,046,131. However, the 2012 carrying cost was not included in the Company's adjustment to increase PHFU for the Escambia Site. The Company concluded that if the deferred site costs were included in the 2012 rate base, there would not be any carrying costs for 2012. A summary of the above discussed site costs excluding the 2012 carrying charges is shown in Table 4 below.

Table 4

North Escambia County Plant Site Costs

	System	Jurisdictional
Land Costs	$18,140,286	$17,527,000
Other Site Acquisition Costs	778,485	752,000
Site Investigation Costs	4,548,772	4,395,000
Need Determination Filing	187,238	181,000
Project Support Costs	650,742	629,000
Project Frank	370,460	358,000
UWF Study	33,620	32,000
Subtotal Land Costs	24,709,603	23,874,000
Carrying Costs thru 12/31/11	2,977,838	2,877,000
Total Site Costs	$27,687,441	$26,751,000

Gulf witness McMillan explained that the costs are currently classified on the Company's books as regulatory assets based on the deferred accounting requirements of Rule 25-6.0423, F.A.C. However, as discussed previously, Section 366.93, F.S., and Rule 25-6.0423, F.A.C., establish a threshold criteria that Gulf must satisfy before it can calculate a deferred carrying charge for the 4,000 acre Escambia Site and the costs of associated evaluations as nuclear site selection costs. As discussed previously, Gulf has not satisfied the threshold criteria that it must obtain an affirmative order granting a determination of need for a nuclear power plant, nor has the Company petitioned us for authorization to use the alternative deferred accounting treatment for the expenses associated with the 4,000 acre Escambia Site and the costs associated with the evaluations as nuclear site selection costs. Unless specifically authorized by statute or rule, a regulated company must have the approval of its regulator to defer costs and create a regulatory asset.[14]

We agree with OPC, FIPUG, FRF, and FEA that: (1) the Caryville site is available for any needed future generating plant(s); (2) Gulf may share the ownership of the Escambia Site with its sister companies; and (3) there was not an order granting a determination of need that would allow the Company to petition for and the Commission the opportunity to review the "nuclear option" and all the various corresponding costs. In light of our approval of Gulf's retention of the Caryville site and the other available sites already included in rate base, we believe that Gulf has sufficient options for its future generation needs. Moreover, we find that Gulf has failed to support the inclusion of the North Escambia County Nuclear plant site and associated cost in PHFU. Therefore, PHFU shall be reduced by $26,751,000 ($27,687,000 system). In addition, Gulf shall not be permitted to accrue AFUDC for this site. As discussed above, Gulf has neither obtained the requisite order granting a determination of need nor has it received the necessary authorization to accrue AFUDC on the site costs. Therefore, Gulf shall be required to adjust its books to remove the $2,977,838 in accrued carrying charges.

[14] See Order No. PSC-08-0616-PAA-GU, issued September 23, 2008, in Docket No. 080152-GU, In re: Petition for approval of recognition of a regulatory asset under provisions of Statement of Financial Accounting Standard (SFAS) No. 71, by Florida City Gas, p. 2.

Property Held for Future Use

Two of the properties in PHFU, totaling $28,061,000 ($29,043,000 system) were identified and discussed above. The remaining properties included in this account amount to $4,172,000 ($4,309,000) as shown on MFR Schedule B-15.

Moreover, our staff has identified two additional properties that shall be removed from PHFU, namely the Sandestin substation land $86,000 ($86,000 system) and the Panama City Office land $81,847 ($83,000 system). The Sandestin substation site is currently being used as a substation and the land should have been transferred to plant in service along with the substation facilities. The land actually was transferred in April 2011. The Panama City Office land is being held for a future parking lot expansion, but is currently being used as a pole yard and for training. The Company intended to move the land to plant in service before the end of 2011.

As discussed above, the Escambia Site and other charges totaling $26,751,000 ($27,687,000 system) shall be removed from PHFU. In addition, the Sandestin and Panama City land shall be removed from PHFU and placed into plant in service requiring an additional adjustment of $167,847 ($169,000 system). In total, we find that PHFU shall be reduced by $26,918,847 ($27,856,000 system) resulting in an adjusted level of $5,314,153 ($5,496,000 system).

Fuel Inventories

We find that Gulf's requested fuel inventory $83,871,000 ($86,804,000 system) shall be reduced by $338,174 ($350,000 system) to reflect the necessary adjustment for Scherer In-transit fuel. In addition, consistent with Gulf's response to staff discovery the fuel inventory shall be reduced by $$443,491 ($459,000 system) to reflect the test year gas storage inventory amount based on updated gas prices for 2012. The result of these two adjustments is a total test year fuel inventory amount of $83,089,332 ($85,995,000 system).

Storm Damage Reserve, Annual Accrual, and Target Level Range

Our resolution of this matter is predicated upon our decisions on two components: Gulf's appropriate annual storm damage accrual and the target level of Gulf's storm damage reserve. Gulf's current accrual is $3.5 million and its storm reserve range is $25.1 to $36 million. The record reflects that four parties offered proposals on one or both of these matters: Gulf, OPC, FIPUG, and FEA.

Gulf witness Erickson sponsored the storm damage study that was prepared for Gulf by EQECAT. The storm study is comprised of two sections. The first section is The Hurricane Loss Analysis section, which uses a probabilistic approach that considers potential hurricane characteristics and equivalent losses from thousands of random variable hurricanes. The second section is The Reserve Performance Analysis, which is a financial analysis simulation that evaluates the performance of the reserve in terms of the expected balance in the reserve and the likelihood of positive reserve balances over a five-year period, incorporating the potential uninsured loss amounts determined in the Hurricane Loss Analysis, at the annual accrual level.

This study indicated that Gulf's Expected Annual Damage (EAD) is $8.3 million, of which Gulf proposed that $6.8 million be funded through the annual accrual. Witness Erickson proposed that the target reserve range be increased to a range of $55 to $98 million. During cross-examination, witness Erickson was questioned at length regarding her detailed knowledge of the storm study. For example, she was asked if the persons that work with EQECAT would be the ones who know the intricacies of how the storm study works. Her response was yes. She also stated that she is only familiar with certain details of the storm study about which she asked the preparers of EQECAT. In addition, she stated in cross-examination that she does not have any experience in running the EQECAT computer simulation model, or any of the other currently approved models. During her deposition, witness Erickson was questioned by FIPUG about her knowledge of the study. Counsel for FIPUG inquired specifically if witness Erickson considered herself to be an expert in performing analytical studies that the EQECAT outfit completed. Witness Erickson responded by acknowledging that she was not an expert in performing analytical studies such as those performed by EQECAT.

Accordingly, we find that Gulf witness Erickson lacks sufficient familiarity with the EQECAT model, including its inputs and its algorithms, to attest to the reasonableness of the storm study and its results submitted in this proceeding. We note that no other Gulf witness testified with respect to the study.

Our staff as well as OPC sent multiple discovery questions in an attempt to obtain an understanding of the EQECAT model's inputs and internal processes. Gulf witness Erickson testified that she was responsible for responding to these discovery questions. However, neither our staff nor OPC was able to determine and track the various calculations and iterations of the model that ultimately yielded the proposed $8.3 million EAD which was the basis for Gulf's proposed $6.8 million annual accrual. Therefore, we find that Gulf's proposed annual accrual of $6.8 million is not sufficiently supported by the evidence in the record.

In contrast to the approach used in the EQECAT study, OPC witness Schultz derived his recommended annual accrual using historical data covering the period 2001-2010 on storm damage actually incurred by Gulf. He first excluded the costs associated with the storms in 2004 and 2005, and then averaged the remaining amounts. Witness Schultz testified that it was appropriate to exclude the 2004-2005 data because it reflected extraordinary storms. This calculation yields $575,566, which the OPC witness rounded up to $600,000 to arrive at his recommended annual accrual.

Gulf witness Erickson disagreed with the OPC proposal. She disputed the claim that the 2004-2005 storms that hit Gulf's territory were extraordinary, noting that they were Category 3 storms. Witness Erickson observed that by including the 2004-2005 storm data, the 10-year average would be $15.7 million.

Witness Erickson responded to OPC witness Schultz's claim that the study's results were predetermined to reflect what amount the Company wanted to collect in rates. Witness Erickson countered this claim, noting: "The ground work for this Study began early in 2010, since the Study was required to be filed with the Commission in January, 2011. This filing was independent of any rate case proceedings. There was absolutely no communication with the consultant that tried to direct or sway the outcome of the Study."

We agree with witness Erickson that it was unreasonable for the OPC witness to exclude the 2004-2005 storm data from his analysis. Excluding storm damage costs for Hurricanes Ivan, Dennis, and Katrina effectively assigns a zero weighting to the likelihood of storms of such magnitude occurring in the future. While acknowledging that the computational approach employed by OPC witness Schultz does not readily lend itself to accounting for probabilities of occurrence, we believe assigning a zero probability that storms such as those that hit Gulf's territory in 2004-2005 will recur, is questionable. Accordingly, we do not believe that OPC witness Schultz's recommended annual accrual level or methodology is appropriate.

FIPUG witness Pollock and FEA witness Meyer advocated similar positions. FIPUG witness Pollock testified that the annual accrual should remain at its current level of $3.5 million. FEA witness Meyer proposed an annual accrual of no higher than $5.0 million, which he derived by increasing the approved accrual of $3.5 million for inflation. However, in its brief FEA appeared to have modified its position: "FEA recommends that the Commission not establish the annual accrual to exceed $5.0 million, but support FIPUG's position of no change." On balance, we find that the record supports maintaining the existing annual accrual at $3.5 million. No pressing need has been identified to warrant an increase in the accrual at this time. As such, we find that a $3.5 million accrual coupled with the 2011 year-end reserve level of approximately $31 million will be sufficient to cover the costs of most, but not all storms. If circumstances change, it will be appropriate to revisit this decision in a future proceeding.

While we find that the annual accrual shall remain unchanged, we believe there is merit in making a modest adjustment to the target reserve level. The current range of $25.1 to $36 million was set over 14 years ago. Gulf's storm study indicates that a reserve of $52 million is adequate to cover all Category 1 and Category 2 hurricanes. In her rebuttal testimony, Gulf witness Erickson asserted that if the target reserve level had been adjusted for inflation, as FEA witness Meyer did to the current annual accrual to arrive at his proposal in his testimony, the range would be approximately $48 to $69 million.

Thus, we find that the target reserve level shall be increased slightly, to $48 to $55 million. A range of $48 to $55 million represents a composite of the amounts suggested by Gulf witness Erickson and FEA witness Meyer. The upper end of the range in the amount of $55 million is slightly above the $52 million amount indicated by Gulf's storm damage study which is sufficient to cover all Category 1 and 2 storms. However, we have considered, as Gulf witness Deason stated in his testimony, that charges are made against the reserve for items in addition to charges associated with property damage from storms. While storms are the main reason for the reserve, the reserve may be charged for damage resulting from events such as a fire or other natural occurrences. The totality of the record reflects that a target reserve range of $48 to $55 million will be sufficient to cover the costs of all Category 1 and Category 2 storms, with a small margin for unnamed storms and other damage. Thus, this reserve level best fits our goal that the reserve shall be sufficient to cover most, but not all storms. At this time, it would be premature to determine whether or not the accrual shall cease when the upper end of the target range is achieved. Rather, in the event that the target reserve level is achieved, this question shall be analyzed and addressed at that time.

We find that the annual storm damage accrual shall remain at its current annual level of \$3.5 million but with a new target range of \$48 to \$55 million. This results in a decrease in jurisdictional O&M expense of \$3,173,382 (\$3,300,000 system) and an increase in the jurisdictional working capital of \$1,586,500 (\$1,650,000 system) for the test year. The storm damage accrual shall not stop when the maximum target level is achieved. Rather, we find that it would be more appropriate for this issue to be readdressed if and when the target level is actually achieved.

Unamortized Rate Case Expense

Gulf included \$2,450,000 of unamortized rate case expense in working capital for 2012. Gulf witness McMillan stated that rate case expenses are prudently incurred business expenses. He further asserted that these costs should be allowed to be recovered as well as earn a return on the unamortized investment. Gulf noted that we authorized the Company to recover unamortized rate case expense in Docket No. 010949-EI.[15]

In contrast, the Intervenors argued that unamortized rate case expense should not be included in working capital because of our long-standing practice in electric and gas cases of excluding the unamortized rate case expense from working capital.[16] Moreover, the Order cited by Gulf in support of recovery of unamortized rate case expense, Order No. PSC-02-0787-FOF-EI issued in Docket No. 010949-EI, does not include an adjustment to reduce unamortized rate case expense nor does it show the inclusion of unamortized rate case expense in working capital. OPC, FIPUG, FRF, and FEA agreed that unamortized rate case expense should be removed from working capital.

As noted above, we have a long-standing practice in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases.[17] The rationale for this position is that ratepayers and shareholders should share the cost of a rate case; i.e., the cost of the rate case would be included in O&M expense, but the unamortized portion would be removed from working capital. This practice underscores the belief that customers should not be required to pay a return on funds spent to increase their rates.

While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital. The

[15] See Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.
[16] See Order Nos. 23573, issued October 3, 1990, in Docket No. 891345-EI, In re: Application of Gulf Power Company for a rate increase; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket 080366-GU, In re: Petition for rate increase by Florida Public Utilities Company; and Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., pp. 71-72.
[17] Id.

difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period.[18] While unamortized rate case expense does not earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the four year amortization period ends. Thus, the amount in O&M expense continues to be collected after total rate case expense has been recovered.

For the foregoing reasons, we find that the unamortized rate case expense of $2,450,000 shall be removed from working capital consistent with our long-standing practice.

Working Capital

We find that the appropriate 13-month average of working capital for the 2012 projected test year is $148,963,835 ($153,435,000 system). The components of this calculation are contained in Table 5 below.

Table 5

2012 Projected Test Year – Working Capital - Jurisdictional

Description	Gulf	Commission Approved
Working Capital as filed	$150,609,000	$150,609,000
Fuel Inventory Adj	(338,000)	(338,174)
Gas Storage Inventory	(443,000)	(443,491)
Storm Damage Reserve	0	1,586,500
Unamortized Rate Case Exp.	0	(2,450,000)
Total Adjustments	(781,000)	(1,645,165)
Adjusted Working Capital	$149,828,000	$148,963,835

Appropriate Test Year Rate Base Amount

We find that the appropriate 2012 projected test year rate base is $1,673,243,428 ($1,709,406,616 system), which is a reduction of $2,760,572 ($2,618,384 system) from Gulf's original requested level, as shown in Table 6.

[18] See Section 367.0816, F.S.

Table 6

2012 Rate Base - Jurisdictional			
	Gulf as Filed	Gulf Revised	Comm. Approved
Utility Plant-In-Service	$2,612,073,000	$2,672,964,000	$2,641,732,052
Less: Accumulated	1,179,823,000	1,182,844,000	1,181,215,612
Net Plant-In-Service	1,432,250,000	1,490,120,000	1,460,516,440
CWIP	60,912,000	60,912,000	58,449,000
Property Held for Future Use	32,233,000	32,233,000	5,314,153
Net Utility Plant	1,525,395,000	1,583,265,000	1,524,279,593
Working Capital	150,609,000	149,828,000	148,963,835
Total Rate Base	$1,676,004,000	$1,733,093,000	$1,673,243,428

VII. COST OF CAPITAL

Accumulated Deferred Taxes

In its MFRs, Gulf recorded a balance of jurisdictional Accumulated Deferred Income Taxes (ADITs) to include in the Company's capital structure for the test year of $257,098,000. Gulf witness McMillan testified that Gulf's capital structure has been reconciled to rate base pro rata over all sources of capital consistent with our prior practice. Witness McMillan also stated that tax normalization problems could result if the treatment is not consistent for all regulatory purposes.

OPC argued that Gulf's deferred taxes should be decreased to $245,119,000, which is a reduction from Gulf's requested balance of $257,098,000 and reflects a pro rata reduction associated with OPC's recommended rate base adjustments. OPC witness Ramas asserted that if we agree with recovery of the two turbine upgrade projects, an adjustment to ADITs should either increase the amount of deferred income taxes in the capital structure or lower rate base by $916,000 for the resulting impact of those projects on deferred income taxes.

ADITs represent a cost-free source of funds resulting from timing differences associated with depreciation for book purposes versus depreciation allowed for tax purposes. As the deferred taxes are included in the capital structure at zero cost, the increase in the percentage of the capital structure associated with deferred taxes is a benefit to ratepayers as it reduces the overall required rate of return.

We find that Gulf has reasonably relied on our previous treatment of ADITs to include in the capital structure. Additionally, in reconciling rate base and capital structure, Gulf and the other parties agree the capital structure shall be reconciled to rate base pro rata over all sources of capital. By adjusting the capital structure on a pro rata basis for the Crist Units 6 and 7 turbine upgrades, deferred taxes are increased in proportion to the percent of deferred taxes in the capital structure.

On the basis of the foregoing, we find that the appropriate amount of accumulated deferred taxes to include in Gulf's capital structure for the 2012 projected test year is $256,674,530.

Appropriate Amount and Cost Rate of the Unamortized Investment Tax Credits

In its MFRs, the Company proposed that the balance of ITCs to be included in its capital structure for the test year is $2,929,000, with a cost rate of 8.45 percent. Witness McMillan testified that the cost for ITCs of 8.45 percent was calculated in accordance with current IRS regulations and our practice, using the weighted average of long-term investor sources of capital. Gulf updated the balance of unamortized ITCs to be included in its capital structure for the test year to $3,026,000; and, modified the ITC cost rate to 8.34 percent to reflect changes in the stipulated cost rates of long-term debt (5.26 percent) and preferred stock (6.39 percent).

OPC asserted that Gulf's requested balance of ITCs should be reduced by $136,000 related to OPC's recommended adjustments to rate base to reflect a reconciled balance of $2,793,000. OPC further asserted that the appropriate ITC cost rate should be 7.10 percent, calculated as a fall out by taking the weighted average cost of short-term debt, long-term debt, preferred stock and common equity as approved by us. FIPUG and FRF agreed with OPC on this issue while FEA adopted the position of OPC on this issue.

We find that Gulf's methodology for calculating the balance and cost rate of ITCs is appropriate and is in accordance with IRS requirements and our past practice. Our staff recalculated the ITC cost rate based on these adjustments to rate base and an ROE of 10.25 percent, resulting in an ITC balance of $2,924,176 and a 7.66 percent weighted average cost rate. The weighted average cost rate for ITCs was calculated using long-term investor sources of capital in accordance with current IRS regulations and our past practice.

Based on the above, we find that the appropriate amount and cost rate of unamortized ITCs to include in Gulf's capital structure for the 2012 projected test year are $2,924,176 and 7.66 percent, respectively.

Cost Rate for Preferred Stock

We find that the appropriate cost rate for preference stock for the 2012 projected test year is 6.39 percent.

Cost Rate for Short Term Debt

We find that the appropriate cost rate for short-term debt for the 2012 projected test year is 0.13 percent.

Cost Rate for Long Term Debt

We find that the appropriate cost rate for long-term debt for the 2012 projected test year is 5.26 percent.

Return on Equity

The statutory principles for determining the appropriate ROE for a regulated utility have been framed by the U.S. Supreme Court in its Hope and Bluefield decisions.[19] These two decisions define the fair and reasonable standards for determining rate of return for regulated public utilities. These standards provide that the authorized ROE for a public utility should be: (1) commensurate with returns on investments in other enterprises of similar risk; (2) sufficient to maintain the financial integrity of the utility, and (3) sufficient to maintain its ability to attract capital under reasonable terms.

While the legal and economic concepts of a fair rate of return are straight forward, the actual implementation of these concepts is controversial. Unlike the cost rate on debt that is fixed and easily measured due to its contractual terms, the return on equity is a forward-looking concept that must be estimated. Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and the ex ante Risk Premium (RP) model are generally recognized as being consistent with the standards for determining a fair rate of return as set forth in the Hope and Bluefield decisions.

Three witnesses testified in this proceeding regarding the appropriate ROE for Gulf. These witnesses also provided an appropriate ROE in this case. Gulf witness Vander Weide recommended an ROE of 11.7 percent. OPC witness Woolridge recommended an ROE of 9.25 percent. FEA witness Gorman recommended an ROE of 9.75 percent. Gulf's current authorized ROE is 11.75 percent and was set in 2002.[20] Because Gulf is a wholly-owned subsidiary of Southern Company, its common stock is not publicly traded and the ROE must be estimated by applying ROE models to a proxy group of companies with comparable risk to Gulf. All three witnesses used variants of generally accepted financial models to derive their respective recommended ROE for Gulf. The dispute among the parties is not about the models themselves, but how the models are applied and the assumptions and inputs used in the models.

All three witnesses testified that the results of their respective CAPM analyses underestimate a fair ROE for Gulf at this time, and therefore, recommend that we give little or no weight to their CAPM results. Witness Vander Weide concluded that the CAPM underestimates the ROE for companies such as his proxy companies with betas significantly less than 1.0, and recommended that we give little or no weight to his ROE estimates obtained from his CAPM analysis. Witness Woolridge testified that he relied primarily on the DCF model and gave less weight to the results of his CAPM study because he believed that the risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities. Witness Gorman testified that he was concerned with the low estimates produced by his CAPM analysis, and as such, he placed minimal weight on the results of his CAPM study in this proceeding. Based on the witnesses' testimony in this proceeding regarding the results obtained

[19] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944); and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
[20] See Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company, p. 24.

using the CAPM, in the interest of efficiency, we will not address the witnesses' arguments and testimony regarding the CAPM in this order. We want to be clear that it is not recommending rejecting the use of the CAPM as a generally accepted method to estimate the ROE, but in this case, the record supports assigning no weight to the witnesses' CAPM results for purposes of determining the appropriate ROE for Gulf.

DCF Model

All three Gulf witnesses relied on the results of their respective DCF models to arrive at their recommended returns on equity for the Company. Gulf witness Vander Weide obtained a result of 10.7 percent, OPC witness Woolridge obtained a result of 9.3 percent, and FEA witness Gorman obtained a result of 9.75 percent. The DCF model is based on the assumption that investors value an asset based on the present value of the future cash flows they expect to receive from the asset. The DCF model assumes that a company's stock price is equal to the value of all future dividends discounted back to the present at the required rate of return. The main differences in the results of the witnesses' DCF models is attributed to the mathematical form of the DCF model used, quarterly or annual, and the growth rate used in the model.

Proxy Group Selection

Gulf witness Vander Weide selected his proxy group from electric companies followed by Value Line that met the following criteria: (1) paid dividends during every quarter of the past two years and did not decrease its dividends during any quarter; (2) had at least three analysts included in the EPS growth forecasts reported from Thomson Reuters I/B/E/S; (3) had an investment grade bond rating; (4) had a Value Line Safety Rank of 1, 2, or 3, and (5) were not the subject of a merger offer that has not been completed. Based on this selection criteria, witness Vander Weide indentified 24 companies to include in his proxy group that he testified were similar in risk to Gulf.

OPC witness Woolridge selected his proxy group of companies from all the companies listed as electric utilities by Value Line Investment Survey and AUS Utilities Report that: (1) have at least 50 percent of its revenue from regulated electric operations; (2) have an investment grade bond rating; (3) pay a cash dividend; (4) have analysts' long-term growth forecasts available from Yahoo, Reuters, and Zacks, and (5) are not involved in any merger or acquisition activity in the past year.

Gulf argued that witness Woolridge used unreliable and inappropriate sources to select the companies in his proxy group. Witness Vander Weide disagreed with witness Woolridge's selection criteria because, in his opinion, the average investor does not rely on AUS Utility Reports. Witness Vander Weide also disagreed with witness Woolridge's criterion that a proxy company must have at least 50 percent of revenue from regulated electric utility service and cited that the Hope and Bluefield decisions do not require that a proxy company must have a specific percentage of revenue from electric utility service, only that it have similar risk.

FEA witness Gorman selected the same electric utilities for his proxy group relied on by Gulf witness Vander Weide, but eliminated Duke Energy, Progress Energy, and Nextera Energy from his proxy group because they were involved in merger and acquisition (M&A) activity.

Gulf DCF Model Application

Witness Vander Weide testified that he relied on the quarterly DCF model as opposed to the annual model because the companies in his proxy group all paid dividends quarterly and a quarterly DCF model best estimates the ROE for his proxy group. Witness Vander Weide obtained his estimated growth rate from the mean earnings per share (EPS) forecasts published by Thomson Reuters I/B/E/S as of December 2010, which represented three-to-five year forecasts of EPS growth by financial analysts working at Wall Street firms. Witness Vander Weide testified that he relied on Wall Street analysts' projections of future EPS growth rates rather than historical or retention growth rates because, "there is considerable empirical evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth." The simple average growth rate of his proxy group was 6 percent. Witness Vander Weide included a 5 percent allowance for flotation costs in his DCF calculations. The 5 percent allowance equates to an upward adjustment of 26 basis points to his ROE estimate. Witness Vander Weide's DCF analysis produced a market-weighted average of 10.7 percent and a simple average of 11.4 percent for his proxy group of electric companies.

In his rebuttal testimony, witness Vander Weide updated his DCF model using a proxy group of 32 companies. The simple average DCF model result decreased from 11.4 percent in his direct testimony to 10.7 percent in his rebuttal testimony. Witness Vander Weide agreed that the growth component of his DCF model decreased from 6.0 percent in his direct testimony to 5.5 percent in his rebuttal testimony. Witness Vander Weide also agreed that based on the decrease in growth rates, one could conclude that the analysts' EPS growth projections have decreased since the time he calculated his original DCF results in his direct testimony.

OPC witness Woolridge testified that witness Vander Weide's quarterly DCF Model approach compounds the quarterly dividend payment over the first year to compute the dividend yield. Witness Woolridge contended that this adjustment essentially reinvests the dividend payments back into the stream of cash flows and generates a compounding of the dividend payments, thus inflating the return to the investor. Witness Woolridge explained that the error in this approach assumes the investor receives the quarterly dividend payments and has the option to reinvest the proceeds. This reinvestment option generates its own compounding, but is not included in the actual dividend payments of the issuing company.

OPC's argument was corroborated by the academic text, New Regulatory Finance, by Roger A. Morin, PhD.[21] The text explained the result obtained from the quarterly model is an effective market-based rate of return that, although appropriate for unregulated companies, requires modification to reflect a nominal return for regulated companies because of the manner in which their revenue requirement is set. In the case of a projected test year for a growing utility, the equity balance at the end of the test year exceeds the equity balance at the beginning

[21] Roger A. Morin, New Regulatory Finance (Public Utilities Reports, Inc. 2006).

of the test year. Applying the effective return from the quarterly DCF model to the average annual equity balance will produce a higher actual effective return to the investor, and therefore, the use of the nominal return is preferable to the use of the effective return. Gulf witness Vander Weide disagreed that the quarterly DCF model produces an effective return that must be adjusted to a nominal return when determining the revenue requirement. Witness Vander Weide argued that the nominal return does not represent the ROE for Gulf which is determined by finding the discount rate which equates the present value of the cash flows to the market price. However, witness Vander Weide acknowledged that Gulf may be able to over earn or under earn its allowed cost of capital for a variety of reasons, including a change in the value of the rate base. Witness Vander Weide further stated that the only thing he could do was provide the best estimate of the ROE, and someone else can determine whether Gulf would be able to over or under earn in that regard.

Witness Woolridge contended that witness Vander Weide was in error by relying exclusively on the long-term EPS growth rate forecasts of Wall Street analysts in developing his DCF growth rate of 6.0 percent. Witness Woolridge cited numerous studies of analysts' earnings forecasts and testified that the studies almost unanimously concluded that analysts' earnings forecasts are overly optimistic. Specifically, witness Woolridge cited a study reported by *McKinsey on Finance* in the spring of 2010, entitled "Equity Analysts: Still too Bullish" whereby he testified the study indicated that even after a decade of stricter regulation to prevent investment bankers from pressuring analysts to provide favorable projections, analysts' long-term earnings forecasts continue to be excessively optimistic. Witness Woolridge testified that he conducted a similar study using electric utility companies and the results showed that during the twenty-year period 1988 through 2008, the average quarterly three-to-five year projected and actual EPS growth rates were 4.6 percent and 2.9 percent, respectively. Witness Woolridge concluded that, overall, the upward bias in EPS growth rate projections for electric utility companies is not as pronounced as it is for all companies, but is still upwardly-biased.

Witness Vander Weide disagreed with witness Woolridge that the quarterly DCF model allows investors to earn more than their required rate of ROE. Witness Vander Weide also disagreed with witness Woolridge's assertion that the appropriate dividend yield adjustment for growth in the DCF model, according to Dr. Myron Gordon, is the expected dividend for the next quarter multiplied by four. Witness Vander Weide contended that although Dr. Gordon was an early proponent of the DCF model, it does not imply that Dr. Gordon was correct is his arguments regarding the DCF model. He maintained that when dividends are paid quarterly, the quarterly DCF model must be used. Witness Vander Weide testified that the quarterly DCF model offers a better estimate of investors' required ROE than the annual DCF model, and whether a company earns more than its cost of equity depends on other external factors which cannot be known at the time the ROE is being estimated.

Witness Vander Weide also refuted witness Woolridge's criticism of his statistical studies of the relationship between analysts' growth forecasts and stock prices. Witness Vander Weide testified that his study was updated in 2004 and not outdated as claimed by witness Woolridge. Witness Vander Weide testified that the updated study continues to support his conclusion that the analysts' growth rates are more highly correlated with stock prices than historical measures such as those employed by witness Woolridge.

Witness Vander Weide further contended that witness Woolridge's claim that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased is incorrect. Witness Vander Weide testified that, to the contrary, the academic literature presents compelling evidence that analysts' EPS forecasts are unbiased. As support for his argument, witness Vander Weide identified eight published research studies that compare the accuracy of analysts' growth forecasts to the accuracy of forecasts based on historical data. He also identified seven studies that use regression techniques to test whether analysts' growth forecasts are good proxies for investor growth expectations, and cited nine articles that studied whether analysts' forecasts are biased toward optimism. However, during cross examination, OPC showed that the studies discussed in the nine articles relied upon by witness Vander Weide related to annual EPS growth and not three-to-five year growth rate forecasts. Based on the empirical evidence identified in his rebuttal testimony, witness Vander Weide concluded that analysts' EPS growth forecasts are not optimistic and are reasonable proxies for investor growth expectations, while the historical growth extrapolations and retention growth rates used by witness Woolridge are not. Witness Vander Weide contended that witness Woolridge failed to recognize that the DCF model requires the growth forecasts of investors, whether accurate or not.

FEA witness Gorman contended that the ROE result of 10.7 percent produced by witness Vander Weide's DCF analysis overstated the investor-required ROE because: (1) he used excessive and unreasonable growth estimates, and (2) he relied on a quarterly compounding DCF methodology. Witness Gorman testified that the constant growth DCF model used by witness Vander Weide requires an estimated long-term sustainable growth rate. Witness Gorman reasoned that because the growth rate used by witness Vander Weide in his DCF model (6.0 percent) exceeds the projected nominal growth rate of the U.S. Gross Domestic Product (GDP) (4.9 percent), witness Vander Weide's DCF result of 10.7 percent is inflated and should be rejected. Witness Gorman further testified that the quarterly compounding of the DCF model overstates a utility's ROE because it provides shareholders with an opportunity to earn the dividend reinvestment return twice. Witness Gorman explained that shareholders would earn the dividend reinvestment through a higher authorized ROE and through the actual receipt of the dividend and the reinvestment of the dividends throughout the year. Witness Gorman contended that the double counting of the dividend reinvestment return is not reasonable and will unjustly inflate Gulf's rates. Witness Gorman further testified that the quarterly compounding component of the return is not a cost to the utility and only Gulf's cost of common equity should be included in the authorized ROE.

Witness Vander Weide disagreed with witness Gorman's testimony that the use of a quarterly DCF model is inappropriate because the quarterly compounding component of the return is not a cost to the utility. Witness Vander Weide contended that the ROE is greater when the company makes four quarterly dividend payments than when it makes a single dividend payment at the end of the year because the quarterly payment of dividends requires the company to make dividend payments sooner on average than the annual payment, and sooner payments are always more costly than later payments.

OPC DCF Model Application

Witness Woolridge applied the DCF model to a proxy group of 28 electric companies that was similar to the proxy group used by Gulf witness Vander Weide. Witness Woolridge's DCF model produced a result of 9.3 percent. Witness Woolridge testified that he relied primarily on the DCF model to estimate the ROE and believed that the DCF model provided the best measure of equity cost rates for public utilities.

Witness Woolridge testified that the constant growth version of the DCF model is appropriate for estimating the ROE for utilities. This version can be expressed mathematically as the expected dividend yield in the coming year plus the expected growth rate of dividends. In his DCF model, witness Woolridge derived an expected dividend yield for his proxy group of 4.6 percent and added an expected growth rate of 4.75 percent to the dividend yield to obtain an equity cost rate of 9.3 percent.

To determine the dividend yield for his proxy group, witness Woolridge first obtained the dividend yields for each company in his proxy group from AUS Utility Reports for the period May 2011 through October 2011. Witness Woolridge then determined the median dividend yield for his proxy group for the six months ended October 2011 (4.5 percent) and for the month of October 2011 (4.4 percent). He then calculated the average of the median six-month dividend yield and the median October 2011 dividend yield to arrive at a dividend yield of 4.45 percent for his proxy group.

Witness Woolridge made an adjustment to the dividend yield to account for dividend growth in the coming year by multiplying the dividend yield by one-half of his expected growth rate. Witness Woolridge testified that it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate. Witness Woolridge explained that he used this approach because companies tend to increase their dividends at different times during the year and you don't know when a dividend increase is going to occur. Witness Woolridge also indicated that this is the same approach used by FERC in its application of the DCF model.

Witness Woolridge used 4.75 percent as the expected growth rate in his DCF model. Witness Woolridge testified that the primary problem and controversy in applying the DCF model entailed estimating investors' expected dividend growth rate. Witness Woolridge explained that investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential. To estimate his growth rate, witness Woolridge analyzed several measures of growth for his proxy group. Those measures included a review of: (1) historical and projected growth rate estimates for EPS, dividend per share (DPS), and book value per share (BVPS) as published by Value Line; (2) average 5-year EPS growth rate forecasts of Wall Street Analysts as published by Yahoo, Reuters, and Zacks, and (3) prospective earnings retention rates and earned returns on common equity. The results of witness Woolridge's analyses showed that the average of the projected and prospective growth indicators for his proxy group was 4.6 percent. Witness Woolridge testified that, giving more weight to the projected growth rates, an expected growth rate in the range of 4.5 to 5.0 percent is reasonable. He then chose the midpoint of the range, or 4.75 percent, as the growth rate in his DCF analysis.

Gulf argued that OPC's recommended ROE of 9.25 percent is based on a flawed application of the DCF model and should be rejected. Gulf argued that in his DCF model, witness Woolridge used: (1) unreliable and inappropriate sources to select the companies in his proxy group; (2) an annual version of the DCF model rather than a quarterly model; (3) historical and internal growth rates and not analysts' projected growth rates, and (4) mistakenly used zero percent instead of a 10 percent projected rate of return for Xcel Energy when calculating the average rate of return for his proxy group.

Witness Vander Weide contended that witness Woolridge incorrectly used an annual DCF model based on the assumption that companies pay dividends only at the end of each year. Witness Vander Weide explained that witness Woolridge should have used the quarterly DCF model since his proxy companies all pay dividends quarterly. Witness Vander Weide disagreed with witness Woolridge's application of the annual DCF model wherein he used one-half of the estimated growth rate as the first period growth rate. Witness Vander Weide contended that under witness Woolridge's assumption that dividends grow at the same constant rate forever, he should have applied the full estimated growth rate for his first period dividend.

Witness Vander Weide also disagreed with witness Woolridge's inclusion of historical growth rates and internal growth rates to estimate his proxy group's ROE. Witness Vander Weide contended that historical growth rates are inherently inferior to analysts' forecasts because analysts' forecasts already incorporate the historical growth rates in addition to current conditions and future expectations. Witness Vander Weide contended that the internal growth rate method is logically circular and requires an estimate of the expected rate of return on equity which is multiplied by the retention ratio. Witness Vander Weide testified that witness Woolridge's DCF model would have produced an average result of 10.3 percent if witness Woolridge used the quarterly DCF model, incorporated an allowance for flotation costs, and relied on analysts' growth forecasts to estimate the growth rate.

FEA DCF Model Application

Witness Gorman used three variations of the DCF model to estimate the appropriate ROE for Gulf: (1) a constant growth model using analysts' growth projections; (2) a constant growth model using sustainable growth estimates; and (3) a multi-stage model. Based on his DCF studies, witness Gorman found that a reasonable DCF return estimate is 9.75 percent.

In his constant growth model using analysts' growth estimates, witness Gorman relied on the average of the weekly high and low stock prices over a 13-week period ended September 13, 2011. For his dividend estimate, witness Gorman used the most recently paid quarterly dividend as reported by Value Line Investment Survey, multiplied by four, and adjusted for next year's growth. For the analysts' growth estimates, witness Gorman relied on the average of analysts' projected growth rates as published by Zacks, SNL Financial, and Reuters, on September 22, 2011. The average growth rate for his proxy group was 5.26 percent. Witness Gorman obtained an indicated average ROE of 10.5 percent from his constant growth DCF model. However, witness Gorman testified that he believed the three-to-five year growth rate estimated by analysts' exceeds a long-term sustainable growth rate that is required by the constant growth DCF model. Witness Gorman contended that utilities cannot sustain indefinitely a growth rate that exceeds the growth rate of the overall economy. Witness Gorman testified that the consensus of published economists projects that the U.S. GDP will grow at a rate of no more than 4.7 percent to 5.1 percent over the next five to ten years.

Witness Gorman also applied a constant growth DCF model using an estimated sustainable growth rate to his proxy group. This growth rate in this method was based on the percentage of a utility's earnings that are retained and not paid out in dividends. The earnings are typically reinvested in the utility's plant at the company's expected ROE. Witness Gorman relied on data from Value Line to estimate an average long-term sustainable growth rate of 4.66 percent for his proxy group. Witness Gorman used the same stock price and dividend data from his DCF model using analysts' growth estimates, but replaced the analysts' growth rate with the sustainable growth rate. Witness Gorman obtained an average result of 9.43 percent using a constant growth DCF model and an estimated sustainable growth rate.

Witness Gorman performed a multi-stage DCF analysis to reflect changing growth rate expectations over time. The multi-stage DCF model reflects three growth periods consisting of: (1) short-term growth for the first five years; (2) a transition period from year six to year ten, and (3) a long-term growth period starting in year eleven. Witness Gorman relied on the same stock price and dividend data he used in his constant growth DCF models. For the first stage short-term growth rate, witness Gorman used the same average analysts' growth rate of 5.26 percent he used in his constant growth DCF model. For the third stage long-term growth rate, witness Gorman relied on the midpoint (4.9 percent) of the consensus economists' projected average five-year (5.1 percent) and ten-year (4.7 percent) GDP growth rates as published by Blue Chip Economic Indicators on March 10, 2011. For the second stage transition period, witness Gorman either increased or decreased the growth rate by an equal amount each year to reflect the difference between the first stage growth rate and the third stage growth rate. The results of witness Gorman's multi-stage DCF analysis indicated an ROE of 9.78 percent.

Gulf argued that witness Gorman's DCF model contained flaws similar to those of witness Woolridge's DCF model and should be rejected. Gulf's witness Vander Weide disagreed with witness Gorman's use of the annual DCF model to estimate Gulf's ROE since all of the companies in his proxy group pay dividends quarterly. Witness Vander Weide also disagreed with witness Gorman's exclusion of the allowance for flotation costs in his DCF model. Witness Vander Weide also objected to witness Gorman's use of a sustainable growth method to estimate the growth rate because analysts' growth forecasts are a better proxy for investors' growth expectations, and sustainable growth methods are logically circular regarding the rate of return.

Witness Vander Weide contended that witness Gorman's three-stage DCF model is based on the assumption that investors growth expectations follow the growth rates in his three-stage DCF model. Witness Vander Weide argued that witness Gorman simply assumes that rational investors would make this assumption. Witness Vander Weide agreed with witness Gorman that a company cannot grow at a rate in excess of the rate of growth of the U.S. economy indefinitely, and reasoned that if so, the company would eventually take over the economy. However, witness Vander Weide testified that witness Gorman failed to recognize that companies do not have to grow at the same rate forever for the single-stage DCF model to be a reasonable return on equity estimation methodology.

Witness Vander Weide also disagreed with witness Gorman that investors' growth expectations have to be rational. Witness Vander Weide pointed out that in hindsight, most economists would agree that investors' growth expectations during the tech stock boom of the late 1990s and early 2000 were irrational. Witness Vander Weide contended that the DCF model requires the use of investors' growth expectations, whether rational or irrational. Witness Vander Weide testified that witness Gorman obtained a result of 10.1 percent from his DCF analysis when using analysts' growth forecasts.

Risk Premium Model

In addition to the DCF model, Gulf witness Vander Weide and FEA witness Gorman both used risk premium approaches to estimate the ROE for Gulf. OPC witness Woolridge did not perform a stand-alone risk premium analysis in his testimony.

Gulf Risk Premium Model

Gulf witness Vander Weide used two versions of the risk premium approach to estimate the required risk premium on an equity investment in Gulf. His ex ante risk premium approach produced a result of 11.0 percent and his ex post risk premium approach produced a result of 10.8 percent.

In his ex ante risk premium approach, witness Vander Weide applied his quarterly DCF model to the Moody's group of 24 electric companies for each month from September 1999 through December 2010. He compared the results of his DCF analysis to the concurrent interest rate on Moody's A-rated utility bonds. Witness Vander Weide then performed a regression analysis on this comparison to derive an estimated risk premium of 4.9 percent. He then estimated a forecasted yield to maturity on A-rated utility bonds of 6.15 percent. Witness Vander Weide then added his estimated risk premium of 4.9 percent to his forecasted yield to maturity on A-rated utility bonds of 6.15 percent to arrive at an ROE estimate of 11.0 percent.

In his ex post risk premium approach, witness Vander Weide performed two studies of the comparable historical earned returns for an investment in a portfolio of stocks and the yield on Moody's A-rated Utility Bonds during the 73 year period from 1937 through 2010. In his first study, witness Vander Weide compared the return on the S&P 500 to the return on the Moody's A-rated Utility Bonds. The average annual return on an investment in the S&P 500 portfolio was 11.06 and the average annual return on an investment in Moody's A-rated Utility Bond portfolio was 6.42. Witness Vander Weide concluded that the risk premium on the S&P 500 stock portfolio was 4.64 percent. Witness Vander Weide performed a second ex post risk premium study using the S&P Utility Stock Index instead of the S&P 500. The average annual return on an investment in the S&P Utility Stock Index was 10.5 percent which exceeded the return on an investment in Moody's A-rated Utility Bond portfolio by 4.1 percent. Based on these results, witness Vander Weide concluded that equity investors today require a risk premium of approximately 4.1 to 4.6 percentage points above the expected yield on A-rated utility bonds of 6.15 percent. By adding the risk premium to the assumed yield on A-rated utility bonds, witness Vander Weide obtained an expected ROE in the range of 10.2 percent to 10.8 percent with a midpoint of 10.5 percent. Witness Vander Weide added a 26 basis point allowance for flotation costs to his midpoint estimate of 10.5 percent to obtain a result of 10.8 percent for his ex post risk premium ROE.

OPC argued that witness Vander Weide selected inputs to his ex post and ex ante risk premium studies that imparted an upward bias to the results. OPC contended that when calculating the risk premium in his analysis, witness Vander Weide again used Wall Street analysts' projections exclusively and obtained an overall return on the market of 13.3 percent which OPC believed to be unrealistic.

OPC witness Woolridge testified that witness Vander Weide made errors in his RP analysis that included: (1) an inflated base interest rate; (2) excessive risk premiums, and (3) the inclusion of flotation costs. Witness Woolridge contended witness Vander Weide's projected yield on A-rated utility bonds of 6.15 percent is well above the current market rate, which is 4.5 percent. In addition, he contended that witness Vander Weide's use of A-rated utility bonds is subject to credit risk since they are not default risk-free like U.S. Treasury bonds. Witness Woolridge also contended that witness Vander Weide's DCF-based ex ante risk premium approach used the same DCF methodology employed in his stand-alone DCF model, and therefore, produced an inflated estimate of the risk premium. Witness Woolridge further testified that there are a number of inherent flaws in witness Vander Weide's ex post risk premium analysis which relies on historical returns to estimate expected equity risk premiums. Measuring the equity risk premium based on historical stock and bond returns is subject to substantial forecasting errors.

Witness Vander Weide disagreed with witness Woolridge's criticism of his use of A-rated bond yields as the interest rate component in his risk premium analysis. Witness Vander Weide contended that the risk premium approach does not require that the interest rate be risk-free. Witness Vander Weide testified the only requirement of the risk premium approach is that the same interest rate used to estimate the interest rate component be used to estimate the risk premium component. Witness Vander Weide explained the interest rate derived from A-rated utility bonds is higher than the interest rate derived from government bonds, but the higher interest rate is offset by a lower risk premium. The lower risk premium arises because the spread between the ROE and yield on A-rated bonds is lower than the spread between the ROE and the yield on long-term government bonds.

FEA RP Model

FEA's witness Gorman's risk premium analyses produced an ROE estimate in the range of 9.60 percent to 9.90 percent, with a midpoint estimate of approximately 9.75 percent. Witness Gorman based his risk premium analysis on two estimates of an equity risk premium over the 26-year period 1986 through the second quarter 2011. In both models, witness Gorman based the common equity required returns on the average authorized returns on common equity for electric utilities as reported by Regulatory Research Associates, Inc.

Witness Gorman's first risk premium estimate was based on the difference between the required return on utility common equity investments and U.S. Treasury bonds. Witness Gorman relied on Blue Chip Financial Forecasts, published on September 1, 2011, for the projected 30-year Treasury bond yield. The average indicated equity risk premium over U.S. Treasury bond yields has been 5.21 percent with a range of 4.40 percent to 6.09 percent. Witness Gorman added the projected 30-year Treasury bond yield of 4.2 percent to his risk premium result to obtain an indicated return on equity in the range of 8.60 percent to 10.29 percent. Witness Gorman testified that he believes an estimated range of risk premiums provides the best method to measure the current return on common equity using the risk premium methodology. Witness Gorman explained that because there is a very large difference between current (3.88 percent) and projected (4.20 percent) Treasury bond rates, he recommended an equity risk premium between the midpoint and maximum of his range, or 9.90 percent.

Witness Gorman based his second risk premium estimate on the spread between regulatory commission authorized returns on common equity and A-rated utility bonds. Witness Gorman testified that the average indicated equity risk premium was 3.79 percent with a range of 3.03 percent to 4.62 percent. Witness Gorman relied on the 13-week average yield on Baa-rated utility bonds for the period ended September 16, 2011, as reported by Moodys.com, to estimate his base interest rate of 5.36 percent. Witness Gorman then added the risk premium estimate to the base interest rate and obtained a result in the range of 8.39 percent to 9.98 percent. Recognizing the current low bond yields, witness Gorman recommended a return on equity of 9.60 percent.

Witness Vander Weide disagreed with witness Gorman's method of estimating the required risk premium. He contended that because witness Gorman relied on the average authorized returns for other utilities, he failed to recognize that we have a responsibility to make an independent assessment of the required ROE for Gulf. Further, witness Vander Weide testified that witness Gorman failed to recognize that the indicated risk premium in his data tends to increase as interest rates decline. Witness Vander Weide contended that witness Gorman should have adjusted his result to account for the relationship between the allowed risk premium on equity and the yield on A-rated utility bonds and Treasury bonds. Witness Vander Weide testified that if witness Gorman had used Value Line's forecasted 4.9 percent yield on long-term Treasury bonds and a forecasted yield of 5.89 percent on A-rated utility bonds, he would have obtained a risk premium of 6.06 percent over Treasury bonds and 4.48 percent over utility bonds. Witness Vander Weide concluded that if witness Gorman had used these risk premium estimates, he would have obtained an indicated ROE for Gulf in the range of 10.5 percent to 10.7 percent.

Witness Vander Weide also addressed witness Gorman's objection to his use of a forecasted interest rate, rather than a current interest rate in his risk premium analysis. Witness Vander Weide explained that he used a forecasted interest rate because a fair rate of return standard requires that Gulf have an opportunity to earn its ROE during the period when rates are in effect, and the rates in this case will not come into effect until some time in 2012. Witness Vander Weide refuted witness Gorman's claim that his ex ante risk premium analysis would have produced an indicated ROE equal to 9.82 percent if he used the current interest rate on A-rated utility bonds equal to 4.92 percent. Witness Vander Weide contended that if witness

Gorman had used the current interest rate of 4.92 percent in his ex ante risk premium analysis, the resulting risk premium would have been 5.57 percent which would have indicated a ROE equal to 10.47 percent, not the 9.82 percent calculated by witness Gorman.

Gulf Flotation Cost Adjustment

Gulf witness Vander Weide applied an upward adjustment of 26 basis points to the results of each of his models to account for flotation costs associated with obtaining equity capital. Witness Vander Weide explained that all firms that have sold securities in the capital markets have incurred some level of flotation costs and those costs must be recovered over the life of the equity issue.

Witness Woolridge testified that witness Vander Weide's upward adjustment to the return on equity for flotation costs is erroneous. Witness Woolridge contended that witness Vander Weide has not identified any actual flotation costs for Gulf, and those costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. Witness Woolridge testified that flotation costs, in the form of the underwriting spread, represent the difference between the price paid by investors and the amount received by the issuing company, and hence, these are not expenses that must be recovered through the regulatory process.

Witness Gorman testified that witness Vander Weide's flotation cost adjustment is not based on Gulf's actual common stock flotation cost and should therefore be rejected. Witness Gorman contended that witness Vander Weide derived his flotation cost adjustment based on published academic literature. Witness Gorman reasoned that because witness Vander Weide does not show that his adjustment is based on Gulf's actual and verifiable flotation expenses, there simply are no means of verifying whether witness Vander Weide's proposal is reasonable or appropriate.

Witness Vander Weide disagreed with witness Woolridge's assertion that Gulf did not provide any evidence it incurs flotation costs when it issues new equity. Witness Vander Weide explained that although Gulf does not issue equity in the capital markets, Southern Company must issue equity to provide financing to Gulf to make investments in its electric utility operations in Florida. Witness Vander Weide reasoned that if Southern Company is not able to recover its flotation costs through Gulf's rates, it will not be able to recover the full cost of issuing equity invested in Gulf.

Gulf Financial Leverage Adjustment

Witness Vander Weide testified that the ROE for his proxy company group depends on the companies' financial risk, which is measured by the market values of debt and equity in their capital structures. Witness Vander Weide testified that the financial risk of Gulf as reflected in its rate making capital structure is greater than the financial risk embodied in the ROE estimates for his proxy group. Gulf's rate making capital structure contains 46 percent common equity and the average market value capital structure for his proxy group contains 55 percent common equity. Therefore, witness Vander Weide reasoned that the ROE for his proxy group must be adjusted to reflect the higher financial risk associated with Gulf's rate making capital structure as compared to the average market-value capital structure of his proxy group.

Witness Vander Weide contended that one must adjust the indicated ROE for his proxy group upward in order for investors to have an opportunity to earn a return on their investment in Gulf that is commensurate with returns they could earn on other investments of comparable risk. Witness Vander Weide made an upward adjustment of 90 basis points to the indicated ROE for Gulf so that mathematically the weighted average cost of capital for Gulf is equal to that of his proxy group. Making this adjustment resulted in witness Vander Weide's recommended ROE for Gulf of 11.7 percent.

Gulf asserted that the market value of equity was determined by multiplying the stock price by the number of common equity shares outstanding. Witness Vander Weide agreed that the stock price reflects the risks associated with the security as perceived by informed investors, and those investors understand that the traditional rate base - rate of return form of regulation used by us is applied to the book value of the assets. Gulf asserted that because the market value and book value of debt are generally similar, analysts typically use the book value of debt as a proxy for the market value of debt. Witness Vander Weide was asked several times to compare Gulf's rate making capital structure to the equivalent book value capital structures of the companies in his proxy group but declined to do so. Witness Vander Weide argued that the book value capital structure is not relevant for the purpose of estimating the cost of equity because the cost of equity does not reflect the book value capital structures, it reflects the market value capital structures.

OPC argued that there was no basis for witness Vander Weide's upward financial leverage adjustment of 90 basis points. OPC argued that investors are aware of both book value-based and market value-based capital structures and the different uses made of them. OPC contended that investors assess all risks associated with a security, regardless of how financial risk is measured, and those perceptions are reflected in the price they are willing to pay for the stock. OPC argued that we should reject witness Vander Weide's rationale and the adjustment that accompanied it.

Witness Woolridge testified that witness Vander Weide's leverage adjustment of 90 basis points is unwarranted because the market value of Gulf's equity exceeds the book value which indicates the Company is earning an ROE in excess of its cost of equity. Witness Woolridge testified that a firm that earns an ROE above its cost of equity will see its common stock sell at a price above its book value, and conversely, a firm that earns an ROE below its cost of equity will see its common stock sell at a price below its book value. To assess the relationship by industry, witness Woolridge performed a regression study between the estimated ROE and market-to-book ratios using gas distribution, electric utility and water utility companies. Witness Woolridge concluded that the results of his study demonstrate that there is a strong relationship between returns on equity and the market-to-book ratios for public utilities. Hence, witness Woolridge contended that for a utility with a relatively high market-to-book ratio and ROE, the leverage adjustment will increase the estimated equity cost rate. Witness Woolridge further testified that Gulf's financial statements and fixed financial obligations remain the same, and thus, there is no need for a leverage adjustment because there is no change in leverage. Witness Woolridge also testified that financial publications and investment firms report capitalizations on a book value and not a market value basis. Finally, witness Woolridge contended that witness Vander Weide's leverage adjustment has not been accepted by regulatory commissions because it increases the ROE for utilities that have high returns on common equity and decreases the ROE for utilities that have low returns on common equity.

Witness Gorman testified that witness Vander Weide's leverage adjustment is without merit and should be rejected. Witness Gorman contended that the implicit premise of witness Vander Weide's leverage adjustment is that book value capitalization is measured differently than market value capitalization. Witness Gorman contended that Gulf's financial risk is tied to its book value capitalization which in turn drives its market value capitalization, and therefore, are not separate factors. Witness Gorman contended that a utility's financial risk relates to its ability to generate the internal cash flows necessary to meet its financial obligations. Witness Gorman testified that these internal cash flows drive stock valuations which produce the market capitalization structure. Witness Gorman explained that book value leverage represents the utility's contractual obligations to pay debt interest and principal payments, and therefore, best describes the financial obligations in relation to the cash flows produced.

Witness Gorman further testified that witness Vander Weide's leverage adjustment is nothing more than a flawed market-to-book ratio adjustment which would produce an excessive return on incremental utility plant investments. Witness Gorman explained that if Gulf were to repurchase its own stock, it would expect to earn a market-based return of 10.8 percent based on witness Vander Weide's recommended ROE results. However, witness Gorman explained, if we accepted witness Vander Weide's leverage adjusted ROE, Gulf could earn a return of 11.7 percent on incremental utility plant investments. Witness Gorman contended that under witness Vander Weide's proposal, Gulf would be encouraged to gold-plate utility plant investment because it would be provided with an above-market risk adjusted return on such investments. Witness Gorman concluded that providing Gulf with an incentive to earn more than a fair risk adjusted return on utility plant investments would result in rates not being just and reasonable.

Witness Vander Weide testified that witness Woolridge's regression analysis for his electric utilities does not support his claim that a market-to-book ratio above 1.0 indicates that a company is earning more than its cost of equity. Witness Vander Weide testified that of the 54 electric utilities in witness Woolridge's market-to-book study, 25 have returns on equity less than 9.25 percent, and only seven of those 25 companies have market-to-book ratios less than 1.0. The average ROE for the 25 companies is 7.1 percent and their average market-to-book ratio is 1.23. Witness Vander Weide contended that the data contradicts witness Woolridge's claim. Witness Vander Weide testified that he updated witness Woolridge's study using current Value Line data as of October 2011. He found that of the 53 electric utilities followed by Value Line, 19 have returns on equity below 9.25 percent and only four of the utilities have market-to-book ratios less than 1.0. Witness Vander Weide concluded that the data provided evidence that witness Woolridge's hypothesis regarding the relationship between returns on equity and market-to-book ratios is incorrect.

Witness Vander Weide disagreed with witness Woolridge's criticism of his financial leverage adjustment. He disagreed that his financial risk adjustment assumes a change in Gulf's capital structure as expressed by witness Woolridge. Witness Vander Weide testified that the observation that financial publications report capitalization on a book value basis, as testified to by witness Woolridge, does not undermine the validity of his financial risk adjustment. Witness Vander Weide testified that he did not state, as witness Woolridge claimed, that he could not indentify any proceeding in which he testified wherein the regulatory commission adopted his leverage adjustment. Witness Vander Weide clarified his statement that he does not maintain records of regulatory decisions or a list of all cases in which commissions have accepted his recommendations. Witness Vander Weide reiterated that he was generally aware that financial adjustments similar to that which he proposed have been adopted in Pennsylvania and Canada, and that many states use market value structures to determine utility property taxes.

Witness Vander Weide reiterated that he made an upward adjustment of 90 basis points to the results of his ROE analysis for his proxy group of companies to reflect the average difference between the financial risk of his proxy group as measured by market value capital structure and the financial risk reflected in Gulf's recommended book value capital structure. Witness Vander Weide disagreed with witness Gorman's definition of financial risk and contended that witness Gorman's definition reflects the viewpoint of debt investors, not the viewpoint of equity investors. Witness Vander Weide testified that debt investors are concerned with a company's ability to cover the interest and principal payments on its debt, while equity investors are primarily concerned with the forward-looking variance of return on their investment. Witness Vander Weide contended that the forward-looking variance of return on investment depends on a company's market value capital structure, not its book value capital structure. Witness Vander Weide contended that the equity investors' point of view is the only one that is relevant for determining the return on equity.

Gulf witness Vilbert responded to the testimony of witnesses Woolridge and Gorman regarding the measurement of financial leverage and its impact on a regulated utility's allowed ROE. Witness Vilbert testified that the disregard of market value capitalization in measuring a company's financial leverage and risk is a fundamental flaw in witnesses Woolridge's and Gorman's testimony. Witness Vilbert testified that witnesses Woolridge and Gorman made an incorrect assertion when they claimed that no leverage adjustment is needed because financial risks are properly measured by the book value capital structure. Witness Vilbert contended that the notion that financial leverage is and should be measured on a market value basis is supported in every textbook on corporate finance of which he is aware. Witness Vilbert testified that even witness Woolridge's text, Applied Principles of Finance, uses market values to illustrate the computation of the overall cost of capital.

Witness Vilbert testified that, based on the financial leverage theorems on the relationship between the ROE and financial leverage developed by Franco Modigliani and Merton Miller, financial leverage does not increase the market value to a firm as long as different combinations of debt and equity can be selected by the investors themselves. Witness Vilbert explained that to implement this financial construct, investors have to be able to buy and sell debt and equity at market prices to achieve their desired combination. Witness Vilbert also testified that economists generally prefer to use market values rather than historical values because market values convey timely information about the assets.

Witness Vilbert criticized witness Gorman's claim that financial leverage is measured by the sufficiency of the firm's operating cash flows to meet the contractual book value obligations. He agreed that a firm's debt obligations are typically defined in book value terms, and a firm's cash flows are their primary source of debt repayment, but explained that the market value of the firm is also a key determinant of a firm's debt capacity and borrowing cost. Witness Vilbert disagreed with witness Woolridge that market values in excess of book values indicates a company is earning an ROE greater than its cost of equity. Witness Vilbert agreed that, all else being equal, mathematically, a higher ROE gives rise to a higher market value of equity, and a higher market to book ratio. However, witness Vilbert contended that all else is not equal in real life. Witness Vilbert testified that witness Woolridge provided very little information on how he created his statistical analysis in his testimony and exhibits, that graphically showed a positive correlation between a utility's estimated ROE and its market-to-book ratio. Witness Vilbert contended that statistically, correlation does not necessarily mean a cause-and-effect relationship, and the empirical evidence to support witness Wooldridge's contention falls short. Witness Vilbert testified that due to flaws in witness Wooldridge's statistical assumptions, the positive correlation simply shows that the price to earnings ratio is positive for the utility companies.

Witness Vilbert contended that the results of witness Woolridge's analysis did not support his contention that above-market returns on equity, and no other factors, contribute to the utilities' market value exceeding book value. Witness Vilbert testified that some of the factors not considered by witness Wooldridge were: (1) some of the companies used in his regression analysis have unregulated lines of business that may have higher growth opportunities; (2) the utilities are subject to an allowed ROE and actual returns depend on external factors such as consumer demand, supply shocks, weather, etc.; (3) investor demand for safe haven investment could also increase the market-to-book ratios for utilities, and (4) estimated accounting returns could be affected by rate freezes, regulatory lag, and adjustments to rate components such as depreciation.

Financial Integrity

FEA witness Gorman testified that an authorized ROE of 9.75 percent will support internal cash flows that will be adequate to maintain Gulf's current investment grade bond rating. Witness Gorman reached his conclusion by comparing the key credit rating financial ratios for Gulf at its proposed capital structure, with a 9.75 percent ROE to Standard and Poor's (S&P) benchmark financial ratios using S&P's new credit metric ranges. Witness Gorman testified that by performing this analysis he was attempting to determine whether the rate of return and cash flow generation opportunity reflected in his proposed rate of return for Gulf will support target investment grade bond ratings and Gulf's financial integrity. Witness Gorman testified that Gulf currently has an "A" corporate bond rating from S&P. Witness Gorman testified that, "At my recommended return on equity and Gulf Power's proposed capital structure, the Company's financial credit metrics are supportive of its current investment grade bond rating."

Gulf witness Teel testified that the ROE of 9.75 percent recommended by FEA witness Gorman is not supportive of Gulf's credit ratings. Witness Teel contended that witness Gorman's conclusion that 9.75 percent would allow Gulf to maintain its current investment grade bond rating is wrong. Witness Teel testified that the lower threshold for an investment grade rating are BBB- for S&P and Fitch, and Baa3 for Moody's. Witness Teel testified that S&P rates Gulf's long-term debt as A, while Fitch and Moody's ratings are A and A3, respectively. Witness Teel testified that Gulf targets A ratings by S&P and Fitch, and A2 by Moody's for its long-term debt. Witness Teel testified that witness Gorman used bond ratings below that of Gulf's current bond rating as the basis for his analysis, and his analysis was too limited to reach any conclusions regarding the effect a 9.75 percent ROE would have on Gulf's credit ratings. Witness Teel contended that witness Gorman's evaluation was limited to only one of three credit rating agencies (S&P) and did not consider the qualitative factors, such as the agencies' assessment of the regulatory environment in Florida, which are key drivers of a utility's credit ratings. Witness Teel testified that an authorized rate of return below the return required by investors would increase the concerns of the rating agencies about the regulatory environment in Florida.

Witness Gorman acknowledged that S&P used to have a very detailed matrix of credit rating metrics that assigned business risk and bond ratings as BBB, A, and AA, but that S&P changed its credit metric calculations about five years ago. Witness Gorman acknowledged as much by stating, "So unfortunately when they [S&P] did that, it's not as direct to be able to state that the credit metrics at this range with this business risk corresponds with either a BBB or a single A bond rating because the metrics themselves are not that transparent any longer."

<u>Average Authorized Returns</u>

At the hearing, witness Vander Weide proffered a list of the authorized returns on equity awarded by state regulatory authorities to integrated electric utility companies throughout the country during 2011 as reported by SNL Financial. The document showed that the authorized returns on equity ranged from a low of 9.8 percent to a high of 12.3 percent and averaged 10.4 percent for the group. However, witness Gorman testified that the average was skewed upward due to the 12.3 percent ROE awarded to Virginia Electric Power Company (VEPCO). Witness Gorman testified that the 12.3 percent ROE was dedicated to a specific generating facility only, not the overall integrated utility company. If the 12.3 percent ROE awarded to VEPCO was removed from the group, the average authorized ROE for 2011 would be about 10.1 percent. Witness Gorman acknowledged his recommended ROE of 9.75 percent was less than the industry average in 2011. Excluding the two VEPCO decisions related to the specific generating plants, witness Vander Weide's recommended 11.7 percent ROE would be the highest allowed ROE authorized in 2011.

<u>Conclusion</u>

The witnesses' recommended returns on equity suggest the appropriate authorized ROE for Gulf is within the range of 9.25 percent to 11.7 percent. Based on a review of the testimony and evidence regarding the witnesses' models presented in this proceeding, we find that the record supports an ROE for Gulf in the range of 9.75 percent to 10.75 percent.

Each witness relied heavily on the results of their respective DCF models to arrive at their recommended ROE for Gulf. The results of the witnesses' DCF analyses produced a range of 9.3 percent to 10.7 percent. The primary reasons for the differences in the witnesses' DCF model results relate to the version of model used, and the growth rate included in the DCF model. As discussed above, each witness testified to the merits of their own analysis and the flaws of their counter-party's analyses. Recognizing that the top end of the range represents results from a quarterly compounded DCF model based exclusively on Wall Street analysts' EPS growth forecasts, 10.7 percent is a high estimate of the investor-required return. Conversely, the bottom end of the range is a low estimate based on an annual DCF model that relied on an average of historical and projected growth rates for EPS, dividends per share, and an internal growth rate based on retained earnings.

Academic studies and other empirical research have shown that risk premium models based on historical earned returns are poor predictors of current market expectations. Consequently, we have reservations regarding the reliability of the results of the witnesses' ex post risk premium studies. We note that witness Vander Weide's risk premium of 4.9 percent used in his ex ante risk premium model is not significantly greater than the 4.62 percent risk premium witness Gorman used in his ex ante risk premium model. Witness Gorman's ex ante RP result was 9.75 percent and witness Vander Weide's was 11.0 percent. Witness Vander Weide revised his result to 10.9 percent using more recent projections. We concur with witnesses Woolridge and Gorman that the projected yield on A-rated utility bonds of 6.15 percent used in witness Vander Weide's ex ante RP analysis is unreasonably high based on more recent bond yield projections.

While it has been our practice to recognize an adjustment for flotation costs in certain applications, such as the leverage formula for water utilities, the evidence in the record does not support a specific allowance for flotation costs that should be added to the ROE. However, we recognize that there are costs incurred when a firm issues equity and those costs should be recovered within the ROE. In this context, the debate over whether to include or not include an allowance for flotation costs is similar to the debate over whether to use an annual or quarterly DCF model or a composite growth rate or an earnings-only growth rate in the DCF analysis. Our decision in this proceeding does not recognize a specific adjustment for flotation costs but takes into consideration the witnesses' testimony and analyses regarding an allowance for flotation costs.

We find that witness Vander Weide's proposed 90 basis point leverage adjustment to his estimated ROE is not appropriate. The mixing of market value and book value capitalization ratios in the formula is flawed. Witness Vander Weide acknowledged that Gulf's book value capital structure was appropriate for ratemaking purposes. In addition, he was asked several times to make a comparison of Gulf's ratemaking capital structure to the equivalent book value capital structures of the companies in his proxy group but declined to do so. Although witness Vander Weide testified that his leverage adjustment was accepted in part in an order issued March 10, 2005, by the Missouri Public Service Commission, subsequent orders by the same Commission rejected the methodology. The record showed that witness Vander Weide was unable to identify any other Commission decisions involving an electric utility that had recognized his leverage adjustment.

Due to the reliance on historical earned returns to estimate the current risk premium in the ex post RP models, concerns over the exclusive reliance on Wall Street analysts' EPS growth rates in the DCF analysis, use of a quarterly DCF model without an adjustment to recognize the difference between the effective and nominal rate of return, and the decision to recognize an inappropriately quantified leverage adjustment, we find that Gulf's requested ROE of 11.7 percent overstates the current investor-required ROE for Gulf. Conversely, OPC's recommended ROE of 9.25 percent may understate Gulf's required rate of return because Gulf's most recent issuance of long-term debt was completed at an effective cost rate of 5.75 percent and OPC witness Woolridge testified that academic studies indicate the forward-looking risk premium is between 4 percent and 5 percent.

Finally, the record indicated that the authorized ROEs set during 2011 for integrated electric utilities as reported by SNL Financial ranged from a low of 9.8 percent to a high of 11.35 percent and averaged 10.1 percent. While a 10.25 ROE for Gulf is based upon an independent assessment of the testimony and evidence in the record, the authorized ROEs from Commissions in other jurisdictions serve as a gauge to test the reasonableness of this ROE for Gulf.

Based on our review of the record, we find that an authorized ROE of 10.25 percent with a range of plus or minus 100 basis points, is appropriate. In arriving at this return, we have identified and weighed the strengths and weaknesses associated with the respective witnesses' analyses and also taken into account Gulf's need to continue to access the capital markets under reasonable terms. Moreover, we find that, at an equity ratio of 46 percent, an authorized ROE of 10.25 percent is supported by competent, substantial evidence in the record and satisfies the standards set forth in the Hope and Bluefield decisions of the U.S. Supreme Court regarding a fair and reasonable return for the provision of regulated service.

Weighted Average Cost of Capital

Based upon our decisions above and the proper components, amounts, and cost rates associated with the capital structure, we calculated a weighted average cost of capital of 6.39 percent. The capital structure has been reconciled to rate base pro rata over all sources of capital.

As discussed above, the appropriate balance of ADITs is $256,674,530. We find that the appropriate amount and cost rate of unamortized ITCs are $2,924,176 and 7.66 percent, respectively. We further find that the appropriate cost rate rates for long-term debt at 5.26 percent, short-term debt at 0.13 percent, and preferred stock at 6.39 percent. As discussed *supra*, 10.25 percent as the appropriate mid-point return on common equity.

The net effect of these adjustments is a decrease in the overall cost of capital from the 7.05 percent return requested by Gulf to a return of 6.39 percent as discussed herein. Schedule 2 shows the test year capital structure. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ending December 31, 2012, we find that the appropriate weighted average cost of capital for Gulf for purposes of setting rates in this proceeding is 6.39 percent.

VIII. NET OPERATING INCOME

Non-Regulated Affiliates

Gulf witness McMillan testified that Southern Company Services (SCS) is a subsidiary of the Southern Company, and an affiliate to Gulf, which provides services at-cost to Southern Company and its other subsidiaries. Gulf is a subsidiary of the Southern Company and receives professional and technical services from SCS, such as general design and engineering for transmission and generation; system operations for the generating fleet and transmission grid; and various corporate services and support in areas such as accounting, supply chain management, finance, treasury, human resources, information technology, and wireless communications.

Gulf argued the services SCS provides to Gulf would normally be performed by Gulf's employees. By using the services of the affiliate company, SCS, which are provided at-cost, Gulf is able to augment its personnel in specialized areas which provides Gulf the advantages of a stable utility workforce and economies of scale associated with specialized employees serving a larger organization. Gulf argued that if additional employees were hired instead of relying on SCS employee time or employee time of another operating company, Gulf's costs would be higher.

Witness McMillan argued that Gulf and its customers receive several benefits from the services provided by SCS. Gulf is a smaller operating company and SCS provides Gulf access to shared resources, which enables Gulf to avoid duplication of personnel and to utilize the talent of a centralized pool of professionals on an ongoing basis. He asserted that the Company and its customers also benefit from the services received from SCS through cost savings due to economies of scale and access to highly trained professionals that would be difficult to replicate at the Company level. Witness McMillan testified that SCS provides technical and professional services and costs are allocated based on the service provided and the most cost causative type allocator identified for that type of service. He added, Gulf has personnel that helps with hiring and personnel activities, but services are not duplicated.

Furthermore, witness McMillan contended Rule 25-6.1351(3), F.A.C., cited by OPC witness Dismukes that addresses transactions with affiliates, does not apply to services provided by SCS to Gulf because SCS exists solely to provide services to the Southern Company corporate family. Also, the Rule does not apply to services provided between Gulf and its regulated affiliates.[22] In addition, Gulf provided explanations and documentation that show how affiliate costs were allocated for years 2007 through June 30, 2011 and explained why certain revenues and expenses increased and decreased during these years.

Gulf witness Teel pointed out that OPC witness Dismukes' testimony may be interpreted to state that Southern Company's non-regulated affiliates receive benefits to their credit ratings

[22] Southern Company is comprised of four regulated utility companies: Gulf Power, Alabama Power, Georgia Power, and Mississippi Power according to information provided in Response to OPC Document Request 24 and Southern Company Services, Inc. 2010 FERC Form 60.

from association with the regulated operating companies. However, he testified that Southern Power Company (SPC) is the only non-regulated affiliate of the Southern Company that is rated by the credit rating agencies, and neither the Southern Company nor its subsidiaries are incorporated into the rating of SPC.

Gulf witness Deason addressed OPC witness Dismukes' contention that a 2 percent compensation payment in the amount of $1.5 million should be assessed the non-regulated companies to compensate the regulated companies for intangible benefits they receive, at no cost, through their affiliation with the regulated companies. He asserted that such payment would be imputed and Gulf would not actually receive revenue because imputed revenue is not real payments but an amount used for regulatory purposes to assign a benefit from one company to another. Witness Deason, however, stated that the imputed revenue would result in Gulf having less actual revenue per year to pay its actual expenses or to invest in infrastructure to serve its customers.

Witness Deason argued the financial implications would be real and the Company's actual achieved ROE and its interest coverage would decline and the Company would have to go to the capital markets to cover its short term cash needs. He asserted that the real effect of OPC witness Dismukes' recommendation would result in reduced customer rates simply because the Southern Company investments in the non-regulated markets have created additional revenues for the Southern Company.

In opposition to OPC witness Dismukes' recommendation, witness Deason stated that real benefits from the non-regulated businesses would flow to Gulf's customers, even though Southern Company made the investment and is at risk for its capital investment. He argued that Gulf's customers made no investment and they are not at risk should the non-regulated businesses fail, yet they would still receive benefits equal to two percent of the non-regulated companies' revenue.

Gulf's witness Deason testified that OPC witness Dismukes cited the United Telephone Company Order[23] issued by us in 1989 as support for the imputed revenues she recommends. Witness Deason argued that the language quoted by witness Dismukes is incorrect, not relevant to the facts in this case, pre-dates the adoption of the Rule 25-6.1351, F.A.C., which sets forth our policy on cost allocations and affiliate transactions, and should not be used as a basis to impute non-regulated revenue to Gulf. He maintained that witness Dismukes' language appears to indicate that we should embraced the concept of imputing revenue as an ongoing practice, even though we subsequently struck the paragraph in the Order that she cited as support for her assertion. Moreover, witness Deason argued that in the United Telephone Company's decision, we did not require an imputation based on total revenue, instead, it allowed the revenue of United Telephone Long Distance (UTLD) to be reduced by the access charges UTLD had to pay to reach the local network. He also argued that the facts and circumstances leading to our

[23] See Order No. 18939, issued March 2, 1988, in Docket No. 870285-TI, In re: United Telephone Company of Florida.

decision in 1985 (sic) and witness Dismukes recommendation to impute revenues to Gulf in 2011 are contrastively not the same.

Finally, witness Deason asserted that our policy on cost allocations and affiliate transactions are found in Rule 25-6.1351, F.A.C., and non-regulated subsidiaries are not required to impute revenues to a regulated utility pursuant to this Rule. Therefore, he testified that we should reject witness Dismukes recommendation because it is unsupported by the facts, violates principles of good regulatory policy, and would penalize Gulf for being part of the Southern Company.

OPC witness Dismukes testified about the importance of examining transactions between affiliates and regulated companies. She argued that Gulf and its affiliates have a close relationship as members of the same corporate family, which makes it necessary for the cost allocation and pricing methodologies to be periodically scrutinized to ensure that the regulated companies are not subsidizing the non-regulated companies. As a result of the relationship between Gulf and its affiliates, which contributes to expenses included on the Company books, there still exists an incentive to allocate or shift costs from non-regulated companies to regulated companies to reap higher profits for shareholders, even though an established methodology for the allocation and distribution of affiliate costs are in place. Witness Dismukes pointed out that Rule 25-6.1351, F.A.C., specifies criteria for electric utilities that do business with affiliates, and she cited subsection (3), which states that the purchases from the utility by the affiliate must be at the higher of fully allocated cost or market price. It further states that purchases from the affiliate must be at the lower of fully allocated cost or market price.

Witness Dismukes testified that we have addressed affiliate transactions in a prior case.[24] She maintained that it is the utility's burden to prove its costs are reasonable, and the standard to use in evaluating affiliate transactions is whether those transactions exceed the going market rate or otherwise are inherently unfair.

Gulf is one of four regulated utilities of the Southern Company, which includes several non-regulated subsidiaries.[25] Witness Dismukes noted that Southern Company's non-regulated activities have increased in recent years and Gulf engages its affiliates for a variety of services. Specifically, Gulf contracts with SCS for a variety of managerial and professional services, Alabama Power for mail processing services, Georgia Power and Mississippi Power for shared plant costs, Southern Nuclear for siting services, SouthernLINC for wireless services, and Southern Management for financial services. Witness Dismukes also asserted that Gulf provides various services to its affiliates, such as office space, information technology, and power sales.

Background information regarding the Southern Company was provided that recounts the history of the company, when operations were diversified, and how it expanded over the years to

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[24] United Telephone Long Distance, Inc. and United Telephone Company of Florida v. Katie Nichols et al, 546 So. 2d 717, 719 (Fla. 1989) (hereinafter United Telephone).

[25] Southern Company's non-regulated subsidiaries include: Southern Power Company, SouthernLINC Wireless, Southern Nuclear, Southern Electric Generating Company, Southern Company Services, Southern Holdings, and Southern Renewable Energy.

address the whole market. Witness Dismukes asserted that the non-regulated companies benefit from the operating companies' reputation, goodwill, and corporate image; association with large, financially strong, well-entrenched electric companies; and personnel from the service company. She also attributed, in part, Southern Company's high credit rating to the stable cash flows and financial support it receives from its four regulated utility operating companies. Witness Dismukes argued that the benefits the non-regulated affiliates receive stem from the regulated companies that was the foundation of Southern Company before it ventured into the non-regulated market.

Witness Dismukes contended that an affiliate of Gulf, Southern Renewable Energy, was recently formed and no costs have been allocated from SCS to Southern Renewable Energy. Thus, witness Dismukes asserted that it's equitable to assess a two percent compensation to balance the benefits received by the non-regulated companies from their association with the regulated companies and to address the fact that no costs were allocated to Southern Renewable Energy. To support her assertion she cited the cost accounting standards that were provided by the Cost Accounting Standards Board as an authoritative source. Moreover, witness Dismukes argued that we have imposed a compensation payment in a prior case. She asserted a two percent payment should be assessed the non-regulated companies based on their earned revenues to compensate the regulated operating companies for the significant intangible benefits the regulated operating companies provided to the non-regulated companies by their close affiliation and association. Witness Dismukes contended that such payment would increase the Company's test year revenue by $1.5 million and compensate the regulated companies for the intangible benefits they provide the non-regulated companies through their affiliation.

OPC further asserted that Fitch Ratings recognized benefits the regulated companies provide Southern Company and maintained that those benefits flow through to the non-regulated affiliates.

We agree with Gulf that per Rule 25-6.1351(2)(g), F.A.C., non-regulated products and services are not subject to price regulation by us, are not included for ratemaking purposes, and are not reported in surveillance.

We note that the fulcrum of this issue is OPC's contention that the non-regulated companies receive benefits, at no cost, through their association with the four operating companies.[26] According to OPC witness Dismukes, the non-regulated companies benefit from their:

(1) use of the companies' reputation, goodwill, and corporate image;

(2) association with large, financially strong, well-entrenched electric companies;

(3) use of personnel from the service company, SCS; and

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[26] Southern Company's regulated utilities.

(4) the high credit ratings that the Southern Company's receives, in part, that stems from stable cash flows and financial support from the operating companies.

We agree with OPC's arguments regarding the importance of examining transactions between affiliates and regulated companies, such as Gulf, and the necessity to periodically scrutinize the cost allocation and pricing methodologies to ensure they are valid. Moreover, we acknowledge that the allocation factors used by the Company incorporate the benefits the non-regulated companies receive from their affiliation with Gulf. We note that OPC witness Dismukes argued that Gulf is not adequately compensated from the non-regulated companies for the intangible benefits they receive; however, she failed to provide record evidence to support her allegation. Moreover, Gulf witnesses McMillan and Deason sufficiently rebutted OPC witness Dismukes' benefits argument and recommendation regarding assessment of a two percent compensation payment on the non-regulated companies to balance the intangible benefits they receive from their affiliation and association with the regulated companies.

We find that Gulf's witnesses McMillan and Deason's arguments more accurately reflect the proper interpretation of the authoritative sources, as well as the United Telephone cited by OPC witness Dismukes as support for her recommendation.

Thus, we agree with Gulf that the record before us does not provide a legal or factual basis for assessing the compensation payment recommended by OPC, FIPUG, and FEA. In addition, we believe that if the two percent compensation payment was assessed, it would be unprecedented and thus reduce the actual revenue of the Company by $1.5 million because the revenue would be imputed.

We note that Gulf witness McMillan testified that Gulf is a smaller operating company and it:

(1) receives, at-cost, many professional, technical, corporate, and support services from SCS that would normally be performed by Gulf's employees and result in higher costs.

(2) is able to keep its costs down by augmenting its employees in specialized areas with SCS employees, instead of hiring additional employees.

(3) shares resources with SCS that enables Gulf to utilize the talent of a centralized pool of professionals on a ongoing basis that results in cost savings due to economies of scale and access to highly trained professionals that would be difficult to replicate at the Company's level.

Based upon the record evidence in this proceeding, we find that Gulf is adequately compensated by the non-regulated companies for the intangible benefits they receive from their association with Gulf and the non-regulated companies do not benefit from high credit ratings as alluded to by OPC witness Dismukes.

For the foregoing reasons, we find that Gulf is adequately compensated by the non-regulated affiliates through services that it receives at-cost, shared resources it uses to augment its employees that results in cost savings, and access to a centralized pool of professionals that would be difficult to replicate at the Company level. Thus, no additional measures shall be implemented by us to compensate Gulf, and no adjustment shall be made to compensate the regulated operating companies as discussed below.

Compensation Payment for Non-Regulated Companies

As discussed above, in this proceeding OPC asserted that we should increase operating revenues by $1,500,000 for a 2 percent compensation payment from non-regulated companies. For the reasons discussed above, we find that Gulf is adequately compensated by the non-regulated affiliates through services that it receives at-cost, shared resources it uses to augment its employees that results in cost savings, and access to a centralized pool of professionals that would be difficult to replicate at the Company level. Therefore, operating revenue shall not be increased by $1,500,000 for a 2 percent compensation payment from non-regulated companies.

Non-Utility Activities

Gulf witness Neyman asserted that Gulf offers two non-regulated products and one non-regulated service to its residential and commercial customers. The products are Premium Surge and Commercial Surge, which are installed at the customers' home or business to provide them protection from electric surges. Customers who elect to use these products are charged a fee for the equipment and billed through Gulf's monthly bill process, and these products are available to Gulf's customers to offer them additional protection for their property.

Witness Neyman stated that new customers have the option to be transferred to a third-party provider and sign up for AllConnect. AllConnect is a service that allows them to one-stop shop for cable, telephone, home security, etc. There is a large military presence in the area and new customers often ask Gulf's customer service representatives (CSRs) about other service providers. Witness Neyman testified that in response to their questions, the CSR informs them about the AllConnect service and offers to transfer them to the third-party provider that can assist them with other connection needs, at no cost to them.

Witness Neyman disagreed with OPC witness Dismukes' claim that the non-regulated operations obtain substantial benefits from their association with Gulf's regulated operations. She argued that Gulf's customers look for products and services that offer them the best value and Gulf competes with other providers for customers. Witness Neyman argued that, contrary to witness Dismukes' assertion, overheads are charged to Gulf's non-regulated products and services. She argued that OPC witness Dismukes' assertion that SCS labor expenses were not being charged to non-regulated products is mistaken. Overheads are charged via journal entries and examples and responsive documents were provided. Witness Neyman also testified that overheads are charged to AllConnect and calculations were provided illustrating how customer service employees' labor was calculated and charged to AllConnect. A predetermined, per call factor multiplier is used to allocate labor, overheads, administrative and general expenses, and telephone expenses for Gulf's CSC representatives, and this factor is reviewed and adjusted annually.

Witness Neyman testified that through a partnership with other operating companies, Gulf is able to provide services to its customers that it would not be able to provide if it was not a part of the Southern Company. She also stated that profits from the non-regulated operations are credited to the shareholders, not the ratepayers. Witness Neyman testified that Gulf's cost allocations and overheads are detailed appropriately to the non-regulated products. Further, she opined that revenues from the Premium Surge customers reduce the cost resulting in Gulf over-allocating costs to the non-regulated business unit.

Gulf witness McMillan argued that Gulf's non-regulated test year revenues of $1.298 million are less than 0.1 percent of its total retail revenue, and consistent with Rule 25-6.1351(2)(g), F.A.C., are properly recorded below-the-line. Thus, it does not impact its revenue requirement request. Witness McMillan asserted that OPC witness Dismukes' recommendation to move the non-regulated revenue, expenses, and investments above-the-line is not appropriate and her revenue requirement calculations are incorrect. He disagreed with witness Dismukes' recommendation and provided a corrected calculation of what the adjustment would be if we accept her recommendation. He contended that Gulf's investment in its non-regulated operations is removed 100 percent from equity and, according to our policy and ratemaking treatment, return on investment should be calculated on a 13-month average basis.

Gulf argued that OPC provided no evidence demonstrating that costs were misallocated or any precedential authority to support its recommendations. OPC witness Dismukes cited as support the United Telephone Order, which was a 1980's era telecommunications order. However, she failed to mention the 2010 PEF Order,[27] where we rejected her same arguments. Gulf further argued that if we were to accept OPC witness Dismukes' recommendation to move Gulf's non-regulated operations above-the-line, the correct adjustment would be $258,000, not $572,000.

In opposition to Gulf's contention, OPC witness Dismukes argued that we should ensure that Gulf's regulated operations do not subsidize its non-regulated operations or products, as an incentive exists for the non-regulated affiliates to shift costs to the regulated operations in order to yield higher profits for Gulf's parent company. She contended that Rule 25-6.1351(1), F.A.C., addresses costs charged between regulated and non-regulated operations of electric utilities. Further, witness Dismukes stated:

> Utility nonregulated activities should be covered by this rule, and the Commission can utilize the same principles embodied in subsection (3) of Rule 25-6.1351, F.A.C., as guidelines for examining the relations between the Company's regulated and nonregulated operations, thus, ensuring that the regulated operations do not subsidize the nonregulated operations.

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

Witness Dismukes asserted the Company's Cost Accountability and Control Manual does not address how the non-regulated costs and revenue are treated for ratemaking purposes. She testified that three non-regulated products and services, Premium Surge, Commercial Surge and AllConnect, are offered to Gulf's customers through a third-party contractor. A description of these products and services was provided highlighting the protection, warranties, fees and discounts that apply to each of them. A more detailed description and discussion were provided regarding the AllConnect service, which allows customers to one-stop shop for telephone, cable, home security, and newspaper providers when they initiate service with Gulf. Witness Dismukes asserted Gulf's CSRs offer the AllConnect service to customers when the call for electric service with the Company is completed, and if they consent, the caller is transferred to the AllConnect CSR and Gulf receives 25 percent of the revenues generated from services the customers obtain from AllConnect.

Witness Dismukes expressed concern about Gulf's non-regulated operations and asserted that Gulf incurs minimal costs associated with the revenue earned from its non-regulated products and services that are recorded below-the-line, revenue that could not be earned if it was not for the regulated operations. She argued the non-regulated operations receives substantial benefits such as the use of Gulf's name, logo, reputation, goodwill, and corporate image, etc., and these intangible benefits are received at no cost.

OPC witness Dismukes argued that based upon data supplied by Gulf for its non-regulated operations, Gulf earned a return of 21.6 percent in 2009, 24.2 percent in 2010, and 28.9 percent for the projected test year of 2012. She contended the high returns on investment suggest that the costs attributed to the non-regulated operations are abnormal and understated. Witness Dismukes asserted the Company's response to OPC discovery indicates that direct costs are associated with the non-regulated products and services, but no overhead costs are allocated or assigned to the surge products. She did concede, however, that the Company indicated that direct labor expenses for Gulf's employees are charged through its payroll system.

Witness Dismukes testified that all customers that purchase the three non-regulated products and services are Gulf ratepayers, and she presented three options we should consider to ensure the regulated operations are not subsidizing the non-regulated operations. The options address allocating overhead costs, assessing a compensation payment for intangible benefits, returning a portion of the rate of return achieved by the non-regulated operations to the ratepayers, and moving revenues, expenses and investments above-the-line. Witness Dismukes asserted that Gulf has failed to properly allocate costs to the non-regulated operations or demonstrate that it has been adequately compensated for the use of reputation, goodwill, logo, and trained personnel. Thus, she asserted that we should treat the revenue, expenses and investments above-the-line for rate setting purposes.

To implement OPC's recommendation, witness Dismukes developed an adjustment to test year revenue based upon revenue being moved above-the-line. She also testified that if the revenue, expenses and investments are not moved above-the-line, we should order the Company to examine the non-regulated operations, to develop procedures for allocating costs to the non-regulated operations, and to assess the Company a compensation payment of at least 2 percent of annual revenue.

Gulf witness McMillan asserted that Gulf's non-regulated test year revenue of $1.298 million is less than 0.1 percent of its total retail revenue. Gulf addressed OPC witness Dismukes' recommendation and alternate recommendation that Gulf's non-regulated activities be audited. Primarily, OPC recommends that we move all the revenue, expenses, and investment associated with these non-regulated operations above the line for ratemaking purposes. Gulf argued that we should reject OPC's recommendation because we lack that legal authority to regulate non-regulated operations.

We agree with Gulf that its non-regulated activities and associated expenses shall be recorded below-the-line and shall not impact the Company's revenue requirement request. We note that Rule 25-6.1351(2)(g), F.A.C., defines non-regulated operations as "services or products that are not subject to price regulation by the Commission or not included for ratemaking purposes and not reported in surveillance."

We note that the basis for OPC witness Dismukes' opinion are the high returns on investment which suggests that costs attributed to the non-regulated operations are abnormal and understated. Witness Dismukes asserted the Company's response to OPC discovery indicated that direct costs are associated with the non-regulated products and services but no overhead costs are allocated or assigned to the surge products. She conceded, however, that the Company indicated that direct labor expenses for Gulf's employees are charged through its payroll system. Thus, witness Dismukes' arguments appear to have been based upon Gulf's response to a discovery question regarding SCS labor expenses not being charged to non-regulated products. We note that cost allocation and overheads are assigned appropriately to the non-regulated products, and we agree with Gulf's witness Neyman that, based on how the Premium Surge costs are allocated, they reduce the cost and result in Gulf over-allocating costs to the non-regulated business unit.

Furthermore, we find that the record in this proceeding does not support OPC's allegation that specific costs were not allocated properly. Moreover, OPC witness Dismukes acknowledged that Rule 25-6.1351(1), F.A.C., does not cover utility non-regulated activities.

Based upon the record evidence, we find the methodology used by the Company for allocating costs is reasonably effective and Gulf has appropriately accounted for revenue, expenses, and investments associated with the non-regulated operations. Therefore, we further find that Gulf has appropriately accounted for revenue, expenses, and investment associated with the non-regulated activities and no adjustment is necessary to increase test year revenue for Gulf's non-regulated products and services. The revenue and expenses for these non-regulated activities are not subject to price regulation by us, not included for ratemaking purposes, and not reported in surveillance, pursuant to Rule 25-6.1351(g), F.A.C.

Projected Level of Total Operating Revenues

We find that the appropriate projected level of total operating revenue for the 2012 projected test year is $481,909,000 ($499,311,000 system).

Removal of Fuel Revenues and Fuel Expenses

We find that Gulf has made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel Adjustment Clause.

Removal of Conservation Revenues and Conservation Expenses

As adjusted, we find that Gulf has made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause. As shown on witness McMillan's direct testimony Exhibit RJM-1, Schedule 6, Gulf's ECCR depreciation and property tax adjustments were $352,000 and $146,000, respectively. The ECCR depreciation expense adjustment shall be increased to $375,000 and the ECCR property tax expense shall be increased to $156,000.

Removal of Capacity Revenues and Capacity Expenses

We find that Gulf has made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause.

Removal of Environmental Revenues and Environmental Expenses

We find that Gulf has made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause. Consistent with the Stipulation entered into by all parties and approved by us on November 1, 2011, the Crist Units 6 and 7 turbine upgrade investments and expenses were removed from the Environmental Cost Recovery Clause and are now being included for recovery in base rates in this proceeding.

Removal of Non-Utility Activities From Net Operating Income

Based on the record evidence in this proceeding, as discussed above, we find that Gulf made the appropriate adjustments to remove all non-utility activities from net operating income.

Appropriate Adjustments to the Expenses Allocated to Gulf as a Result of Affiliate Transactions

The merits of this issue are discussed below, and we find that no further adjustments are warranted in this matter. Transactions with affiliates are addressed separately below and any adjustments are discussed therein. No further adjustments are necessary.

Allocation of SCS Costs to Southern Renewable Energy (SRE)

SRE is listed in the Company's Form 10-K that is provided in MFR Schedule F, as a new subsidiary of the Southern Company that was formed on January 25, 2010, to construct, acquire, own, and manage renewable generation assets. The Company stated that new business opportunities are more risky; however, they offer potential higher returns than rate-regulated operations.

Witness McMillan testified that "Southern Company Services (SCS) is a subsidiary of Southern Company which provides various services to Gulf and other subsidiaries of Southern Company." He stated that Gulf receives professional and technical services such as general and design engineering for transmission and generation; system operations for the generating fleet and transmission grid; and various services and support in accounting, supply chain management, finance, treasury, human resources, information technology, and wireless communications.

Witness McMillan argued that SCS provides all services at cost and that these costs are determined and billed using two methods. Costs are either directly assigned to the company receiving the services or allocated among the subsidiaries receiving the services based on a pre-approved cost allocator based on the services received. Typical allocators include employees, customers, loads, generating plant capacity, and financial factors. The methodology for developing the allocators has not been changed since Gulf's last rate case. The allocators are approved by SCS and by management of the applicable operating companies, and updated annually based on objective historical information. Witness McMillan stated that SCS supports the activities of each company and maintained that the regulated companies require more support than the unregulated companies.

Gulf argued that since SRE was not in operation in 2009, costs were not allocated to it for the test year. To remedy the situation, OPC proposed a 2 percent compensation payment on SRE analogous to that described above. The Company argued that such payment would result in additional imputed revenue to Gulf and asserted that it is inappropriate in this instance for the same reasons discussed above. Gulf argued that evidence shows that the total O&M allocation to Gulf would increase by approximately $1,159,000 if all the SCS fixed factors were updated based on 2010 data. Gulf's used the 2009 data for its rate request and no adjustment should be made for SRE.

OPC witness Dismukes testified that it is important to review cost allocation methods and techniques used by affiliates to ensure that the company's regulated operations are not being subsidized by the non-regulated operations. She argued that Rule 25-6.1351, F.A.C., Cost Allocation and Affiliate Transactions, details the policy that must be followed by electric utilities when transacting with affiliates.

Witness Dismukes asserted that SRE, an unregulated affiliate, was formed in January 2010, and she pointed out that the Southern Company 2010 Form 10-K indicated that the new business investments offer higher returns and involve a higher risk than the regulated operations. She stated that the charges from SCS to Southern Company subsidiaries have increased by $513 million or 57 percent since 2005 and the charges to Gulf have increased by $44 million or 82 percent over the same time period. Witness Dismukes opined that SCS' total billings have increased in part because amounts billed to the utility operating companies have increased while the amounts billed to the non-regulated companies have decreased.

Witness Dismukes stated SCS uses three methods to assign costs to affiliates. Expenses are assigned on fixed percentage distribution when they are for the benefit of two or more affiliates. The direct method is used when the costs are incurred solely for the benefit of one company, and the direct accumulative distribution method is used for work orders when there is no established fixed percentage allocator available.

Because no costs have been allocated to SRE since it was formed in 2010, witness Dismukes argued that we should assess a 2 percent compensation payment based on the amount of revenue earned by the non-regulated companies. OPC further argued that as a result of SRE not being allocated costs from SCS, Gulf's costs have been overstated. Ratepayers should not be forced to subsidize SRE, which is a non-regulated company.

SRE is a subsidiary of the Southern Company, which was formed in 2010 and SCS has not allocated any costs to SRE. We note that there was little testimony provided specific to costs being assigned or allocated to SRE, which is a non-regulated affiliate of Gulf. The facts presented in this proceeding show that costs are either directly assigned to the company receiving the services, or allocated among the subsidiaries receiving the services based on a pre-approved cost allocator based on the services they receive from SCS.

Gulf used factors based on the 2009 data that was available for its budget for the 2012 test year. Gulf provided supporting documentation that shows the allocators used to assign costs are updated annually based on objective historical information, approved by SCS and by management of the applicable operating companies, and reported annually to the Federal Energy Regulatory Commission (FERC) and state commissions that have authority to supervise these factors. As discussed below, the factors have been used for more than 25 years, reviewed by us in Gulf's last two rate cases, and neither the FERC nor this Commission have recommended a change to the factors.

We note that the record evidence indicates that charges from SCS to Southern Company subsidiaries have increased by $513 million or 57 percent since 2005 and that charges to Gulf have increased by $44 million or 82 percent over the same time period. However, we note that no evidence was presented that indicated Gulf was allocated a higher percentage of SCS costs as a result of SCS costs not being allocated to SRE, or that SRE obtained services from SCS that were misallocated.

Gulf argued that SCS supports the activities of each company in the Southern corporate family, and the regulated companies require more support than the unregulated companies. The record also shows that if all the updated 2010 allocation factors are used, Gulf's revenue request would actually increase by approximately $1.2 million.

We find OPC's argument that SCS costs allocated to Gulf are overstated as a result of costs not being allocated to SRE is not supported by the record. We further find that an adjustment to the expenses to allocate costs to SRE are inappropriate absent evidence that shows costs were misallocated. We therefore find that it is inappropriate to assess SCS a 2 percent compensation payment based on the amount of revenue earned by the non-regulated companies simply because no costs were charged to SRE since it was formed in 2010.

SCS and SRE are non-regulated affiliates of Gulf and subsidiaries of the Southern Company. Pursuant to Rule 25-6.1351, F.A.C., Cost Allocation and Affiliate Transactions, adjustments are not appropriate and the record in the instant case does not provide a legal or factual basis for requiring SCS to allocate costs to SRE. Consequently, we decline to assess SCS a two percent compensation payment as recommended by OPC.

Adjustments to Allocation Factors Used to Allocate SCS Costs to Gulf

SCS is a subsidiary of Southern Company, and an affiliate of Gulf, which provides services at-cost to Southern Company and its other subsidiaries. Gulf is a subsidiary of the Southern Company and receives professional and technical services from SCS, such as general design and engineering for transmission and generation; system operations for the generating fleet and transmission grid; and various corporate services and support in areas such as accounting, supply chain management, finance, treasury, human resources, information technology, and wireless communications.

All SCS costs are either directly charged or allocated based on a pre-approved cost allocator for the type of services performed. The methodology for developing the allocators has not changed since Gulf's last rate case and it includes employees, customers, loads, generating plant capacity and financial factors. Witness McMillan argued that the allocators are approved by SCS and management of the applicable operating companies and updated annually based on objective historical information.

Gulf argued the affiliate transactions are provided at cost, with no mark-up for profit, under a rigorous process of direct billings and rational allocations, consistent with Southern Company policy, the FERC, and our requirements. The services provided to Gulf are services that would normally be performed by utility employees and by using SCS, Gulf can augment its personnel in specialized areas, have the advantages of a stable utility workforce, and have the advantage of the economies of scale associated with specialized employees serving a larger organization. Moreover, Gulf argued that if additional employees were hired instead of SCS or another operating utility's employees, Gulf's costs would be higher.

Gulf provided detailed documentation and explanations showing how costs are allocated to affiliates. The documentation included spreadsheets reflecting the different expenses that Gulf incurs and how they are allocated by the affiliates. Documentation was also provided that showed affiliate costs, recorded as revenue and expenses, for years 2007 through June 30, 2011, with explanations why certain revenue and expenses increased and decreased during these years.

Witness McMillan asserted that Gulf and its customers receive several benefits from the services provided by SCS. As a smaller operating company, Gulf has access to shared resources that enables Gulf to avoid duplication of personnel and to utilize the talent of a centralized pool of professionals on an ongoing basis. The services Gulf receives from SCS benefits its customers through cost savings due to economies of scale and access to highly trained professionals that would be difficult to replicate at the Company level. Witness McMillan testified that SCS provides technical and professional services and costs are allocated based on the service provided and the most cost-causative type allocator identified for that type of service. He maintained that Gulf has staff who help with hiring and personnel activities but services are not duplicated.

Witness McMillan asserted that the Rule 25-6.1351(3), F.A.C., cited by OPC witness Dismukes that addresses transactions with affiliates, does not apply to services provided by SCS to Gulf because SCS exists solely to provide services to the Southern Company corporate family. This Rule also does not apply to services provided between Gulf and its regulated affiliates.[28] Witness McMillan stated that OPC witness Dismukes referenced a 2001 NARUC letter and Guidelines for Cost Allocations and Affiliate Transactions that are not applicable to Gulf and it affiliates. He asserted that she also failed to note our policies and procedures for cost allocations and affiliate transactions that were adopted after the NARUC guidelines were issued. Witness McMillan argued that the standards issued by the Cost Accounting Standards Board (CASB) that OPC witness Dismukes cited as support for her recommendation state the importance of benefits in distributing common costs only apply to federal procurement contracts. He maintained, however, the cost allocation methods used by SCS are consistent with the CASB principles.

The allocation methodology used by SCS was approved by the SEC in 1985 prior to the repeal of the Public Utility Holding Company Act (PUHCA) and it has been used for more than 25 years to allocate costs among Southern Company's affiliates. Witness McMillan asserted FERC and the state commissions have authority to supervise the allocation methodologies that SCS reports annually to the FERC. He pointed out that the financial factor and other fixed allocation factors are recalculated each year and FERC has made no changes to the factors. Further, the allocations based on the financial factor were used by the Company in its last two rate cases and were reviewed and approved by us. Witness McMillan argued that Gulf's test year costs were based on 2010 factors that used 2009 data, which was the most recent actual data available at the time Gulf prepared its filings for this case.

Witness McMillan asserted that OPC witness Dismukes' recommendation to: (1) convert the financial factor to a two component factor, (2) exclude fuel and purchased power from the operating expense factor, and (3) recalculate some of the fixed allocation factors using 2010 data is flawed and would reduce Gulf's operating budget by $832,284. Witness McMillan testified that witness Dismukes provided an example using Gulf's and Southern Power's revenue per kWh to support her claim that the use of operating revenue in the financial factor could bias the factor. He asserted that she failed to take into account that a larger infrastructure is necessary to support Gulf's regulated retail revenue stream than the non-regulated sales. SCS supports all the affiliate companies activities and the level of support for the regulated companies is greater than that required for the non-regulated companies.

Witness McMillan argued that OPC witness Dismukes' recommendation is unrealistic because it arbitrarily shifts costs from the regulated operating companies to the non-regulated businesses, ignores activities necessary to support the operating companies, and would result in

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[28] Southern Company is comprised of four regulated utility companies: Gulf Power, Alabama Power, Georgia Power, and Mississippi Power.

an unfair allocation that does not adhere to the principle of matching costs allocations with cost incurrence and benefits. Witness McMillan asserted that it is inappropriate to pick and choose factors to update as recommended by OPC witness Dismukes. If the 2010 factors are used, all the updated factors should be used, which would result in an increase to Gulf's share of SCS billing by approximately $1,262,500.

Gulf argued that the factors apply to all companies in the Southern Company system and a change in Florida would result in SCS total costs being under or over recovered until a change was made by the FERC and other state commissions.[29] Gulf further argued that OPC should not be allowed to pick and choose the factors that would result in an artificially reduced revenue requirement.

OPC witness Dismukes testified about the importance of examining transactions between affiliates and regulated companies. She argued that Gulf and its affiliates have a close relationship as members of the same corporate family, which makes it necessary for the cost allocation and pricing methodologies to be periodically scrutinized to ensure that the regulated companies are not subsidizing the non-regulated companies. The relationship between Gulf and its affiliates contributes to expenses being included on the Company's books and an incentive exists to allocate or shift costs from non-regulated companies to regulated companies so that the shareholders can reap higher profits, even though an established methodology for the allocation and distribution of affiliate costs is in place. Witness Dismukes argued that Rule 25-6.1351, F.A.C., provides criteria for electric utilities to use when transacting with affiliates and she cited subsection (3) which states that the purchases from the utility by the affiliate must be at the higher of fully allocated cost or market price. Subsection (3) of the Rule also states that purchases from the affiliate must be at the lower of fully allocated cost or market price.

Witness Dismukes argued that we have addressed affiliate transactions in a prior order. She asserted that the company has the burden to prove that its costs are reasonable, and the standard to use in evaluating affiliate transactions is whether those transactions exceed the going market rate or otherwise are inherently unfair. She also stated that the National Association of Regulatory Utility Commissioners (NARUC) has guidelines that address cost allocations and affiliate transactions for electric and gas operations. According to witness Dismukes, the "4 Guidelines" promulgated by NARUC state that all direct and allocated costs between regulated and non-regulated services should be traceable on the books to the applicable Uniform System of Accounts, indirect costs of each business unit should be spread to the services and products to which they relate using relevant factors, and the allocation methods should not result in regulated companies subsidizing the non-regulated companies. Moreover, witness Dismukes asserted NARUC's Guidelines are based on two assumptions: (1) affiliate transactions raise the concern of self-dealing, and (2) an incentive exists to shift costs from non-regulated operations to regulated operations. She testified that the SCS Cost Accountability and Cost Control Manual states that the factors used to allocate costs between Gulf and its affiliates were approved by the

[29] In addition to Florida, Southern Company has regulated utilities in Alabama, Georgia, and Mississippi that also use the SCS allocation methodologies that are reported annually to FERC.

Security Exchange Commission (SEC), but the authority now rests with the FERC and state legislators.

Gulf is one of four regulated utilities of the Southern Company, which also has several non-regulated subsidiaries. Witness Dismukes pointed out that Southern Company's non-regulated activities have increased in recent years and Gulf engages its affiliates for a variety of services. Gulf contracts with SCS for a variety of managerial and professional services, receives mail processing services from Alabama Power, shares plant costs with Georgia Power and Mississippi Power, receives siting services from Southern Nuclear, wireless services from SouthernLINC, and financial services from Southern Management.

Witness Dismukes asserted that Gulf provides various services to its affiliates, such as office space, information technology, and power sales. She testified that, during the projected test year, Gulf's transactions with its affiliates were approximately $155 million with nearly $81 million in charges from its affiliates included in test year Operations and Maintenance (O&M) and Administrative and General (A&G) expenses. Witness Dismukes asserted that the total O&M and A&G expenses indicate that 28 percent of the costs are charged from affiliates. And for just total A&G expenses, 73 percent are charged from SCS. Since 2005, charges from SCS to subsidiaries have increased by 57 percent and charges from SCS to Gulf have increased by 82 percent. She pointed out that SCS total billings to the utility operating companies have increased while amounts billed to the non-regulated companies have decreased.

SCS uses three methods to allocate costs to its affiliates: direct assignment, fixed percentage distributions, and direct accumulative distributions. The direct assignment method assigns costs that are incurred solely for the benefit of one utility, the direct accumulative distribution method assigns costs based on work order specific assumptions when no established fixed percentage allocator is available, and the fixed percentage distribution method assigns costs that are incurred for the benefit of two or more affiliates. Witness Dismukes testified that during the test year $5.2 million of expenses were allocated using the direct accumulative distribution method and $40 million were charged using the fixed percentage distribution method.

Witness Dismukes contended that Gulf used allocation factors consisting of statistics that include kilowatt hours (kWh), customers, employees, plant capacity (kW), gas burned (MMBTU), insurance premiums, billed labor, and a financial factor which consists of an equal weighting of fixed assets, operating expenses, and operating revenue. She argued that there are problems with the factors because the data is stale and the factors fail to incorporate benefits the non-regulated companies receive from their association with the regulated operating companies.

Witness Dismukes argued that the allocation factors Gulf used to allocate the projected 2012 expenses were based on data that was three years old. She stated that the allocation factors might be acceptable if the relationship between Gulf and the affiliates remains constant but she asserted that Schedule KHD-6 shows the relationship is not constant and can vary from year to year. She argued that given the total dollars being allocated, a minor change could result in a significantly lower amount of expenses for the test year. For example, if the financial allocator is modified by one percent, the common administrative and general expenses could be reduced by

$1 million. Witness Dismukes also argued that SRE was formed in 2010 and purchased a 30 MW solar photovoltaic plant that began commercial operation, and SCS did not allocate any costs to that company for the test year. She contended that costs were overstated for the Company's projected test year as a result of no cost allocations to SRE and the use of 2009 data to allocate the projected 2012 test year expenses.

Witness Dismukes expressed several problems that she has with the financial factor that is used to allocate administrative and general expenses. The factor consists of the average of net fixed assets, operating expenses, and operating revenue, and given the differences between the regulated and non-regulated companies the inclusion of the revenue in the allocation factor overstates the allocations to the regulated companies. To support her assertion witness Dismukes provided a hypothetical scenario in her testimony to show how the costs for the regulated companies would be overstated if Southern Power, an non-regulated affiliate, had a lower revenue per kWh than the operating companies. The hypothetical scenario indicated that if Gulf revenue per kWh in 2010 was 9.88 cents and Southern Power's wholesale kWh 4.72 cents, costs would be overstated. Other problems were expressed such as the effect the expense factor has when used for the financial allocator.

To correct the problems with the allocation factors, witness Dismukes asserted that we should update the data used in the factors and she identified those factors that she was able to update. She also stated that the financial factor should be adjusted to remove revenue from the composite factor. She pointed to the cost accounting standards that relate to cost allocations to affiliates that were provided by the CASB as an authoritative source.

We agree with Gulf that per Rule 25-6.1351(2)(g), F.A.C., non-regulated products and services are not subject to price regulation by us, are not included for ratemaking purposes, and are not reported in surveillance. However, we agree with OPC that transactions between affiliates and regulated companies should periodically be reviewed to ensure that the regulated companies are not subsidizing the non-regulated companies. OPC provided testimony about Rule 25-6.1351, F.A.C., and we note that the Rule establishes cost allocation requirements to ensure proper accounting for affiliate transactions and utility non-regulated activities. We also agrees with OPC that cost allocation and pricing methodologies should be periodically examined to ensure they are valid.

Both OPC and Gulf offered testimony about the NARUC Guidelines and the CASB Standards. We acknowledge that the NARUC Guidelines address cost allocations and affiliate transactions and the CASB cost account standards relate to the allocation of costs to affiliates. However, we find Gulf's arguments about the relevancy of these guidelines and standards persuasive.

As discussed above, three methods are used to allocate costs to affiliates: direct assignment, fixed percentage distributions, and direct accumulative distributions. Moreover, the allocation factors consist of statistics that include kWh, customers, employees, kW, MMBTU, insurance premiums, billed labor, and a financial factor which consists of an equal weighting of fixed assets, operating expenses, and operating revenue.

Gulf obtains a variety of professional and technical services from SCS and the costs are allocated based on the services provided and the most cost-causative type allocator identified for that type of service. Based on the scope of services that Gulf receives from SCS, we find that the total costs that Gulf has been charged by SCS is not the proper mechanism to determine if the allocation factors should be changed. However, we note that the record shows that during the projected test year, Gulf's transactions with its affiliates are projected to be approximately $155 million with roughly $81 million of the charges from its affiliates included in test year O&M and A&G expenses. The record shows that 28 percent of the total O&M and A&G expenses are charged from affiliates, and 73 percent are charged from SCS. Further, we note that since 2005, charges from SCS to subsidiaries have increased by 57 percent, and charges from SCS to Gulf have increased by 82 percent.

OPC witness Dismukes' belief that costs were not properly allocated is based on the fact that the total billings to the utility operating companies, and Gulf in particular, have increased while amounts billed to the non-regulated companies have decreased. OPC witness Dismukes argued that there are problems with the allocation factors used because the data is stale and fails to incorporate benefits the non-regulated companies receive from their affiliation with Gulf. However, no record evidence was provided by OPC witness Dismukes that supports her assertion that specific costs were misallocated.

OPC witness Dismukes recommended that the factors be modified to remove the revenue component from the allocation factors. Witness Dismukes argued that inclusion of revenue in the factors under-allocates costs to the non-regulated companies because new companies such as SRE produced little revenue relative to investment expenses. We note that OPC witness Dismukes' recommended adjustment to the allocation factors would reduce Gulf's operating budget by $832,284.

Gulf's test year costs were based on 2010 factors that used 2009 data, which were the most current information available to Gulf at the time Gulf prepared the test year data for its original filing in this case. We agree with Gulf that OPC witness Dismukes' recommended changes to the allocation factors using some of the updated 2010 data are flawed. We believe that if allocation factors are updated and used to calculate the Company's revenue requirement, all the factors should be updated using the 2010 factors as argued by Gulf witness McMillan. We further find that OPC should not be allowed to pick and chose the factors that would result in a reduced revenue requirement.

We find that adjustments are not necessary to the allocation factors used to allocate SCS costs to Gulf. The factors are provided annually to the FERC for review, they have been used for over 25 years, they were approved by us in Gulf's last two rate cases, and neither the FERC nor our auditors have recommended changes to the factors. Therefore, we find that Gulf's arguments are sufficiently supported by the record and the methodology and allocation factors SCS uses to allocate costs to Gulf and its other affiliates shall not be adjusted as proposed by OPC.

Costs Associated with SouthernLINC

Gulf witness Jacobs testified that through use of wireless technology, Gulf is able to provide better service to its customers by remotely communicating work orders to service vehicles in the field. The expenses in the 2012 test year for SouthernLINC are for unique communication services necessary for the continued reliable operation of Gulf's distribution and transmission system that have no commercial comparison in the marketplace. SouthernLINC markets its services commercially and Gulf and other operating companies of the Southern Company electric system benefit financially from those commercial operations because the contribution to fixed costs from the commercial operations reduces the billing to Gulf and its sister companies. Witness Jacobs asserted that SouthernLINC's services are billed to Gulf at cost less the contribution to fixed costs obtained from its commercial subscribers.

Gulf argued that SCS bills Gulf for wireless communication services it uses for its business that are provided by SouthernLINC through its work order system. Gulf stated that approximately five percent of SouthernLINC's costs were allocated to Gulf based upon SouthernLINC's total revenue requirements, net of commercial revenues.

Witness Jacobs contended that OPC acknowledged that profit from SouthernLINC's commercial aspects declined in 2009 and 2010, which resulted in less of SouthernLINC's total costs being defrayed. He asserted that Gulf's customers are not subsidizing the non-regulated operations, but instead, they are benefiting from reduced costs that SouthernLINC charges Gulf for telecommunication services that are vital to its operations. SouthernLINC was established to provide digital wireless voice and data services to Gulf and its affiliates because there were no alternatives in the commercial market. Prior to SouthernLINC's 800 MHz telecommunication system that provides push-to-talk communications on a hand-held device that Gulf's employees can keep with them while working on the electric network, communication was limited and only available from the work vehicle. Witness Jacobs argued that as a result of the services provided by SouthernLINC, functionality was expanded, personal safety and operational productivity improved, and the technology that was developed to meet the needs of the operating companies of the Southern Company electric system was made available to other users to help defray the costs of the system.

Witness Jacobs asserted that SouthernLINC's network corresponds with the entire Southern Company electric system and enables Gulf to automate its work order dispatch and vehicle location for service crews. He pointed out that as additional smart grid equipment is installed on Gulf's transmission and distribution systems, SouthernLINC's interoperability between transmission and distribution automation systems will result in enhanced monitoring, switching, and fault location.

Witness Jacobs pointed out that Gulf serves DeFuniak Springs, Bonifay, Graceville, Century and other small communities, and in many of these rural communities SouthernLINC is the only wireless service provider. SouthernLINC's system was designed to meet the rigorous standard of utility construction and each site critical to electric operations has a generator sufficient to power the site for several days, battery backup capabilities, controllers, and base radios. Witness Jacobs maintained that as a result of SouthernLINC's wireless network infrastructure resiliency, it was operational and Gulf was able to immediately begin restoration efforts after its territory was affected by Hurricane Ivan. He argued that the unique characteristics of SouthernLINC's network are vital to Gulf's operations and its ability to provide reliable and efficient service to its customers and the costs are reasonable and prudent. Witness Jacobs further stated that other communication carriers sustained severe damage to their networks after the storm and their customers experienced limited communications for days.

OPC witness Dismukes opined the $294,765 included in the test year to support SouthernLINC should not be charged to Gulf. According to Southern Company's Form 10-K, SouthernLINC is a non-regulated affiliate that provides digital wireless communications to the Southern Company and its subsidiaries, and markets services to the public and telecommunication providers in the Southeast. SouthernLINC's revenues decreased in 2009 and 2010 as a result of lower average revenue per subscriber and fewer subscribers due to competition. Witness Dismukes asserted that information that Gulf provided indicates that all costs not recovered through commercial revenues are assigned to affiliates, and the 2012 charges to Gulf are projected to increase due to a decrease in commercial revenue. She testified that SouthernLINC's losses should not be subsidized by Gulf's ratepayers.

OPC argued that during the period 2008 to 2011, Southern Company's Form 10-K shows that SouthernLINC's operating revenues have decreased due to its inability to compete with other wireless providers. OPC further argued that Gulf and the operating companies should not subsidize SouthernLINC by sharing all of the charges not recovered through commercial revenues.

Gulf witness Jacobs provided extensive testimony explaining how costs are allocated to Gulf and how its ratepayers are not subsidizing SouthernLINC's losses. We note that SouthernLINC provides unique wireless telecommunication services that are critical to Gulf's regulated operations, and also markets technology to commercial customers to increase its revenue base and offset costs that otherwise would have to be paid by Gulf and the other operating companies.

Based on the record evidence, we find that projected charges in the 2012 test year are supported by the evidence in this case. We further find that costs are properly charged to Gulf based upon the type of services Gulf receives from SouthernLINC, and that those charges are adequately accounted for through work orders and recorded in the appropriate FERC account.

We recognize the importance of monitoring the activities of affiliates to ensure that the regulated companies are not subsidizing the non-regulated affiliate companies. However, we do not find that Gulf is subsidizing SouthernLINC and agrees with Gulf witness Jacob that revenues from SouthernLINC's commercial customers are used to defray or reduce the total cost that Gulf and the other operating companies are charged. Thus, we find that OPC witness Dismukes' contention that Gulf is subsidizing SouthernLINC's losses is not supported by the evidence.

Finally, we find that Gulf's ratepayers benefit from the services that it receives from SouthernLINC that enables Gulf to provide a resilient wireless network and respond more promptly to service problems through an improved communications network. The costs in the 2012 test year are associated with unique services that Gulf uses to provide prompt, reliable and efficient service to its ratepayers. Therefore, we find that they shall not be removed from the Company's projected costs for the test year.

Costs Related to Work Order 466909

We find that the costs associated with a system-wide asset management system related to work order 466909 should have been capitalized, rather than expensed, resulting in a reduction to test year jurisdictional O&M of $343,847 ($344,204 system).

Costs Related to Work Orders 46EZBL, 46IDMU, 46LRBL, 47VSES, 47VSTB, 47VSTH, 47VSZ1, and 47VSZ5

Gulf has acknowledged that the original approved work orders referenced above could not be located and provided in this case. Gulf witness McMillan testified that these specific work orders had been misplaced as a result of a clerical error, but that detailed information about each work order, how they were accounted for, and how the costs were allocated was available via the Company's accounting records.

Witness McMillan testified that Work Order 46EZBL relates to the license, IT labor, and resource usage of the eGain software package. Witness McMillan went on to explain that the eGain software packages serve to manage incoming customer information requests to the appropriate department. Gulf also provided an explanation of how the work was accounted for and the allocation method used to charge Gulf.

Witness McMillan testified that Work Order 46IDMU relates to the IT labor and resource usage related to the Load Data Analysis (LDA) database support. Witness McMillan went on to explain that the LDA tool collects data related to metering, weather, interval, customer base load, system hourly load and substation load to be used for analysis and for the calculation of billing rates. Gulf also provided an explanation of how the work was accounted for and the allocation method used to charge Gulf.

Witness McMillan testified that Work Order 46LRBL relates to the license, IT labor, and resource usage for the Oracle Utilities Rate Manager software system. Gulf went on to explain that this software system provides an automated system which integrates business functions and provides accurate, timely, and competitive response of rate pricing, design, and analysis. Gulf also provided an explanation of how the work was accounted for and the allocation method used to charge Gulf.

Witness McMillan testified that Work Orders 47VSTH, 47VSES, 47VSZ5, 47VSTB and 47VSZ1 relate to allocations of Enterprise Solutions Support to Supply Chain Management, which supports various other systems. These various other systems provide asset management software used in the Company's warehouses, the processing of the procurement and payment of goods and services, the front-end imaging system, and initial work-flow system used for invoices and expense requests. Gulf also provided an explanation of how the work was accounted for and the allocation method used to charge Gulf.

OPC witness Dismukes recommended that the costs associated with these work orders be disallowed because OPC believes that Gulf has failed to support the need for these services. Witness Dismukes also stated that "support documentation is necessary to satisfy Gulf's burden of proof," and disagreed with Gulf witness McMillan's statement that Company descriptions and spreadsheet explanations should be sufficient.

We agree with OPC witness Dismukes that support documentation is necessary when analyzing and evaluating any company's requested expenses. In this instance, we find that Gulf has provided sufficient support documentation to establish that these work orders are legitimate. We disagree with OPC's argument that the Company was unable to provide the Work Orders demonstrating the need, the method used to allocate the costs, and the company(ies) the costs should be charged to. Based on the description of services and cost allocation information provided for these work orders, we find that these work orders represent normal and prudent operating activities.

Based on the above, we find that Gulf has adequately documented and justified the costs associated with Work Orders 46EZBL, 46IDMU, 46LRBL, 47VSES, 47VSTB, 47VSTH, 47VSZ1, and 47VSZ5. Therefore, we find that the costs related to these work orders shall not be removed from operating expenses.

Costs Related to Work Order 471701

Gulf provided Work Order 471701, which lists the description of services as "Accumulate cost associated with the SEC inquiry of the Southern Electric System" which OPC used as the foundation of its argument that the costs associated with this work order should be removed from the test year operating expenses. Gulf rebutted OPC's argument by explaining that the work order was simply outdated and that the costs were in fact related to the Company's Comptroller organization. Gulf also provided additional testimony about the current charges associated with Work Order 471701 and why it was necessary and in the interest of Gulf's customers. Witness McMillan went on to elaborate that the special projects include the transition and implementation of new accounting, finance, and treasury infrastructure associated with the Company's Enterprise Solutions project, accounting research on new FASB regulations, as well as other various need-based special projects.

We agree with OPC witness Dismukes, that on its surface, an adjustment appears warranted for Work Order 471701, if it were in fact related to an SEC inquiry of the Southern Electric System that was initiated in 1989. However, based on the Company's explanation discussed above, we find that the Company has supported the costs associated with Work Order 471701 as being necessary and prudent. As such, we find that the costs related to Work Order 471701 shall not be removed from operating expenses, though we would suggest that the Company consider no longer using this outdated work order for activities that are unrelated to an SEC inquiry to avoid any confusion in the future.

Costs Related to Work Order 473401

Gulf's witness McMillan summarized that the activities relating to this work order are necessary and the appropriate cost allocation factors were used to assign costs to Gulf. He asserted that benefit reviews are conducted on a recurring basis, even though the benefit review activities covered by Work Order 473401 takes place every other year. Witness McMillan testified that there are other normal benefit review activities that did not occur during the test year and the amount included in the test year should not be amortized over two years because it represents an on-going level of benefit review activity. He asserted that normal benefit activities are performed by human resources that include analyzing and evaluating compensation packages in relation to the market. Witness McMillan further argued that the work order that OPC witness Dismukes selected included a specific survey, however, there are other benefit review activities similar to the survey that are ongoing.

Gulf described the benefit reviews as outside consulting activities performed by Southern Company's human resources executive management. Gulf argued that since February 2009, five benefits reviews have been conducted on a varied basis. The benefit review activities included: (1) assessment of the potential impact of market changes and regulatory filing requirements on projected accounting costs, (2) assessment of projected postretirement benefit funding costs, (3) study of Total Rewards, (4) compliance review of the Department of Health and Human Services' Early Retiree Reinsurance Program (ERRP), and (5) implementation of the benefit reviews. The documentation showed that $69,402 was expensed in 2008, $93,618 in 2009, $114,628 in 2010, and $88,567 for the period January through September 2011 for benefit review activities under Work Order 473401.

OPC witness Dismukes argued the expenses in Work Order 473401 relate to consulting funds for an outside benefits review that does not occur annually therefore the amount should be amortized over two years and $18,067 should be removed from the test year. Witness Dismukes also stated that some of the service company specific work orders should be removed from the test year because they lacked supporting details.

OPC argued that while Gulf's witness McMillan admitted that the benefit review for the 2011 Work Order does not take place each year, he stated that other benefit reviews are conducted on an as-needed basis through the years. OPC stated that witness McMillan's analysis did not identify the associated costs that are included in the test year and for that reason his argument fails.

The Parties agree that the benefit review in the 2011 Work Order does not occur every year. The facts presented regarding the benefit review activity covered in Work Order 473401 indicate that normal benefit review activity is not limited solely to the benefit reviews that occur every other year. Gulf's benefit review activity is varied and it has been performed by Southern Company's human resources management each year since February 2009.

We note that OPC witness Dismukes' recommendation and adjustment regarding the benefit review covered in the 2011 Work Order 473401 appears to be based primarily on the fact that the benefit review occurs every other year. Gulf argued that other normal benefit activities are ongoing and that the 2012 test year costs represents an ongoing level of benefit review activity. To support its argument, Gulf provided documentation showing that since February 2009, benefit review activities have been varied and conducted each year.

We find that the benefit review activities are varied and occur each year. Thus, we decline to require that the operating expenses be amortized over two years. As a result, no adjustment related to Work Order 473401 is warranted.

<u>Costs Related to Work Order 49SWCS</u>

We find that the costs related to Work Order 49SWCS for a biannual customer summit shall be amortized over two years. This results in a reduction to test year jurisdictional O&M of $19,450 ($20,130 system).

<u>Costs Related to Work Order 4Q51RC</u>

This issue addresses software and enhancements in Work Order 4Q51RC, and a formerly CWIP classified Work Order, W4QPA01, that Gulf asserts should be expensed. Gulf witness McMillan asserted that these work orders cover ongoing software costs associated with a new application necessary for managing the railcar maintenance program, and ongoing expenses related to control system integrity (CSI).

Witness McMillan testified that the railcar software system manages railroad and private repair shop maintenance invoices mandated by railroad standards for railcar use, and provides information to audit maintenance invoices, automate payments, and to provide repair histories for the railcar fleet. He argued that the charges for this system are related to necessary ongoing support and enhancements for the new software application. The charges are recurring and they are expensed because they did not meet the capitalization threshold. He further asserted that the CSI tool allows Gulf to manage and document the compliance requirements resulting from the NERC Cyber Security Standards and when the CSI tool is placed in service at the end of 2011, the depreciation expense will be billed to the Company and booked to expense in 2012.

Witness McMillan testified that the new software application for managing the railcar maintenance program is a third-party software package that was budgeted for 2012, which is the test year. Witness McMillan stated that the in-service date included in the 2011 budget was December 2011. He further stated that the anticipated in-service date has been moved beyond the 2012 test year and is now expected to be placed in-service in 2013. However, witness McMillan argued that while specific dollars are not expected to be expensed in the 2012 test year, the costs have been assigned to other activities covered in this work order that represent ongoing costs. He later clarified that the new system is budgeted to a fuel account related to fuel handling and the costs were not included in the fuel clause adjustment as he testified earlier. In a late-filed exhibit witness McMillan stated that since the costs were not recovered in the fuel clause, they are included in the Company's base rate request.

Gulf explained that the increase in the amount budgeted from 2011 to 2012 is primarily due to approximately $20,000 of railcar software enhancement maintenance expenditures being moved from Plant (rate base) to O&M (expense). The difference in the budgeted amounts for CSI from 2011 to 2012 are due to increased product rates for leased dedicated servers and personal computers, and the reclassification of expenses from CWIP to O&M expense.

OPC witness Dismukes testified that the Company's explanation for the increase in the expense amount from the 2011 to the 2012 budget was due to a formerly capitalized item for Work Order 4Q51RC and a formerly CWIP classified Work Order 4QPA01 being moved to expense. She asserted the Company failed to demonstrate why these costs should be expensed instead of capitalized and provided no evidence to show that these costs are recurring and should be included in test year expenses.

The items covered by the two work orders addressed in this issue are capitalized items that Gulf wants to move from plant to O&M expense. We find that the record supports Gulf's argument that the maintenance and enhancement costs for the software are ongoing and recurring.

We note that the in-service date for the new application for the railcar and CSI tool was December 2011 and the Company has now moved that date beyond the 2012 test year to 2013. We recognize that during the implementation stages of a project the targeted in-service date may change. We agree with Gulf that it is reasonable to expect that some expenses associated with a new application being ready to be placed in-service are ongoing.

We find the explanation and documentation provided by Gulf to be persuasive that the costs associated with the implementation of the new application are ongoing and shall remain in the 2012 expenses.

For the foregoing reasons, we find that the costs are ongoing and pertain to software maintenance and enhancements used to manage the railcar maintenance program and the CSI tool used to manage and document compliance requirements resulting from the NERC Cyber Security Standard. The costs included for the 2012 test year are reasonable and prudent and thus shall not be removed from operating expenses.

Public Relations Expenses Charged by SCS

Gulf witness McMillan testified that the expenses related to SCS Work Order 474401, relating to internal company publications and external public relations messages should not be removed from test year expenses. Gulf asserted that these internal publications involve educating employees about various industry, local, and Company issues, making its employees better equipped to serve its customers. Witness McMillan went on to explain that the external publications serve to inform Gulf's customers about billing, safety, and energy efficiency matters as well as to help coordinate with Gulf's other operating companies regarding sharing and not duplicating costs. Gulf testified that these external customer publications help its customers to find alternative ways to receive and pay bills, prevent accidental injuries, and use energy more efficiently which provides value to its customers.

OPC witness Dismukes testified that we have typically disallowed expenses that are public relations oriented, finding that they benefit stockholders, not customers. Witness Dismukes went on to assert that Gulf has failed to demonstrate that these activities benefit the customers in this case. OPC believes that these costs are based on image-enhancing activities and that test year expenses should be reduced by $17,482.

We disagree with OPC witness Dismukes' characterization of the costs associated with Work Order 474401 being exclusively beneficiary to shareholders. We find that based on the description of services provided by the Company for Work Order 474401, and the testimony provided by Gulf witnesses, the Company has supported these expenses. We further find that both the internal publications and external publications described by Gulf witness McMillan directly benefit Gulf's customers. As such, we find that no adjustment is necessary to remove public relations expenses charged by SCS associated with Work Order 474401.

Expenses in Work Orders 473ECO and 473ECS

Gulf witness McMillan asserted that Work Orders 473ECO and 473ECS cover functions that require legal work necessary to comply with rules, regulations, contracts and agreements, that ultimately benefits its ratepayers. The legal work is provided by the chief operating officer and external affairs office and the related expenses are budgeted in these work orders. Gulf clarified that Work Order 473ECS reflects the total external affairs expenses budgeted and the expenses incurred are actually charged to a number of specific orders that share in the overall budget.

Witness McMillan testified that legal advice is sought regarding many things, such as environmental laws and electric-related matters debated in Washington. The ratepayers benefit from the legal advice Gulf receives that ensures compliance with the laws and regulations affecting its operation. Witness McMillan asserted that everything Gulf does to ensure its business operates efficiently and cost-effectively is for the benefit of the ratepayers.

OPC witness Dismukes testified that Work Orders 473ECO and 473ECS relate to the chief operating officer and external affairs legal expenses and the Company has not clearly shown how these costs benefits ratepayers. She asserted that the expenses should not be included in the test year unless the Company can demonstrate how the services received from the expenses are beneficial to the ratepayers.

Gulf receives legal advice from the chief operating officer and the external affairs functions that are covered in Work Orders 473ECO and 473EC. We note that SCS, the service company, charges the expenses for the legal work provided to Gulf to the accounts set up in Work Order 473ECO and Work Order 473ECS. We recognize that the legal expenses budgeted in the work orders for the projected test year 2012 are $34,866, which is a $1,014 increase over the 2011 budgeted amount of $33,852.

We find that the legal fees for the Company are reasonable. We further find that the explanation and documentation provided support Gulf's assertion that the ratepayers indirectly benefits from the legal advice it receives. Based on the evidence presented, we find that the projected 2012 expenses of $33,690 ($34,866 system) are reasonable and prudent. Therefore, an adjustment to the operating expenses to remove the legal expenses is not warranted. SCS provides legal advice to Gulf and the other subsidiaries of the Southern Company. The expenses charged to Gulf are for legal work that Gulf receives to ensure compliance with rules and regulations affecting its operation that ultimately benefits ratepayers.

Expenses Related to Work Order 471501

Witness McMillan testified that investor relations works to preserve the value of Gulf's securities and to ensure continuous access to capital at favorable rates for the benefit of Gulf and its customers. Through Work Order 471501, the Company has an ongoing investor relations program with current and potential investors in system equity and debt securities that ensures that the Company's securities are fully valued by the investment community. Witness McMillan further argued that investor relations activities are essential for any company with publicly traded securities.

Witness McMillan stated that SCS works as Gulf's agent and interacts with individuals who are involved in the capital markets to ensure that Gulf has access to cost effective or adequate investment sources. Gulf's ratepayers benefit from SCS' interactions with individuals in the investment community that result in lower costs for Gulf's debt sales and adequate access to money necessary to capitalize the Company's business. Witness McMillan asserted that investor relations facilitates these benefits by answering questions potential investors have regarding investment securities.

Gulf indicated that $99,955 has been budgeted for investor relations general expenses for the 2012 test year through this work order. Documentation was provided that reflected that the Company expensed $87,502 in 2008, $71,923 in 2009, $85,066 in 2010 and $64,000 for the period of January through September 2011 for investor relations activities.

Gulf argued that the expenses related to this work order were included in the Company's last rate case and the 2012 test year amount is reasonable and prudent.

Witness Dismukes argued that the investor relations expenses are shareholders expenses that should be moved below-the-line for ratemaking purposes because they benefit the stockholders not the ratepayers. She asserted that we have removed shareholder costs in a prior rate case[30] and should continue its practice by removing the investor relations expenses of

[30] See Order No. PSC-96-1320-FOF-WS, issued October 30, 1996, in Docket No. 950495-WS, In re: Application for rate increase and increase in service availability charges by Southern States Utilities, Inc. for Orange-Osceola Utilities, Inc. in Osceola County, and in Bradford, Brevard, Charlotte, Citrus, Clay, Collier, Duval, Highlands, Lake, Lee, Marion, Martin, Nassau, Orange, Pasco, Putnam, Seminole, St. Johns, St. Lucie, Volusia, and Washington Counties.

Modified minimum filing requirements report of Quincy Telephone Company.

$96,851 from the 2012 test year. To support her assertion, witness Dismukes provided the following excerpt from Order No. PSC-96-1320-FOF-WS:

> Through the ROE leverage formula, we have allowed recovery of costs associated with being a publicly traded utility. Specifically, in the calculation of the appropriate cost of equity, we recognized an additional 25 basis points to the otherwise determined cost of equity to provide for these costs. To ask SSU's ratepayer to pay 25 basis points on ROE in addition to the amount requested by SSU would be duplicative. We also question whether the benefits SSU receives from MP&L are worth $208,776 to the ratepayers in Florida. Consequently, we shall disallow all of the utility's requested shareholder services expenses of $208,776.

Witness Dismukes further argued that a similar adjustment was appropriate in the instant case because investor relations expenses benefit shareholders as opposed to ratepayers. In its brief, OPC presented a new argument that companies are compensated for investor relations costs through the rate of return on equity.

Gulf's investor relations program is budgeted through Work Order 471501 and conducted by staff of SCS, a subsidiary of the Southern Company, that provides a variety of services to Gulf. The investor relations program is ongoing and requires interaction with current and potential investors to ensure that the Company's securities are fully valued by the investment community.

Documentation was provided showing the expenses the Company has incurred for investor relations activities for the years 2008, 2009, 2010, and January through September 2011. We find that investor relations benefits the ratepayers through the Company's access to capital at favorable rates. It is reasonable for a company with publicly traded securities to have an investor relations program and the Company shall be allowed to include the associated expenses above-the-line for ratemaking purposes. Based on the evidence presented, we find that both the stockholders and the ratepayers benefit from the investor relations program activities and the costs are reasonable and prudent.

We recognize that, on a case-by-case basis, we have allowed investor relations expenses in prior rate cases,[31] where the record showed that ratepayers benefited from these activities. We further note that we have disallowed these expenses in the rate case cited by OPC. We, however, find the circumstances in the case cited by OPC are sufficiently different from those presented by Gulf in this proceeding.

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[31] See Order Nos. PSC-04-0128-PAA-GU, issued February 9, 2004, in Docket No. 030569-GU, In re: Application for rate increase by City Gas Company of Florida; Order No. PSC-97-0618-FOF-WS, issued May 30, 1997, in Docket No. 960451-WS, In re: Application for rate increase in Duval, Nassau, and St. Johns Counties by United Water Florida Inc.; and Order No. PSC-94-0119-FOF-TL, issued February 1, 1994, in Docket No. 920195-TL, In re: Modified minimum filing requirements report of Quincy Telephone Company.

We note that in its brief, OPC raised the argument for the first time that companies are generally compensated for investor relations expenses through the rate of return on equity. However, OPC did not argue that Gulf has been compensated for its investor relations expenses in this case through the rate of return on equity, and the assertion is not supported by any evidence in the record.

For the foregoing reasons, no adjustment shall be made to operating expenses related to this matter. The stockholders and the ratepayers benefit from the investor relations program and the Company shall be allowed to include reasonable expenses in the 2012 test year.

Advertising Expenses

We find that the appropriate amount of advertising expenses for the 2012 projected test year is $1,132,000 ($1,132,000 system).

Deferred Compensation

Gulf offers an unfunded Deferred Compensation Plan (Plan) to its employees whose yearly earnings are $100,000 or more. The Plan allows eligible employees to defer earned income and certain taxes until a specific date or retirement. The Plan is subject to applicable provisions of the Employee Retirement Income Security Act of 1974.

Gulf witness Kilcoyne testified regarding the Company's deferred compensation plan, how the interest rate was determined, and why the interest should be included in the 2012 test year expenses. Witness Kilcoyne asserted that the participants, customers, and the Company benefit from the Plan. The Plan allows participants to exercise retirement and tax planning options and the Company to have the deferred funds available for other uses. The Plan offers a competitive compensation and benefit package to attract and help retain talented employees.

Witness Kilcoyne asserted that the deferred compensation interest is paid according to the Plan Prospectus and appropriately compensates the participants for the opportunity costs of the funds that are available to the Company in the form of working capital. She argued that this aspect of Gulf's compensation benefits customers by assisting Gulf in retaining and attracting qualified managerial employees.

She stated that Gulf pays a market interest rate on the deferred earnings to compensate the participants for the opportunity cost of deferring their income to a future date. The interest rate is established by the Plan Prospectus as the Prime Rate published monthly in the *Wall Street Journal*. Witness Kilcoyne argued that the budgeted interest rate was derived from Moody's Analytics 2010, Prime Rate, which was current at the time the 2012 budget was prepared. She asserted that the budgeted interest of $362,309 should not be removed because the participants should receive interest on their deferred compensation.

Gulf noted that the Deferred Compensation Plan consists of two investments: (1) the Prime Rate Equivalent, and (2) the Southern Company Stock Equivalent. Any gains or losses for Gulf's participants are recorded quarterly. Gulf provided information that reflected actual O&M

expenses for interest on deferred compensation at $52,507 for 2009, $276,409 for 2010, $121,192 for 2011, and a forecasted amount of $362,309 for test year 2012. A derivation of Other Employee Benefits was also provided showing the calculation for the deferred compensation interest projected for the 2012 test year. The Company also explained that the interest on deferred compensation increased by $85,900 primarily because of the Moody's Prime Rate of 6.78 percent, which was used for the 2012 projections, and to a lesser extent a 3 percent merit salary increase.

Witness Kilcoyne presented arguments regarding Gulf's at-risk and variable pay programs. As support for using at-risk and variable pay, she asserted that deferred compensation is a part of an overall compensation approach that is market competitive and necessary to attract and retain employees.

OPC witness Ramas stated that OPC asked Gulf to provide a breakdown of the projected 2012 Other Employee Benefits costs of $815,104, and to explain the increase above the test year amount. The response showed that the interest on deferred compensation in the amount of $362,309 is based on a 6.78 percent interest rate being applied to the 2012 year end balance of $5,343,788.

OPC witness Ramas argued the costs projected for the interest on deferred compensation are based on a generous rate and should be removed because the Company failed to justify why the costs should be included and why the interest rate should be 6.78 percent.

Gulf explained how the interest rate for the deferred compensation interest was determined, how the balance resulted, how the interest was calculated, and why the interest should be paid. We noted that the interest increased by $85,000 from 2010 to 2012 primarily as a result of the 6.78 percent rate used to calculate the interest on the deferred compensation balances.

We find that the Company shall be allowed to include interest sufficient to cover the opportunity cost of the deferred compensation. However, we agree with OPC that the 6.78 percent interest rate is somewhat high considering the 30-Year U.S. Treasury rate was 3.12 percent on November 10, 2011. Gulf testified that the 6.78 percent interest rate was derived from the May 2010 Moody's Analytics, which is now Moody's Economy.com. Our staff reviewed the May 2010 Blue Chips Financial Forecasts for Moody's Economy.com and calculated an average rate of 3.75 percent for the Second Quarter 2010 through the Third Quarter 2011. We note that the 6.78 percent rate was not in the May 2010 Blue Chip Forecast for Moody's Economy.com.

We find that the 30-Year U.S. Treasury rate of 3.12 percent on November 10, 2011, is the more appropriate interest rate for calculating the deferred compensation interest. The projected 2012 year end deferred compensation balance is $5,343,788. Applying the November 10, 2011 U.S. Treasury rate of 3.12 percent to this balance results in interest of $166,726 instead of the $362,309 that was proposed by the Company. Accordingly, we find that interest shall be reduced by $195,583, which is the difference between the $362,309 proposed by Gulf and the $166,726 based on the current estimate of the applicable interest rate.

Table 7

Interest on Deferred Compensation		
	Commission Calculation	Gulf's Calculation
Projected 2012 Year End Balance	$5,343,788	$5,343,788
Moody's Analytics 2012 Prime Rate	3.12%	6.78%
Adjusted Projected 2012 Deferred Compensation Interest Expense	$166,726	$362,309
Jurisdictional Amount	$163,390	$355,059

We find that the Company shall be allowed to include interest on the 2012 projected deferred compensation balance at a rate sufficient to cover the opportunity cost of the balance. Therefore, we further find that the interest be calculated based on the 30-Year U.S. Treasury rate of 3.12 percent on November 10, 2011. The calculation, shown in the table above, results in an adjusted jurisdictional deferred compensation of expense of $163,390. Therefore, interest on deferred compensation shall be reduced by $191,669 ($195,583 system).

SCS Early Retirement Costs

Gulf witness Kilcoyne testified that the charge for SCS Early Retirement is an expense specifically associated with the benefits provided to a closed group of former SCS employees who terminated early as part of early retirement initiatives, during the 1980s and 1990s, that were intended to lower overall SCS costs, including those attributable to Gulf's customers. Witness Kilcoyne stated that this expense is no different from the expense for other SCS benefit programs, and as such it should be included in the cost of service.

OPC witness Ramas testified that the Company only provided the monthly 2010 actual accrual for "SCS Early Retirement" of $4,195 and indicated that the same $50,340 annual amount was budgeted for 2012. Witness Ramas stated that "there is no further discussion regarding what the SCS Early Retirement accrual was for or why it should be passed on to Gulf's ratepayers." Witness Ramas recommended that the $50,340 amount be removed.

We agree with OPC that the SCS Early Retirement accrual of $50,340 should not be included in test year expenses. In response to OPC discovery, the Company stated that the 2010 monthly accrual was $4,195, or $50,340 annually, and no change was made for the budgeted amount for 2012. Witness Kilcoyne explained that the charge is for SCS employees who terminated early during the 1980s and 1990s and the intention was to lower overall SCS costs, including those attributable to Gulf's customers. The Company provided no additional information regarding how the early retirements lowered overall SCS costs or who exactly these employees were. Based on the foregoing, we find that removing $49,338 ($50,340 system) in SCS Early Retirement Costs from 2012 O&M expense is appropriate.

Executive Financial Planning Expenses

Executive Financial Planning Expenses shall not be included in operating expenses. Gulf identified \$48,000 (\$48,000 system) of executive financial planning expenses that Gulf agrees need to be removed from operating expenses and consequently reflected in the adjustments to NOI.

Increase to Average Salaries

Gulf included in its 2012 projected budget, base payroll costs of \$103,333,012, variable payroll costs of \$16,464,470, and fringe benefit costs of \$31,096,355 for total payroll and benefit costs of \$150,893,837. Witness McMillan testified that the work force included in Gulf's 2012 test year is 1,489 Full Time Equivalents (FTEs), which includes 159 additional FTEs. Witness McMillan explained that by year end 2010, due to extraordinary efforts to reduce costs and defer a rate case, Gulf's work force had declined to a level of 1,330 FTEs. Gulf contended that it proposed a very modest increase in average salaries for the 2012 test period. Gulf explained that MFR C-35 included a projected increase in average salary from 2010 to 2012 of only \$413 per employee, which equates to a total percentage increase in average salary over two years of only .005 percent.

Gulf witness Kilcoyne testified that OPC's recommended adjustments represent a 13.7 percent reduction in total compensation paid to Gulf's work force in 2012. Witness Kilcoyne explained that Gulf's projected total compensation for 2012 of \$119,797,482 and witness Ramas' proposed reductions would result in total compensation of \$103,333,012 or a 13.7 percent drop in projected 2012 compensation. Witness Kilcoyne stated that Gulf paid \$107,897,170 of compensation to its employees in 2010 and with witness Ramas' adjustments, Gulf's 2012 level of compensation would be lower than 2010, when Gulf had intentionally reduced its work force.

Gulf witness Wathen, a Director with Towers Watson, a professional services company that advises organizations on all aspects of their compensation programs, stated "Overall, our analysis indicates that Gulf's compensation programs are comparable to and competitive with market practices of other similarly sized utilities." Witness Wathen testified that the programs at Gulf fall well within market norms and are not excessive in design or level of pay. He stated that Gulf's compensation philosophy targets base salary and at-risk compensation at the 50th percentile of similarly sized utilities. Witness Wathen stated that Towers Watson examined the proxy disclosures for 19 publicly-traded utilities comparable in size to Southern Company and 13 utilities comparable in size to Gulf. Witness Wathen concluded that Gulf's total compensation philosophy aligns well with peer practices as a majority of the utility peers target the market 50th percentile for some or all pay elements. Witness Wathen testified that Gulf's Performance Pay Program design is comparable to and competitive with short-term at-risk compensation designs of the market perspectives examined and the Company's long-term at-risk compensation program design, reflecting annual grants of stock options and performance shares, to be competitive with the market perspectives examined.

OPC witness Ramas recommended a reduction of 91 employees to Gulf's projected increase in the number of employees of 159, which would result in a reduction to O&M payroll expense of $3,195,627. In addition, witness Ramas recommended eliminating all of the incentive compensation that is paid to Gulf's employees which would result in a reduction to O&M payroll expense of $12,623,632. Her recommendations are described in more detail below.

FIPUG agreed with OPC that these expenses should be reduced by $3,195,627 because in these difficult times, when many people in northwest Florida are out of work, these increases are out of step with economic reality.

Gulf's base payroll is projected to increase by $9,813,114 from 2010 ($93,519,898) to 2012 ($103,333,012). Approximately $7.8 million of the forecasted increase is due to the addition of 159 FTEs. The remaining $2 million increase in base payroll from 2010 through 2012 is a result of contractually-required general increases of base payroll for covered (union) employees of 2.25 percent in 2011 and 2.35 percent in 2012. Payroll increases in base payroll for non-covered employees was 2.5 percent (merit budget) in March 2011 and 2.5 percent (merit budget) in March 2012. None of Gulf's employees experienced a merit increase or general increase (union employees) in 2009. Variable payroll was projected to increase $2,087,198 from 2010 ($14,377,272) to 2012 ($16,464,470), of which $702,387 was due to Gulf' proposed additional 159 FTEs. The remaining increase in variable compensation between 2010 and 2012 was attributable to Gulf projecting that it will achieve better performance on the performance indicators for short term variable compensation than in 2010. Gulf stated that its performance under the performance measures used for variable compensation was lower than Gulf had typically achieved, therefore, Gulf forecasted an improvement in performance.

Witness Kilcoyne's explained that for Gulf overall, the average actual salary of $66,512 as of September 1, 2011 is 4.6 percent below the median market salary of $67,490, after the increases in base salaries described above. Therefore, we find that the general increases for covered employees and the merit increases for non-covered employees are reasonable. We address the increase of 159 FTEs from 2010 to 2012 and the variable or incentive compensation below.

<u>Increases to Employee Positions</u>

Gulf witness McMillan stated that Gulf's budget assumed a full work force complement for the test year. Witness McMillan explained that due to extraordinary efforts to reduce costs and defer a rate case, Gulf's work force had declined to a level of 1,330 FTE positions. He testified that the work force included in Gulf's 2012 test year was 1,489 employees and that over 95 percent (152 FTEs) are justified in the testimony of Gulf witnesses Neyman, Moore, Caldwell, and Grove.

Although we have made a hiring lag adjustment in Gulf's last rate case, witness McMillan testified that the Company believed a hiring lag adjustment was inappropriate for several reasons in the current case. He stated that such an adjustment assumed that if a position is not filled, the associated funds will not be spent and that a hiring lag adjustment assumed that labor costs should be looked at in isolation. Witness McMillan contended that resources can and will be redeployed from one budget category to another to meet customers' needs and it is therefore unlikely that any funds available from unfilled positions would result in lower total O&M expense.

Gulf witness Neyman stated that Gulf had 193 FTEs in Customer Accounts at the end of 2010 and there are 200 FTEs budgeted in the Customer Accounts function for 2012, resulting in a net increase of 7 FTEs. Witness Neyman explained that there was a decrease of 18 FTEs as a result of efficiencies gained by implementing the Advanced Metering Infrastructure (AMI) initiative. In addition to the 18 FTEs eliminated, 9 contractor positions were also eliminated that were not included in the FTE numbers. Witness Neyman explained, offsetting these reductions were increases in FTEs due to 6 vacancies at the end of 2010 and 19 new positions in the Customer Service Center (CSC). Witness Neyman testified that 16 of the 19 FTEs are customer service representatives in the CSC and 3 of the FTEs are for a supervisor, administrative assistant and quality assurance analyst to support the additional customer service representatives. Witness Neyman explained that Gulf's service level goal is to answer 80 percent of customers' calls within 30 seconds and that this goal was not met in 2009 or 2010. Witness Neyman stated that currently four of the 19 positions remain vacant.

Gulf witness Neyman stated that there are 128 FTEs included in Gulf's Customer Service and Information (CS&I) budget in 2012, and that Gulf had 93 FTEs included in CS&I at the end of 2010. Gulf, therefore, had included an increase of 35 FTEs in its 2012 budget as compared to the end of 2010. Witness Neyman testified that the net increase of 35 FTEs in CS&I can be categorized in three areas: Demand-side Management (DSM), vacancies, and new positions. She stated that 28 of the 35 FTEs are attributable to the recent DSM Plan filed by Gulf and approved by us in Docket No. 100154-EG, via Order No. PSC-11-0114-PAA-EG. Witness Neyman explained that of the 28 FTEs, the costs associated with 26.5 FTEs will be recovered through the ECCR clause. The costs associated with 1.5 of the FTEs are in the O&M budget. Witness Neyman stated 4 of the additional FTEs are necessary and support the Company's activities in Forecasting, Mass Markets, and Lighting and the costs are split with 1 FTE budgeted to ECCR and 3 to O&M. Witness Neyman explained that the remaining 3 FTEs are for new positions to support Gulf's customers in the areas of lighting and electric vehicles. She stated that 1 is budgeted for capital expenditures and the other 2 are in the O&M budget. She stated that all the positions in Gulf's CS&I are filled.

Gulf witness Moore testified the Distribution department increased its employee complement from 358 FTEs in December 2010 to 403 budgeted FTEs for 2012, or an increase of 45 FTEs. Witness Moore explained that these 45 positions are entry level positions, and they consist of 32 Utility persons, 10 Engineers in Training (EITs), and 3 Fleet positions. He stated that 36 of the 45 FTEs are for vacancies existing at the end of 2010 and 9 FTEs are new positions. Witness Moore explained that there were so many unfilled positions at the end of 2010 because Gulf was making every effort to keep expenditures low in an attempt to avoid a base rate proceeding from 2008 through 2010 and there was an unusually high turnover of Distribution employees during 2010 with 12 engineering positions leaving Gulf. Witness Moore stated that the 10 entry level EITs have been filled. Witness Moore explained that the 32 Utility person positions go through a thorough training program and it is not uncommon to lose some of the new entries in the program. He stated that because of the length of the program, usually 7 years from Apprentice to top-level Journeyman classification, Gulf has increased the line services positions to ensure an adequate number of qualified Journeyman Line Technicians. Witness Moore stated that the 3 additional budgeted Fleet positions consist of 2 mechanics and 1 administrative assistant.

Gulf witness Caldwell testified that Gulf's Transmission work force was projected to grow by 13 positions from the end of the 2010 level of 92 FTEs to the 2012 test year level of 105 FTEs. Witness Caldwell explained that the Company performed an organizational study and restructured Transmission to better align the departments, improve management of the construction program, and enhance the ability to maintain the transmission facilities. Witness Caldwell stated that at the end of 2010, Transmission had 8 FTE vacancies which included 1 new position, Security Coordinator, which had been approved but not yet filled. He stated that of the remaining 7 vacancies, 3 were on hold pending reorganization, and 4 vacancies were due to attrition. The 2012 Transmission budget assumed that all of these vacancies will be filled in 2012. Witness Caldwell testified that the 2012 budget also included 5 new positions to address right-of-way issues and the Transmission construction program.

Gulf witness Grove testified that, at the end of 2010, Gulf had 342 FTEs in the Production function. For purposes of the test year, Gulf budgeted labor costs equivalent to 394 FTEs. Witness Grove stated that at Plant Crist, there were 15 vacancies at the end of 2010 as well as 5 new positions. Witness Grove stated that 7 of the Plant Crist positions will either be charged to capital projects or the ECCR and that it is Gulf's intent to fill all 20 positions.

Witness Grove stated that there were 23 vacancies at Plant Smith at the end of 2010 and that all are included in Gulf's 2012 O&M budget. He stated that Gulf had filled or is in the process of filling all except 2 vacancies. Witness Grove explained that 8 of the 23 positions are for entry-level Utility persons.

Witness Grove stated that there were 26 filled positions at Plant Scholz and in 2012 Gulf had budgeted a full complement or 34 positions. Witness Grove testified that, due to uncertainty with environmental regulations, Gulf had chosen not to fill 8 positions until there is more clarity about prospective environmental regulations. He stated that at the end of 2010 there was also 1 vacant position, the Renewable Energy Manager, at the Power Generation Office. Witness Grove testified that by December 31, 2011, Gulf expected to fill 42 of the 52 positions. Gulf's current budget projects a net increase of 42 positions from year end 2010, or a reduction of 10 positions from the 2011 budget cycle estimate. He stated that the labor dollars for those 10 FTEs have been redirected to contract labor due to the pending environmental regulations.

OPC witness Ramas stated that it is not reasonable to assume that 100 percent of the budgeted employee positions will be filled by the start of the 2012 test year and that the level will be maintained throughout the test year. Witness Ramas testified that it is not the norm for a company to experience a 0 percent vacancy rate and to have filled its full budgeted employee complement for any given month, let alone an entire year. She stated that for the nine-year period 2002 through 2010, the average vacancy factor was 5.1 percent and that over the last five years, 2006 through 2010, the average vacancy factor was 6.1 percent. Witness Ramas stated that Gulf had projected that its employee complement will increase by 159 employees from 1,330 as of December 31, 2010 to 1,489 employees before the start of the test year. Witness Ramas added that the employee count increased by 33 employees to 1,365 as of June 30, 2011 and that is still 124 employees below the budgeted level of 1,489.

OPC witness Ramas recommended that Gulf's proposed increase of 159 employees from the actual December 31, 2010 level be reduced by 91 positions, thereby allowing 68 additional positions, or 42.8 percent of the proposed employee increase level. She stated that this would allow for the inclusion in the projected test year costs of 1,398 employees, which is 33 additional employees above the actual June 30, 2011 or 68 additional employees above the December 31, 2010 level of 1,330. Witness Ramas explained that she applied the average vacancy factor actually experienced by Gulf during the five-year period 2006 through 2010 of 6.1 percent to Gulf's budgeted 2012 test year employee complement of 1,489, resulting in a recommended test year employee complement of 1,398 employees or 68 above the actual December 31, 2010 employee level, 33 of which have already been filled as of June 30, 2011. As noted above, witness Ramas' recommended increase of 68 employees represents 42.8 percent of the Company's requested increase in employees of 159. Witness Ramas applied the 42.8 percent to the Company's total increase in expenses of $5,586,761 to arrive at a recommended increase in labor costs of $2,391,134. Witness Ramas' recommended reduction in test year labor costs was $3,195,627 ($5,586,761 less $2,391,134).

FEA witness Meyer stated that he believed that Gulf's annualized payroll (including benefits) should be reduced by approximately $5.2 million. Witness Meyer explained that, in Gulf's last rate case, Gulf requested 1,367 FTEs but that Gulf had not operated at 1,367 employees in any year over the past decade. Witness Meyer stated that at the end of March 31, 2011, Gulf employed 1,334 employees and at the end of June 30, 2011, Gulf employed 1,365 employees. Witness Meyer stated that he believed Gulf's annualized payroll expense should be based on Gulf's latest known level of employees of 1,365. Witness Meyer provided a summary of the increased number of employees which showed that 73 employees are related to recovery clauses and capital costs while the remaining 86 employees are related to O&M. Witness Meyer assumed that all growth from December 31, 2010 (1,330 employees) to June 30, 2011 (1,365 employees) or 35 employees would be assigned to the O&M function. He then multiplied the 51 unfilled position (86 less 35) by Gulf's 2012 average employee budgeted wage and benefit level of $101,339 to arrive at his $5.2 million adjustment.

FEA modified its recommendation based on evidence produced by Gulf, which listed Gulf's FTEs as of December 12, 2011, for the Production, Transmission, and Distribution functions. FEA stated that Exhibit 217 showed that Gulf was 40 FTEs under its 2012 budgeted increase in employees of 159. In addition, FEA pointed out that witness Neyman testified that she still had 4 unfilled service center employee positions. FEA recommended that we adjust Gulf's proposed level of labor expenses to reflect the 44 unfilled positions. FEA explained that the average cost of new employee's wages and benefits presented in witness Ramas' testimony was $60,800. FEA explained that by applying the $60,800 to the 44 unfilled positions and adjusting out the cost for clauses and capital cost (37 percent of the total cost), resulted in an expense adjustment of $1,685,376. FEA also stated that if Gulf can demonstrate that the 10 positions transferred to Production contract labor decreased its original labor expense adjustment, included in its rate case, then it would recommend an adjustment of $1.3 million based on 34 unfilled positions.

FIPUG agreed with OPC that these expenses should be reduced by $3,195,627 because in these difficult economic times, when many people in northwest Florida are out of work, these increases are out of step with economic reality.

FRF stated that Gulf had overstated the number of employees for the 2012 test year and accordingly had overstated labor expenses and, therefore, we should reduce Gulf's 2012 test year expenses by $3,195,627.

Witness McMillan testified that, as of September 30, 2011, Gulf had an employee complement of 1,391 FTEs. Witness McMillan explained that 27 of the 159 positions had not been filled by the middle of October, which included 10 positions at Gulf's power plants that have been eliminated in the final 2012 budget and replaced by an increased allowance for contract labor. Gulf produced information which reported actual FTEs as of December 12, 2011, for Production, Transmission, and Distribution and revealed 25 unfilled positions in the Production function, 3 unfilled positions in the Transmission function, and 12 unfilled positions in the Distribution function for a total of 40 unfilled positions. Exhibit 217 also reported current 2012 budget FTEs that showed 10 FTEs less in the Production function. However, as explained by witness Grove, the current 2012 budget moved these 10 FTEs to contract labor due to pending environmental regulations. As stated by witness Neyman, there are 4 unfilled positions in the Customer Service Center which results in a total of 44 unfilled positions.

Witness McMillan provided a hiring lag adjustment based on the estimated employee turnover during the year, times the average time it takes to fill a vacant position, times the average salary. Witness McMillan stated that the calculation of average employee turnover and the time required to fill these positions, by employee classification, was based on data for 2008 through 2010. Witness McMillan further explained that the average salary is based on actual 2011 salaries by employee classification. Witness McMillan's hiring lag adjustment is $448,069 or $439,149 after applying a jurisdictional factor as agreed to by witness McMillan. We find that, at a minimum, the $439,149 reduction shall be made in the instant case to payroll expense. We note that in Gulf's last rate case, Order No. PSC-02-0787-FOF-EI, a hiring lag adjustment of $323,635 ($330,628 system) was made to reduce O&M expense.

We find that it is appropriate to make an adjustment to payroll expense based on the latest actual FTEs as of December 12, 2011. As explained above, at the hearing Gulf produced information showing 40 unfilled positions as of December 12, 2011, when compared to the FTEs in the 2012 test year MFRs for the Production, Transmission, and Distribution functions. Thus, we shall include the 4 unfilled positions in the Customer Service Center for a total of 44 unfilled positions. It is not appropriate to look at the FTEs in the current 2012 budget which reflected 10 Production FTEs moved to contract labor. We find that all the changes in all the accounts would have to be examined in an updated budget. The FTEs that are included in the 2012 budget and

MFRs shall be the FTEs that are used to determine the appropriate number of employees to be included in the test year. The 44 unfilled positions are demonstrated below:

Table 8

Comparison of 2012 Budgeted Employee Increases to December 12, 2011 Employee			
Function	2012 Budget	12/12/11	Unfilled Positions
Customer Accounts	7	3	4
Customer Service and Information	35	35	0
Distribution	45	33	12
Transmission	13	10	3
Production	52	27	25
Corporate Support	7	7	0
Total	159	115	44

The Company has a documented history of the actual number of employees being below the budgeted average number of employees for each year 2002 through 2010 as demonstrated in witness Ramas' Schedule C-3, p. 2 of 2. We find, therefore, that the likelihood of the actual number of employees for 2012 being below the budget level of 1,489 employees is extremely high. The average percentage that the actual number of employees have been below the average budgeted number of employees was 5.1 percent for the period 2002 through 2009. Applying the 5.1 percent to the 2012 budgeted number of FTEs of 1,489, results in a difference of 75 employees between the actual and budgeted number of FTEs for 2012. We find that its recommended reduction of 44 employees is, therefore, conservative.

Based on the foregoing, we find that an increase of 115 FTEs shall be included in the 2012 test period, which is 44 less than the Company's requested increase of 159 FTEs. The level of employees of 115 FTEs represents 72.33 percent of the Company's requested 159 FTEs. We used a 27.67 percent (44/159) reduction factor in determining the adjustment as follows:

Table 9

Employee Increase Adjustment			
Description	Amount	Employee Adjustment Factor (44/159)	Approved O&M Expense Reduction
Base Payroll	$4,387,785	27.67%	$1,214,230
Medical and Other Group Insurance	$956,289	27.67%	264,633
Employee Savings Plan	$242,687	27.67%	67,159

Description	Amount	Employee Adjustment Factor (44/159)	Approved O&M Expense Reduction
Total included in 2012 O&M expense	$5,586,761	27.67%	$1,546,022
Jurisdictional Factor	-----	-----	0.9800918
Jurisdictional Reduction to O&M expense	-----	-----	$1,515,243

Based on the discussion above, we find that a reduction in O&M expense of $1,515,243 ($1,546,022 system) which reflects a decrease of 44 employees from Gulf's 2012 budgeted increase of 159 employees is appropriate. The $1,515,243 reduction to O&M expense, therefore, is based on a 115 employee increase rather than the Company's requested 159 employee increase from 2010 to 2012.

Incentive Compensation

Gulf witness McMillan included $16,464,470 in variable payroll in MFR Schedule C-35 which represents incentive compensation included in the 2012 test year. The $16,464,470 consisted of the following programs:

Table 10

Gulf's Incentive Compensation Programs and 2012 Amounts		
Incentive Compensation Program	2012 Amounts	Percentage
Performance Pay Program	$13,632,643	82.80%
Stock Option Expense	724,990	4.40%
Performance Share Program	1,097,321	6.67%
Performance Dividend Program	1,007,516	6.12%
Cash/Spot Awards	2,000	0.01%
Total	$16,464,470	100.00%

Gulf witness Wathen, stated that overall, our analysis indicates that Gulf's compensation programs are comparable to and competitive with market practices of other similarly sized utilities. Witness Wathen testified that the programs at Gulf fall well within market norms and are not excessive in design or level of pay. He stated that Gulf's compensation philosophy targets base salary and at-risk compensation at the 50th percentile of similarly sized utilities. Witness Wathen stated that Towers Watson examined the proxy disclosures for 19 publicly-traded utilities comparable in size to Southern Company and 13 publicly-traded utilities comparable in size to Gulf. Witness Wathen concluded that Gulf's total compensation philosophy aligns well with peer practices as a majority of the utility peers target the market 50th percentile for some or all pay elements. Witness Wathen testified that Gulf's Performance Pay

Program design is comparable to and competitive with short-term at-risk compensation designs of the market perspectives examined and the Company's long-term at-risk compensation program design. Gulf's annual grants of stock options and performance shares is competitive with the market perspectives examined.

In contrast, OPC witness Ramas recommended that 100 percent of the incentive compensation be disallowed and funded by shareholders, resulting in Gulf's adjusted test year expenses being reduced by $12,623,632 and plant in service being reduced by $1,217,206. In addition, witness Ramas reduced depreciation expense and accumulated depreciation each by $42,967. OPC also recommended that test year costs be reduced an additional $2,259,624 to remove the stock based compensation allocated to Gulf by SCS.

Witness Ramas testified that, in Order No. PSC-10-0131-FOF-EI, we disallowed PEF's incentive compensation plan costs, and stated that incentive compensation provided no benefit to the ratepayers.[32] Witness Ramas also stated that in Order No. PSC-09-0283-FOF-EI, we ruled that incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent company TECO energy. Witness Ramas explained that we disallowed the portion of the incentive compensation that was tied to the parent company's results. OPC also pointed out that in Order No. PSC-10-0153-FOF-EI, we found that FPL's executive incentive compensation was designed to benefit the value of shares and that incentive compensation payments effectively became base salary because FPL consistently achieved 30 to 40 percent above baseline year after year. As a result, we reduced the amount of executive incentive compensation borne by customers.

OPC witness Ramas' proposed elimination of incentive compensation includes both the Performance Pay Program, which is short-term in nature and available to all full-time employees, and long-term programs, consisting of the Stock Option Program, Performance Share Program, and the Performance Dividend Program. The long-term programs are only for Pay Grade 7 employees and above. In addition, there are Cash/Spot Awards for Call Center personnel that meet AllConnect transfer goals. As shown in Table 10 above, the bulk of the incentive compensation consists of the Performance Pay Program in the amount of $13,632,643 or 82.8 percent of the total amount of $16,464,470. The long-term incentive compensation programs total $2,829,827 or 17.19 percent for the 2012 test year, which include the Stock Option Program ($724,990), the Performance Share Program ($1,097,321), and the Performance Dividend Program ($1,007,516).

OPC asserted that, for the PPP program, overall company performance is tied two-thirds to financial goals and one-third to operational goals and by designing the PPP program to emphasize company financial goals, Gulf has possibly created an incentive to management level employees to focus on achieving the financial goals of the company without sufficient incentives to maintain a proper focus upon achieving operational goals. OPC noted that the operational employees do not have nearly as much incentive compensation at risk as do the management

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

level employees and that the individual decisions of non-management operational employees do not have that great of an individual effect on achieving financial goals.

OPC also explained that while it is recommending that Southern Company shareholders pay for the incentive pay programs, OPC is not advocating that incentive compensation be reduced or eliminated. Nowhere in the testimony of witness Ramas did she advocate that Gulf should stop paying incentive compensation.

Gulf witness Kilcoyne stated several reasons why she disagreed with witness Ramas' recommended disallowance. Witness Kilcoyne pointed out that witness Ramas did not consider whether Gulf's compensation plan is competitive and successful in retaining existing employees and attracting new employees. Witness Kilcoyne stated that witness Ramas' recommendation to disallow every dollar of "at-risk" or variable compensation is based on her mistaken belief that Gulf's at-risk compensation is designed to benefit only shareholders. Witness Kilcoyne contended that Gulf's compensation plan benefits customers as well as shareholders and that witness Ramas did not appear to realize the adverse impact her compensation adjustments would have on Gulf's ability to succeed in retaining and attracting qualified employees. Witness Kilcoyne stated that witness Ramas' adjustments imply that she may not understand the desirability of having performance based compensation and that witness Ramas did not address the serious consequences of her recommended adjustments. Finally, witness Kilcoyne believed that witness Ramas' disallowance of variable compensation is at odds with our prior practice.

Gulf witness Kilcoyne argued that the three goals used to measure performance all benefit Gulf's ratepayers. Witness Kilcoyne contended that Gulf earning a fair rate of return on equity helps maintain the Company's financial integrity, which, in turn, helps Gulf access capital markets to raise capital at a lower cost. Witness Kilcoyne argued that Gulf's trigger for the variable compensation plan, that Southern Company earnings must exceed the prior year's dividends, is not used to benefit shareholders, but to assure there are funds available to maintain customer operations. Witness Kilcoyne stated that this trigger gives management the discretion to meet the immediate needs of customers and investors before providing variable compensation. Witness Kilcoyne took issue with witness Ramas' statement that "the large emphasis on equity and earnings could shift focus away from operations in order to help the Company achieve its earnings targets," and stated that there is no data to support that assertion.

Gulf witness Kilcoyne also did not agree with witness Ramas' characterization of variable compensations as extra pay. Witness Kilcoyne stated that it is one component of an overall total compensation program, and at Gulf, all employees have compensation at-risk. Witness Kilcoyne testified that Gulf's average salary would decline more than $11,000 from 2010 levels if incentive compensation was totally eliminated.

Gulf witness Deason stated that at-risk compensation costs are currently being recovered in Gulf's rates. Witness Deason stated that witness Ramas' recommendation to disallow at-risk compensation costs are inconsistent with sound regulatory policy and basic principles of ratemaking, are contrary to our precedent, are based on simplistic assumptions that are not factually correct, and, if accepted, would be detrimental to the long term interests of Gulf's customers. Witness Deason argued that witness Ramas made no allegations nor presented any evidence that the overall compensation paid to Gulf employees is unnecessary or unreasonable. Witness Deason stated that witness Ramas' recommendation is further flawed because she made no analysis of the reasonableness of the net amount of compensation that remained after at-risk compensation is eliminated. Witness Deason concluded that witness Ramas' testimony is totally devoid of any consideration of reasonableness regarding either the overall amount of compensation or of the net amount that witness Ramas has recommended.

Witness Deason stated that in two previous Gulf rate cases, cost recovery for at-risk compensation was allowed and that a prior Florida Power Corporation rate case also provided for cost recovery of incentive (at-risk) compensation. Witness Deason added that, in a TECO rate case, we found that TECO's total compensation package was set near the median level of benchmarked compensation and allowed recovery of incentive compensation that was directly tied to results of TECO. Witness Deason argued that witness Ramas' analysis is flawed because no attempt was made to compare the total compensation paid to Gulf executives or employees to the market for similar services, duties, activities and responsibilities. Witness Deason contended that the focus of any disallowance should be how much is paid, not how it is paid. Witness Deason stated that a compensation structure that pays employees regardless of performance diminishes managements' leverage to motivate and focus employees on appropriate goals.

Gulf witness Deason testified that accepting witness Ramas' recommendation would require Gulf to either renege on its obligations to employees or deny Gulf a reasonable opportunity to earn its authorized rate of return. Witness Deason stated that a Utility earning a reasonable profit is beneficial for both its shareholders and its customers and, therefore, financial goals used to establish compensation levels are also beneficial to customers. Witness Deason contended that we at no time have denied cost recovery of 100 percent of at-risk compensation.

We note that both Gulf and OPC made valid points with regard to incentive compensation. We recognize that the financial incentives that Gulf employs as part of its incentive compensation plans may benefit ratepayers if they result in Gulf having a healthy financial position that allows the Company to raise funds at a lower cost than it otherwise could. There is validity in having incentive compensation more closely aligned with the Company's operations rather than Southern Company's financial position. In response to a question from the bench about the incentive programs being tied to Southern Company stock performance and whether Gulf's customers would get an additional benefit if Gulf's performance measures were incorporated into these programs, witness Kilcoyne answered that Gulf would have to look at that since its stock is wholly-owned by Southern Company and Gulf had never analyzed this issue in that manner.

We find that the short-term incentive compensation test year amounts related to the PPP shall be included in O&M expense, but the test year amounts related to the long-term incentive compensation plans shall be disallowed for ratemaking purposes. Gulf's long-term incentive compensation plans are designed to benefit Gulf's 119 employees in management that are Pay Grade 7 and above and are exclusively tied to financial goals of Southern Company. The short-term PPP is based on performance measures that are the same for all Gulf employees, though the awards differ depending on the category of employment, as described previously. We note that excluding long-term incentive compensation would be similar to our treatment of incentive compensation in TECO's and FPL's last rate cases. In Order No. PSC-09-0283-FOF-EI, it was determined that the incentive compensation should be directly tied to the results of TECO and not to the interests of its parent company, TECO Energy. In Order No. PSC-10-0153-FOF-EI, we eliminated 100 percent of FPL's executive incentive compensation.

Gulf's recommended PPP incentive compensation expense is based on a total Goal Factor of 125 percent for the 2012 budget and is calculated in the following manner:

Table 11

Total Goal Factor for the Performance Pay Program

Gulf's assumptions and calculations		
Operational Goals (1/3 weight)	50.00%	(1/3 x 150%)
Gulf Return on Equity (1/3 weight)	41.67%	(1/3 x 125%)
Southern Company EPS goal (1/3 weight)	33.33%	(1/3 x 100%)
Total Goal Factor	125.00%	

Though one-third of the PPP Total Goal Factor relies on Southern Company's earnings per share, it is appropriate to recognize some benefit to the ratepayers for Southern Company maintaining a healthy financial position. Including Gulf's return on equity rather than Southern Company's will have an even more direct affect on employee performance. Since all of Gulf's employees participate in the PPP program, it has a more direct impact on the operations and well-being of the Company. In contrast, the long-term incentive programs are more narrow in focus as they only apply to Pay Grades 7 and above which affects only 119 employees out of 1,379 (as of September 2011) and are tied to the stock price of Southern Company or Shareholder Return Goals of Southern Company only. We find that it is appropriate to exclude a portion ($122,229) of the PPP incentive program cost for 2012 based on the exclusion of 44 out of the 159 FTE increases (27.67 percent), as discussed above. Removing $122,229 in PPP costs results in an estimated reduction in payroll taxes of $9,187 ($9,351 system).

The approved adjustment is calculated as follows:

Table 12

Breakdown of the 2012 Net Incentive Compensation Amounts

Description	Net Amount in the Test Year	Percentage
O&M	$12,395,942	78.11
Capital	2,978,595	18.77
Clearing	494,979	3.12
Total	$15,869,516	100.00

Table 13

Incentive Compensation Adjustment by Program

	Incentive Amounts Subject to Removal
Performance Pay Program	$122,229
Stock Option Expense	724,990
Performance Share Program	1,097,321
Performance Dividend Program	1,007,516
Total	$2,952,056

Table 14

Breakdown of Incentive Compensation Adjustment

Description	Percentage Applied	Incentive Amounts by Category
O&M	78.11	$2,305,900
Capital	18.77	554,080
Clearing	3.12	92,076
Total	100.00	$2,952,056

Table 15

Allocation of Clearing Amounts Between O&M and Capital

Clearing Amounts ($2,952,056 times 3.12 percent)	$92,076
Percentage charged to O&M	46%
Clearing Amount Charged to O&M	$42,355
Clearing Amounts	$92,076
Percentage charged to Capital	54%
Clearing Amount Charged to Capital	$49,721
Comm. O&M Adjustment ($2,305,900 + $42,355 system)	$2,348,255
Comm. Jurisdictional O&M Adjustment ($2,348,255 x 0.9800918)	$2,301,505

We find that $2,301,505 ($2,348,255 system) in incentive compensation shall be removed from O&M expense as shown above.

After removing the long-term incentive pay, salaries for Pay Grades 7 and above are still within a reasonable range. Based on witness Kilcoyne' testimony regarding the External Market Analysis as of September 2011, page 1 of 2, the average target salary for Pay Grade 7 and above including base salary plus only the short-term incentive compensation is $159,105 which is 5 percent above the median market of $151,582.

Comparing the $159,105 target base salary plus short-term incentive compensation to the market salary including the market median base plus the short-term median target and long-term median target compensation of $169,076 shows that the $159,105 salary is only 5.9 percent below the median market target. In comparison, the evidence shows Gulf's Covered employees' target salaries are 7.5 percent below the median market salary and Gulf's employees in Pay Grades 1 through 6 target salaries are 3.5 percent below the median market salaries. Even after removing the long-term compensation from the employees in Pay Grades 7 and above, these employees' salaries will still be at a reasonable level as compared to other Gulf employees' salaries and to the median market salaries.

We find that OPC's recommended adjustment to exclude all incentive compensation is unreasonable and, as Gulf witness Kilcoyne stated, would result in an average salary below 2010 levels. Excluding all of the short-term incentive compensation along with the long-term compensation would put all of Gulf's employees target salaries well below the median market salaries (base plus short-term incentive compensation), including a negative 6.2 percent for nonexempt, noncovered jobs, a negative 12 percent for covered union jobs, a negative 13.2 percent for exempt jobs (Pay Grades 1-6), and a negative 19.2 percent for management, Pay Grade 7 and above. Moreover, excluding both short-term and long-term incentive compensation would result in Gulf's Pay Grade 7 and above target salaries being in a negative 27.6 percent position as compared to median market salaries (base plus short-term and long-term incentive compensation).

Removal of the $2,952,056 gross incentive compensation adjustment shown above from Gulf's gross total payroll amount of $119,797,482 will result in a total payroll amount of $116,845,426. Dividing the $116,845,426 by the number of employees noted above in the amount of 1,445, results in an average gross salary of $80,862, which is still above Gulf's gross average salary of $80,455.

OPC also recommended that test year costs be reduced an additional $2,259,624 to remove the stock based compensation allocated to Gulf by SCS. We agree that these stock based compensation amounts shall also be removed to be consistent with the long-term incentive compensation adjustment approved herein. Accordingly, we find that removing $18,961 related to working capital, $657,500 related to capital costs, and $1,554,547 related to the stock based compensation allocated to Gulf by SCS included in O&M expense, is appropriate. The impact of removing these costs, along with the previously discussed reductions in incentive compensation results in the following O&M and related adjustments:

Table 16

Breakdown of Incentive Compensation Adjustment

Reduction in O&M expense	
O&M Adjustment to Incentive compensation	$2,348,255
Jurisdictional Factor	0.9800918
Jurisdictional O&M Adjustment	$2,301,505
Stock Based Compensation allocated by SCS to O&M	$1,544,547
Jurisdictional Factor	0.9800918
Jurisdictional O&M Adjustment	$1,523,599
Stock Based compensation allocated from SCS	$657,500

Breakdown of Incentive Compensation Adjustment

Total Adjustment to Capital	$657,500
Reduction in Plant at 50%	$328,750
Jurisdictional Factor	0.9788452
Jurisdictional Plant-in Service Adjustment	$321,795
Related Depreciation Expense	$328,750
Average Test Year Depreciation rate	3.53%
Depreciation expense	$11,605
Jurisdictional Factor	0.9798128
Jurisdictional Depreciation Adjustment	$11,371
Reduction to Accumulated Depreciation	$11,605
Jurisdictional Factor	0.9770686
Jurisdictional Accumulated Depreciation Adjustment	$11,339
Reduction in PPP Costs	$122,229
FICA Employee Tax Rate	7.65%
Reduction in Payroll Taxes	$9,351
Jurisdictional Factor	0.9824645
Jurisdictional Payroll Taxes Adjustment	$9,187

In summary, we find that long-term incentive compensation and a portion of the PPP short-term incentive compensation shall be removed in the amount of $2,301,505 ($2,348,255 system) which results in $10,070,813 ($10,275,377 system) of incentive compensation being included in operating expenses. In addition, O&M expense related to stock based compensation of $1,523,599 ($1,554,547 system) shall also be removed. Based on our approval of Gulf's Incentive Compensation above, related reductions to plant in service of $321,795 ($328,750 system), accumulated depreciation of $11,339 ($11,605 system), depreciation expense of $11,371 ($11,605 system), and payroll taxes of $9,187 (9,351 system) shall be made. Therefore, related reductions to plant in service of $321,795 ($328,750 system), accumulated depreciation of $19,148 ($19,598 system), depreciation expense of $19,202 ($19,598 system) and payroll taxes of $9,187 ($9,351 system) shall be made.

Therefore, based on our decisions herein, the amount of Gulf's proposed Incentive Compensation expenses that shall be included in operating expenses is $10,070,813 ($10,275,377 system), which is $2,301,505 ($2,348,255 system) less than Gulf's requested jurisdictional amount of Incentive Compensation included in O&M expense of $12,372,318 ($12,623,632 system). In addition, O&M expense related to stock based compensation of $1,523,599 ($1,554,547 system) should be removed. Related reductions to plant in service of $321,795 ($328,750 system), accumulated depreciation of $19,148 ($19,598 system), depreciation expense of $19,202 ($19,598 system), and payroll taxes of $9,187 ($9,351 system) shall be made.

Employee Benefit Expenses

The merits of this matter have been discussed in detail above and we find that no further adjustments are warranted. Any adjustments approved by us have been made and discussed above and no further adjustments are necessary.

Other Post Employment Benefits Expense

We find that the appropriate amount of Other Post Employment Benefits Expense is $3,759,786 ($3,840,710 system).

Salaries and Employee Benefits

Based upon our adjustments as discussed above, the appropriate amount of Gulf's requested level of Salaries and Employee Benefits for the 2012 projected test year is $104,570,479 ($106,695,530 system). The following is a summary of the approved adjustments to Salaries and Benefits by subject matter:

Table 17

Approved Adjustments to Salaries and Benefits Expense		
Description	System	Jurisdictional
Company Salaries and Benefits	$112,438,277	$110,199,833
Interest on Deferred Compensation	(195,583)	(191,669)
SCS Early Retirement Costs	(50,340)	(49,338)
Executive Financial Planning	(48,000)	(48,000)
Increase in Employee Positions	(1,546,022)	(1,515,243)
Incentive Compensation	(2,348,255)	(2,301,505)
Stock Based Compensation allocated to Gulf from SCS	(1,554,547)	(1,523,599)
Total Reductions	(5,742,747)	(5,629,354)
Approved Salaries and Benefits	$106,695,530	$104,570,479

Pension Expense

We find that the appropriate amount of Pension Expense for the 2012 projected test year is $2,676,982 ($2,731,358 system).

Appropriate Amount of Accrual for Storm Damage

We find that the accrual shall not be increased from its present level and the appropriate amount of the annual storm damage accrual for the projected 2012 test year is $3,365,709 ($3,500,000 system). Therefore, Gulf's proposed accrual of $6,539,091 ($6,800,000 system) shall be reduced by $3,173,382 ($3,300,000 system).

Table 18

2012 Projected Test Year – Annual Storm Damage Accrual (System Amounts)						
Description	Gulf	OPC	FIPUG	FRF	FEA	Commission Approved
Requested annual accrual	$6,800,000	$600,000	$3,500,000	No more than $600,000	No more than $5,000,000	$3,500,000

Director's & Officer's Liability Insurance

Gulf witness Erickson addressed Director's & Officer's Liability Insurance (D&O) expense by asserting that D&O Liability Insurance is used primarily for the benefit of the customers, and that D&O Liability Insurance represents a normal cost of providing service. Witness Erickson went on to explain that D&O Liability Insurance is necessary for the Company to attract and retain competent and skilled directors and officers, which ensures proper management and oversight of the Company, which in turn benefits the customers.

Gulf witness Deason reiterated witness Erickson's assertion regarding D&O Liability Insurance being a reasonable and necessary cost of doing business for any publicly-held company. Witness Deason also testified that "adequate liability coverage gives directors and officers the level of comfort necessary to enable them to make forward-looking decisions that will provide operational and cost-efficiency benefits for customers." Witness Deason noted as support two recent decisions in which we have acknowledged the need for D&O Liability Insurance.[33] He concluded that any disallowances to a reasonable and necessary business expense would constitute a "backdoor approach" to reducing a company's authorized ROE.

OPC witness Schultz testified that D&O Liability Insurance primarily benefits shareholders and that it has been his experience that in most cases where a legal suit is filed, the primary litigant is the shareholder. Witness Schultz recognized that D&O Liability Insurance does provide some benefit to the customers and thus recommended that the $118,767 included in O&M expense associated with D&O Liability Insurance be split evenly between the shareholders and companies, resulting in a reduction of $59,384 ($118,767/2) to O&M expense.

The primary argument related to D&O Liability Insurance rests on who benefits from the Company's decision to acquire it, the shareholders, the customers, or both. We agree with Gulf that D&O Liability Insurance is prudent and necessary for a publicly held company to have, and

[33] See Order Nos. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System., p. 37; and Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company., p. 64.

that it ensures the Company will be able to attract and retain skilled leadership. However, we also agree with OPC's argument that Gulf's shareholders also receive a benefit from having D&O Liability Insurance. Therefore, we find that, consistent with our prior decision in the PEF case,[34] the cost of D&O Liability Insurance shall be a shared cost.

Based on the above, we find that both the shareholders and the customers receive benefits from D&O Liability Insurance and that the associated cost shall reflect this fact. As such, we find that D&O Liability Insurance expense shall be reduced by $58,133 ($59,384 system) to share the cost equally between the shareholders and the customers.

Accrual for the Injuries & Damages Reserve

We find that the appropriate amount for the injuries and damages reserve accrual of $1,566,288 jurisdictional ($1,600,000 system) is included in the 2012 projected test year.

Tree Trimming Expense

Gulf witness Moore testified regarding Gulf's requested amount for tree trimming expense for the 2012 projected test year. He stated:

> Gulf's distribution Vegetation Management activity ($4,918,000) includes expenses to clear, trim, and maintain distribution right of way. Gulf's Vegetation Management activities are related to Gulf's Commission approved Vegetation Management Plan in Order No. PSC-06-0947-PAA-EI, Docket No. 060198-EI. This Plan includes a combination of a 3-year trim cycle on all main line feeders, a 6-year cycle on laterals, and an annual cycle of inspections and corrections on main line feeders to ensure the approved cycles are achieved.

As a result of Gulf's experience with its trim cycle approved in the 2007 storm hardening plan, Gulf determined that it was necessary to shorten the lateral trim cycle from six to four years. In 2010, Gulf submitted and we approved Gulf's updated storm hardening plan for the years 2010 through 2012. This updated plan incorporated a four-year lateral and three-year main line feeder trim cycle. Gulf witness Moore stated that the difference between the 2012 test year requested amount of $4.9 million and the $4.1 million average from 2007 to 2009 is the amount necessary for Gulf to stay on the new trim cycle for laterals approved by us in Gulf's most recent storm hardening plan.

OPC witness Schultz proposed a reduction to Gulf's 2012 projected test year tree trimming expense. He recommended a reduction of $386,834 on a jurisdictional basis. Schultz argued that:

> The total approved spending beginning in 2007 would equate to $4.7 million. Since the approval of the incremental vegetation management costs, the Company

[34] See Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., pp. 98-99.

> has average $4,293,262 as shown on Exhibit HWS-1, Schedule C-2. Limiting maintenance in previous years, for whatever reason, is no justification for passing the catch up costs on to ratepayers. Therefore, the Company's sudden increase in spending when a rate case is being filed should not be the basis for the amount to be recovered from ratepayers prospectively. An adjustment is required to reflect the level of spending the Company is actually performing in its attempt to comply with the Storm Hardening Requirements approved by the Commission in Docket No. 060198-EI.

Gulf's updated storm hardening plan was approved by us on November 15, 2010.[35] In the updated plan, we approved Gulf's proposal to reduce its trim cycle for laterals from a six-year cycle to a four-year cycle. Although we approved the shorter cycle, it was left to the Company's discretion regarding how this change would be implemented.

Gulf witness Moore explained that OPC witness Schultz's calculation for tree trimming expense is flawed. During three of the four years calculated by witness Schultz, Gulf had a longer trim cycle for laterals. Witness Schultz's calculation would be correct only if we did not approve the shorter trim cycle for lateral lines in Gulf's most recent storm hardening plan in 2010. However, since we approved a shorter trim cycle, the annual expense for tree trimming would be expected to increase due to the more frequent tree trimming of vegetation on lateral lines to comply with the plan.

OPC's analysis did not account for the most recent approved storm hardening plan in Docket No. 100265-EI. Thus, pertinent information was left out of OPC's calculations. OPC witness Schultz did not account for the shorter trim cycle for lateral lines in Gulf's current vegetation management plan. The four-year average calculation performed by witness Schultz included three years of data from the period where Gulf was on the longer trim cycle. Witness Schultz's proposed adjustment, thus, understates tree trimming expense and therefore, his adjustment shall not be adopted.

We find that Gulf's proposed 2012 projected tree trimming expense is reasonable. Gulf explained that the decreased trim cycle for laterals accounts for the increased expense. In addition, Gulf's requested amount will allow the Company to achieve the new trim cycle for laterals in the allotted time frame.

For the foregoing reasons, we hereby approve Gulf's proposed tree trimming expense for the 2012 projected test year. The appropriate amount of Gulf's tree trimming expense for the 2012 projected test year is $4,918,154.

[35] See Order No. PSC-10-0688-PAA-EI, issued November 15, 2010, in Docket No. 100265-EI, In re: Review of 2010 Electric Infrastructure Storm Hardening Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Gulf Power Company.

Production Plant O&M Expense

The Company requested $110,887,515 for production plant O&M expense according to the Company's 2012 test year budget, which is approximately 19 percent higher than the 2010 expense level. In his testimony, Gulf witness Grove asserted that expense requirements have significantly changed since the prior rate case and that, "the historical average levels of Production Plant O&M expenses for the years 2006 through 2010 are not representative of Gulf's going forward level of Production Plant O&M expenses." Witness Grove continued by listing five primary factors driving the production plant O&M expense increase after 2010:

> First . . . the age of Gulf's generation fleet is increasing, and with age, greater levels of maintenance are necessary to maintain or improve generating unit performance. Second, there are a number of costs in the Production function that are simply increasing at a rate higher than the Consumer Price Index (CPI), the general measure of inflation. Third, Gulf has a generating unit (Smith Unit 3) that was relatively new in the 2006-2010 time-periods and required very little O&M expense. Fourth, Gulf has one new unit (Perdido) that was not constructed and operational until October 2010. Fifth, Gulf worked very hard during the 2009-2010 time frames to avoid asking for base rate relief . . . However, the historical level of expenses is not sustainable without affecting the reliability and efficiency of our fleet.

OPC's proposed 2012 Production Plant O&M expense was based on a calculated escalation factor, effectively levelizing the overall cost. OPC used the historical five-year average from 2006 to 2010 as a starting point and escalated the value by two years to project a 2012 Production Plant O&M expense.

OPC witness Schultz began his calculations by averaging the total Production Plant O&M expenses over the 2006-2010 time period, resulting in $85,487,069. This value was increased by a 5.5 percent escalation factor in two iterations to represent 2011 and 2012. Witness Schultz explained how he calculated and justified the escalation factor of 5.5 percent in the his testimony:

> The 5.5% increase is the actual net increase from 2008 to 2010. I regard this as more than reasonable since . . . costs over the past five years have increased as well as decreased resulting in a simple average annual increase 2.24%.

Witness Schultz finalized his calculations by making adjustments for labor costs:

> After escalating the average costs, I added the Company increase in labor, using the Company's 2012 labor of $30,828,000 and subtracting the five year average labor of $26,765,000. The average was calculated from Company Exhibit No. (RWG-1), Schedule 7 . . . The result is a recommended Production O&M expense of $99,212,245.

OPC's calculations are summarized in Table 19 below.

Table 19

OPC's Calculations	
2006-2010 Average Production O&M Expense	$85,487,069
Escalation Factor	5.5%
Projected 2011 Budget	$90,188,858
Projected 2012 Budget	$95,149,245
Labor Adjustment	+$4,063,000
Adjusted Total Production O&M Expense	$99,212,245
Total Adjustment to Gulf's Request	-$11,675,270

Witness Schultz did not provide any justification as to why the difference between 2008 and 2010 values were used to calculate the escalation factor. Additionally, the net increase percentage between the 2008 and 2010 Production Plant O&M expense is actually 5.05 percent, not 5.5 percent as indicated previously. Witness Schultz also did not provide any explanation as to why a labor adjustment was applied, or to the method in which it was applied. Furthermore, the five year average of the overall Production Plant cost of $85,487,069 already included baseline labor costs. The addition of the Company's budgeted 2012 labor amount of $30,828,000 and subtraction of the five-year average labor of $26,756,000 resulted in double-counting the labor portion of the expenses.

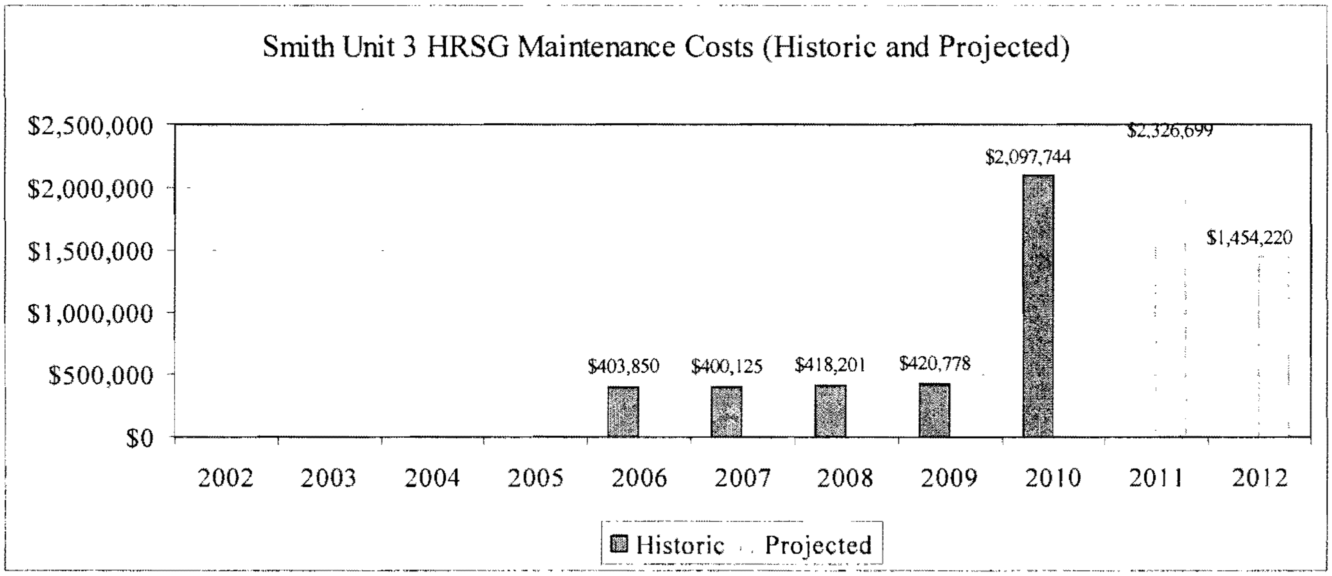
Even excluding the errors in OPC's calculations, we do not agree with OPC's method of computing a projected 2012 Production Plant O&M expense based on the averaging of historical levels. OPC's process lacks adequate justification, is inconsistent in specific values chosen, and the overall nature of projecting annual costs using a randomly selected escalation percent is unnecessarily arbitrary and is not indicative of actual O&M costs going forward.

However, an adjustment is warranted to Production Plant O&M expense because of extraordinary items of maintenance whose costs and frequency have been shown to be inconsistent on an annual basis. Although we recognize the validity of several of Gulf witness Grove's justifications, we have concerns regarding the significant increase of the Production Plant O&M expense after 2010. Specifically, with respect to an adjustment to the Production Plant O&M costs related to the Smith Unit 3 Heat Recovery Steam Generation (HRSG) unit and other non-recurring costs. Our approach incorporates these non-recurring items of maintenance to calculate a Production Plant O&M expense for the test year that better represents Gulf's expected annual expenditures on a going-forward basis.

Smith 3 HRSG Unit

Gulf explained that the increase in O&M costs of the Smith 3 Unit in further detail. Gulf stated that, "the major item driving up costs is maintenance related to the Heat Recovery Steam Generator and structures." These costs are summarized on an annual basis in Table 20 below.

Table 20



The above-referenced chart illustrates a significant increase in costs beginning in 2010 and a 2012 test year expense of $1,454,220, whereas the costs prior to 2010 were consistently under $500,000. According to Gulf's filings in this proceeding the significant increase is a result of replacing and maintaining the HRSG's valves and piping as well as the HRSG structure and lagging. No further explanation was given by witness Grove as to the specific procedures, frequency, and importance of these generic items of maintenance. Therefore, we are concerned that these procedures, although necessary for the Smith Unit 3 HRSG, may not be annually recurring items of maintenance and may consequently not be acceptable as an annually recurring O&M expense.

We addressed the Smith Unit 3 HRSG cost concerns by averaging the historical and budgeted six-year costs of the HRSG from 2006 to 2011. Data points prior to 2006 were omitted from the calculation because no costs for the Smith Unit 3 HRSG were recorded for these years of operation. The average cost was calculated to be $1,011,233, which is a $442,987 reduction from Gulf's test year budget of $1,454,220. We find this method provides protection from over-budgeting HRSG items of maintenance that have not been justified as necessary or to recur annually, while still providing an expense amount that considers the rise in costs related to the maintenance and operation of the HRSG unit.

Plant Daniel Unit 1 Nose Arch Repair

According to witness Grove, Gulf has scheduled plant outages in 2012 for Plant Crist Unit 6, Plant Crist Unit 7, Plant Scholz Unit 1, Plant Smith Unit 2, Plant Daniel Unit 1, and Plant Daniel Unit 2. Witness Grove explained why items not included in the prior test year resulted in benchmark variances, of which the nose arch repair of the boiler of Plant Daniel Unit 1 was identified as one of these items with cost of repairs of approximately $3.2 million. In response to staff discovery, Gulf specified, "the existing nose arch has been in service for 34 years, and we expect a similar life after these repairs are complete." Witness Grove confirmed that the extent of the repairs on the nose arch is a "singular event" and that "[Gulf doesn't] expect another three million dollar repair . . ." Witness Grove does contend that although these costs may not occur at Plant Daniel Unit 1 to such an extent, other outage items of the same one-time frequency may occur at other generation plants in future years. However, witness Grove did not detail or affirm these costs or demonstrate they will occur with any certainty. No substantial evidence supports witness Grove's claims, and should there be any year such substantial repairs not occur, ratepayers will be overpaying by approximately $3.2 million.

In order to account for our concerns regarding over-budgeting for the boiler nose arch repair of Plant Daniel Unit 1, we averaged the five-year budgeted outage expense for Plant Daniel Unit 1 from 2011 to 2015. This is illustrated in Table 21 below.

Table 21

Plant Daniel Unit 1 Budgeted Outage Expenses	
2011	$3,511,000
2012	$6,147,000
2013	$6,274,000
2014	$3,522,000
2015	$3,319,000
Average	$4,549,200

We used the budgeted outage expenses rather than historical, because historical outage costs have significantly fluctuated on an annual basis. Due to this degree of volatility, these amounts would be a poor representation of expected costs going forward. The average outage expense from 2011 through 2015 was calculated to be $4,549,200. Using this amount in place of the budgeted 2012 outage expense of $6,147,000 results in a $1,597,800 reduction. We find that this amount levelizes the costs of any one-incident items, such as the nose arch, in order to protect ratepayers from over budgeted maintenance, while providing adequate cost recovery for the Company and is a closer representation of the outage expenses of Plant Daniel Unit 1 going forward.

Overall Adjustment

As a result of our adjustments related to the HRSG unit and Plant Daniel Unit 1 items of maintenance, the adjustment from Gulf's budgeted 2012 Production Plant O&M expense of $107,243,499 ($110,888,515 system) is a reduction of $1,973,704 ($2,040,787 system) or a total of $105,269,794 ($108,847,728 system). These adjustments are summarized in Table 22 below.

Table 22

Commission Approved Adjustments

	System	Jurisdictional
Gulf's Proposed 2012 Budget for Production Plant O&M	$110,888,515	$107,243,499
HRSG Item Adjustment	($442,987)	($428,425)
Plant Daniel Unit 1 Outage Adjustment	($1,597,800)	($1,545,279)
Adjusted 2012 Budget for Production Plant O&M	$108,847,728	$105,269,794

Based on our approved adjustments, we find that the appropriate amount of Production Plant O&M expense is $105,269,794 ($108,847,728 system). This amount accounts for adjustments of the Plant Daniel Unit 1 boiler nose arch repair by levelizing its cost over the average of historical and budgeted outage expenses. It also accounts for adjusting the Smith 3 HRSG Unit costs to a historical five-year average. We find that levelizing the costs of these extensive, non-recurring items protects the ratepayers from an over-budgeted maintenance expense, while still providing sufficient funds for the Company to recover a fair amount representing expected annual costs on a going-forward basis.

Transmission O&M Expense

We find that the appropriate amount of Gulf's transmission O&M expense is $11,226,000 ($11,609,000 system).

Distribution O&M Expense

Based on our previously approved adjustments, the appropriate amount of distribution O&M expense for the 2012 projected test year is $41,538,000 ($41,596,000 system).

Rate Case Expense

Gulf witness Erickson testified that the Company proposed a total estimated rate case expense of $2,800,000, to be amortized over a four-year period beginning in 2012. The details of the Company's requested $2,800,000 rate case expense are shown on MFR Schedule C-10.

The Company stated that during the course of this rate case, it had already exceeded the amount of rate case expense that was initially requested due to the "incredible volume of discovery" and "the number of issues we would need to defend." Gulf also provided an updated schedule which reflected the actual rate case expense incurred through October 31, 2011 and a revised estimate to complete this case totaling $3,750,215. The revised estimate included reductions to Meals and Travel estimates to reflect five days of hearing instead of ten. Gulf stated that, although it has already exceeded the $2,800,000 requested rate case expense shown on MFR Schedule C-10, it is only seeking the original amount of $2,800,000.

OPC witness Ramas stated that the Company's estimates for Meals and Travel as well as many of the items included in Other Expenses are "excessive and/or unsupported." Witness Ramas stated that the Company's requested amount assumed 60 people attending the hearing for 10 days, which is excessive and unreasonable. OPC stated that a more appropriate estimate for Meals and Travel should be based on 34 people attending 5 days of hearings. Witness Ramas has also identified several items listed as Other Expenses in the Company's requested amount that OPC believes are unsupported. OPC argued that $222,000 associated with a cost of service study performed by SCS is excessive because it is in addition to amounts charged by outside consultants in this case. OPC argued that charges from SCS for IT, Human Resources, and Accounting services are unsupported and that "there has been no showing that additional support from SCS specific to the rate case in these areas are needed" and recommended removing an additional $99,000.[36] Witness Ramas has also removed $59,000 of Other Expenses, related to overtime labor, arguing that these costs are already reflected in the test year and are not incremental to costs already considered in rates.

In total, witness Ramas has proposed that Gulf's requested rate case expense amount of $2,800,000 be reduced by $482,273 ($102,273 for Meals and Travel and $380,000 for Other Expenses). OPC recommended adjustments to rate case expense would decrease the annual amortization amount by $120,586.

As discussed above, MFR Schedule C-10 shows a total requested rate case expense of $2,800,000, to be amortized over a four-year period which yields an annual amortization expense of $700,000. The treatment of the unamortized rate case expense, as it pertains to working capital, is addressed above.

Gulf submitted updated support for its rate case expense that included actual costs incurred through October 31, 2011, and a revised estimate to complete this rate case. In its revised estimate to complete this rate case, Gulf reflected increases to both Outside Consultants and Outside Legal Services and reductions to both Meals and Travel and Other Expenses as a result of a five day hearing and a current estimate of those expected to attend the hearing. Witness Erickson went on to state that "some categories of expense may be over and some may be under the original estimate, but in total, Gulf will incur incremental expense directly related to this rate case in excess of $2.8 million." We have reviewed the Company's requested amounts for Outside Consultants and Outside Legal Services and believe that given the scope and scale of

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[36] $20,000 for IT/Computers and $79,000 for Other Areas – HR, Accounting, etc.

discovery that has been propounded by our staff and the Intervenors, the amounts Outside Consultants and Outside Legal Services submitted by Gulf are reasonable and prudently incurred.

In its revised estimates, Gulf reduced its estimated total expense for Meals and Travel by $45,702 ($175,000-$129,298) to reflect five days of hearings and current estimates of people attending. OPC witness Ramas recommended reducing the Company's estimated number of hearing days from ten to five to reflect the five days scheduled for hearing in this case. Witness Ramas also recommended reducing the number of people attending the hearing, based on allowing one support staff person for each of the 17 Company witnesses in this proceeding, or 34 people. Witness Ramas went on to state that although certain people will be required to stay for the entire duration of the hearing, it is unlikely that all of the Company's witnesses will need to attend all five days of the hearing. Based on witness Ramas' recommended adjustments to the number of hearing days and people attending the hearing and corresponding adjustments to rental vehicles, OPC's total recommended reduction to Meals and Travel expense is $102,273. We are persuaded by OPC's arguments that both Gulf's initial and revised estimates are overstated, and that the methodology used by OPC witness Ramas in calculating a prudent and reasonable amount of expense for Meals and Travel is appropriate and reflects a more accurate estimate of costs incurred.

Regarding the $222,000 related to a cost of service study performed by SCS in preparation of this case, Gulf witness Erickson stated that there is no duplication of costs being requested and that Gulf had SCS perform the study because it was less expensive than having witness O'Sheasy's firm perform the study, disputing OPC witness Ramas' assertion that the costs associated with this study are not already reflected in the amount to be charged to Gulf by SCS in the projected test year. Witness Erickson also addressed OPC witness Ramas' proposed adjustments related to overtime costs and additional IT, human resources, and accounting services provided by SCS, citing the incremental costs incurred in association with responding to discovery and the technical support needed during the final hearing. Although we find that adjustments to the Company's requested level of Meals and Travel as well as Other Expenses, are warranted, we note that Gulf is not seeking recovery of rate case expense above the originally requested amount of $2,800,000 despite the fact that expenses for Outside Consultants and Outside Legal Services are estimated to exceed the originally requested amount.

Table 23

Rate Case Expense					
	Original Filing MFR C-10	Gulf Updates	Gulf Updated Filing	Commission Adjustments	Commission Adjusted
Outside Consultants	$725,000	$184,078	$909,078	0	$909,078
Outside Legal Services	$1,475,000	$842,988	$2,317,988	0	$2,317,988
Meals and Travel	$175,000	($45,702)	$129,298	($46,489)	$82,809
Other Expenses	$425,000	($31,149)	$393,851	0	$393,851
Total Expense	$2,800,000	$950,215	$3,750,215	($46,489)	$3,703,726

Based on an analysis of the updated amount of rate case expense, we find that the Company will incur rate case expenses in excess of the $2,800,000 that is being sought for inclusion in this proceeding. Therefore, we find that rate case expense shall be set at $2,800,000 with a four-year amortization period. The annual amortization amount shall be $700,000 ($2,800,000/4).

Uncollectible Expense

In the Company's MFR Schedule C-11, Gulf calculated a projected 2012 test year bad debt factor of 0.3321 percent, and included the bad debt factors for the historical years of 2007 through 2010. Bad debt factors for Gulf's historical years and the 2012 test year were determined by dividing the retail net write-offs listed in column 3 of MFR Schedule C-11 by the adjusted gross revenues listed in column 6 of that schedule. We further note that the information Gulf used to calculate the projected 2012 bad debt factor was based on projected figures, not historical data.

OPC recommended that a 4-year average bad debt factor be used to normalize the level of bad debt on a going forward basis. We agree with OPC that a 4-year average bad debt factor based on net write-offs and gross revenue is reasonable to determine the appropriate level of bad debt for the 2012 test year. We note that OPC used the information provided in Gulf's MFR Schedule C-11 for the historical years of 2007 through 2010 to calculate its recommended 4-year average 2012 bad debt factor of .3056 percent.

Although we agree that the 2012 bad debt factor shall be determined based on a 4-year average of the historical years of 2007 through 2010 as proposed by OPC, instead of a single year forecast as proposed by Gulf, find that the bad debt factor shall be calculated using the net write-offs listed in column three and the adjusted gross revenue listed in column 6 of MFR Schedule C-11. It appears that the bad debt factor calculated by OPC was determined by dividing the sum of the bad debt factors listed in column 7 of Schedule C-11 for the historical years by 4, which resulted in an inappropriate projected bad debt factor of 0.3056 percent, a projected net write-off of $3,997,000, and a resultant adjustment of $346,000.

We calculated a 2012 bad debt factor of 0.3061 percent. The factor was determined by using the actual net write-offs and adjusted gross revenue for the years 2007 through 2010, which results in a net write-off of 4,003,000 and an additional adjustment of $340,000 to the Company's projected write-off of $4,343,000 that are listed in its initial filing. The table below shows the information used to calculate the 2012 bad debt factor of 0.3061.

Table 24

Calculation of 2012 Bad Debt Factor for Uncollectible Account Expense[37]					
(1) Year	(2) Retail Net Write-Offs	(3) Retail Gross Revenues From Sales of Electricity	(4) Gulf's Bad Debt Factors (2) / (3)	(5) OPC's Bad Debt Factor (2) / (3)	(6) Comm. Bad Debt Factor (2) / (3)
2007	$2,883,000	1,028,209,000	0.2804%		
2008	$3,416,000	1,080,602,000	0.3161%		
2009	$4,029,000	1,212,400,000	0.3323%		
2010	$3,806,000	1,295,892,000	0.2937%		
2007-2010 Totals	14,134,000	4,617,103,000			
2012	$4,003,000	1,307,803,000	0.3321%	0.3056%	0.3061%

The appropriate amount of uncollectible expense for the 2012 projected year is $4,003,000 ($4,003,000 system). Therefore, the Company's uncollectible expense for the 2012 projected test year shall be reduced by $340,000 ($340,000 system). The appropriate bad debt factor is 0.3061 percent rather than Gulf's proposed rate of 0.3321 percent.

O&M Expense

Based on our adjustments above, the appropriate level of O&M Expense for the 2012 projected test year is $270,518,130 ($275,951,748 system). This is a reduction of $12,212,870 ($12,522,252 system).[38]

Depreciation and Fossil Dismantlement Expense

Based on our determinations above, the appropriate amount of depreciation and fossil dismantlement expense for the 2012 projected test year is $95,253,580 ($97,250,428 system), an increase of $73,580 ($109,428 system). Our calculations are shown on the following table.

[37] Except for the 2007 - 2010 totals used to calculate our four-year average bad debt factor for the 2012 test year, all figures were taken from page 1-1 of Gulf's MFR Schedule C-11. OPC's recommended 2012 bad debt factor was taken from Gulf's responses to OPC's discovery and OPC witness Ramas' testimony.

[38] See Schedule 3.

Table 25

2012 Test Year – Depreciation & Fossil Dismantlement Expense - Jurisdictional

Description	Gulf	Commission
Depreciation & Fossil Dismantlement Expense	$95,180,000	$95,180,000
Turbine Upgrade	2,161,000	934,000
Capitalized Incentive Compensation	0	(42,049)
Transmission Capital Additions	0	0
Non-AMI Meter Amortization	(886,000)	(886,000)
Construction Work in Progress	0	102,000
ECCR Revenues and Expenses	(23,000)	(23,000)
Incentive compensation adjustments	0	(11,371)
Total Adjustments	1,252,000	73,580
Adjusted Total	$96,432,000	$95,253,580

Depreciation and Amortization Expense

Based on our determinations above, we find that the appropriate level of Depreciation and Amortization Expense for the 2012 projected test year is $95,253,580 ($97,250,428 system), as shown in Table 26.

Table 26

2012 Test Year – Depreciation and Amortization Expense – Jurisdictional

Description	Commission
Depreciation & Amortization Expense	$95,180,000
Turbine Upgrade	934,000
Capitalized Incentive Compensation	(42,049)
Non-AMI Meter Amortization	(886,000)
Construction Work in Progress	102,000
ECCR Adjustment Error	(23,000)
Incentive Compensation	(11,371)
Total Adjustments	73,580
Adjusted Accumulated Depreciation & Amortization	$95,253,580

Taxes Other Than Income Taxes

Based on our determinations above, we find that Taxes Other Than Income for the 2012 projected test year shall be decreased by $19,187 ($19,351 system) for an adjusted total of $28,743,813 ($29,445,649 system).[39]

[39] See Schedule 3.

Parent Debt Adjustment

Gulf witness Teel stated that no funds provided by Southern Company debt have been invested in the equity of Gulf. Witness Teel further explained that, since Gulf's last rate case, Gulf has received $459 million in equity investment from Southern Company and has paid $655 million in dividends to Southern Company which is $196.8 million above Southern Company's equity investment in Gulf. Witness Teel stated that, prior to the last rate case:

> . . . Southern issued long-term debt during the growth of Southern Electric International, which was ultimately spun-out of Southern in 2001 as Mirant Corporation. Second, Southern's commercial paper borrowings, both now and at the time of the last rate case, are used to support parent-level expenditures. They are not used as a source of funds for investments in the operating companies. Finally, the Commission did not find it necessary to make a parent company adjustment during Gulf's last rate case.

Witness Teel indicated that imputing the tax benefits of Southern Company's debt to Gulf is effectively assuming Gulf has more debt in its own capital structure than actually exists. Witness Teel further indicated the adjustment would decrease the return on equity by approximately 25 basis points below the level we otherwise determines to be appropriate.

Gulf witness Deason stated the parent debt adjustment causes a discrepancy between the amount of debt used to determine a regulated utility's cost of capital and the amount of debt used to determine the regulated utility's income tax expense. To further support his position, witness Deason cited, as follows, the recommendation of technical staff in Docket No. 870386-PU, in which we considered repealing Rule 25-14.004, F.A.C.:

> The parent company debt adjustment necessarily assumes the debt of the parent company funds the equity of the utility subsidiary. This is known as double leverage. We believe that the capital structure found reasonable by the Commission should determine the interest used for tax purposes. This is known as interest reconciliation. It makes no sense to use one interest amount for capital structure and another for tax purposes. In developing capital structure, the parent subsidiary relationship is reviewed. The key is the reasonableness of the utility's capital structure.
>
> All parties in proceedings before this Commission are offered the opportunity to provide expert testimony regarding the appropriate level of income tax expense, capital structure and rate of return. All appropriate adjustments may be made without invoking Rule 25-14.004. Because Rule 25-14.004 is unnecessary it should be repealed.

Finally, witness Deason addressed OPC witness Woolridge's conclusion that witness Teel's rebuttal is not persuasive because it is impossible to trace dollars. Witness Deason stated:

> The technical staff argued that ratepayers should pay the taxes associated with or

> I find his reasoning curious. While stating it is impossible to trace dollars, he ignores the reality that the presumption in the rule and his own conclusion are exactly that, a tracing of dollars from parent debt (Southern) to subsidiary equity (Gulf). I agree that these dollars from Southern to Gulf cannot be traced or proven with certainty, hence the presumption. However, if one is to rebut the presumption which is based on tracing, one has to engage in similar "tracing" to show that the dollars were not, or more likely not, to have been invested in Gulf's equity. By his dividend analysis, Mr. Teel shows it is more likely that Southern debt was not invested in Gulf's equity. Dr. Woolridge makes no such analysis to rebut Mr. Teel's assertion. He simply relies on arguments that say the presumption can never be rebutted.

OPC disagreed with Gulf's rationale for not applying the parent debt adjustment. OPC argued that:

> Dividends in excess of equity infusions between Gulf and Southern for Gulf's chosen time frame do not rebut the presumption of the rule, especially since Mr. Teel reached back only as far as Gulf's last rate case. On cross-examination Mr. Teel stated that the reason Gulf chose the period back to the last rate case to study the level of dividends exceeding equity infusions was because a PDA was not made in the last rate case and circumstances have not changed since then. Mr. Teel admitted that depending on the time frame that is chosen, the dividend-to-equity infusion analysis could look very different.

Additionally, OPC argued that in several recent cases we have found that the companies have not successfully rebutted the presumption that the parent debt adjustment should be applied. Witness Woolridge identified four proceedings (three since 2009) in which we required a parent debt adjustment be made.

Finally, OPC argued that the jurisdictional separation factor used to calculate the final dollar amount of the adjustment should be the jurisdictional separation factor listed in MFR C-4 and not the jurisdictional separation factor indicated by Gulf witness McMillan in his rebuttal testimony.

In practice, the Parent Debt Rule, Rule 25-14.004, F.A.C., imputes the tax benefit of debt issued by a utility's parent company to a regulated utility subsidiary based on the assumption that the parent company invested the proceeds of its debt in the regulated subsidiary's equity in direct proportion to the debt in the parent company's capital structure. On its face, the Parent Debt Adjustment Rule is inconsistent with our long-standing practice of determining allowable utility taxes on a stand-alone basis. Referring to the recommendation in Docket No. 870386- PU, witness Deason stated:

> The technical staff argued that ratepayers should pay the taxes associated with or receive the tax benefit of only the items that are included in the cost of service and net operating income directly attributable to them.

Additionally, witness Deason pointed out several questionable assumptions necessary to justify implementation of the rule. Witness Deason explained that even though ratepayers are not obligated to pay the interest on the parent company's debt in rates, the tax deduction associated with the parent company's debt is imputed to the benefit of ratepayers. Consequently, the amount of debt used to determine the regulated utility's capital structure is different than the amount of debt used to determine the regulated utility's interest expense. Although we reconcile the amount of interest expense allowed in rates to the amount of debt in the capital structure, a different amount of interest expense is used to determine interest expense for tax purposes.

Witness Deason further explained that the rule calls for this adjustment regardless of the appropriateness of the regulated utility's capital structure and that the rule implies the regulated utility should have issued more debt than it did. Witness Deason cited staff's recommendation in Docket No. 870386-PU which observed that all parties in proceedings before us are offered the opportunity to provide expert testimony regarding the appropriate level of income tax expense, capital structure and rate of return and that all appropriate adjustments can be made without invoking Rule 25-14.004, F.A.C. Furthermore, witness Deason indicated that the parent debt adjustment will reduce Gulf's achieved net operating income and return on equity.

As cited above, witness Teel presented a dividend and equity infusion analysis that indicated, since Gulf's last rate case, Gulf has paid dividends to Southern Company in excess of $196 million more than Southern Company has invested in Gulf's common equity. Witness Deason stated Southern Company had only short-term commercial paper outstanding at the time of Gulf's last rate case. Witness Teel stated:

> Gulf has been a net returner of capital to Southern, not a net recipient. Thus Gulf itself has effectively provided the funding for Southern's equity investment in Gulf with its own internally generated funds.

> Witness Woolridge's position regarding the parent debt adjustment and his position regarding witness Teel's dividend analysis is stated in his testimony:

> Given the Commission's recent decisions in dockets involving Tampa Electric, Peoples Gas and Progress Energy Florida, the existence of debt in Southern Company's capital structure, and the impossibility of tracing funds to specific equity issuances, a parent debt adjustment is appropriate in this case.

We agree with witness Deason that "if one is to rebut the presumption which is based on tracing, one has to engage in similar tracing to show that the dollars were not, or more likely not, to have been invested in Gulf's equity." We also agree with witness Teel that although funds are fungible, "if exact tracing were required, the presumption in the rule would effectively be irrebuttable. This cannot be what the Commission intended."

The record indicates that Southern Company did not have long-term debt outstanding to invest in Gulf's equity at the time of Gulf's last rate case. Since Gulf's last rate case, the record evidence indicates Gulf paid dividends to Southern Company of $196 million more than

Southern Company invested in the equity of Gulf. In addition, based on its mix of equity and debt, we find that Gulf has a reasonable capital structure. Although funds cannot be traced, it is more logical to assume that Southern Company returned dividend dollars to Gulf to maintain an appropriate level of equity in Gulf than to assume Southern Company issued debt to invest in Gulf's equity. As stated by the Company, "the Commission should consider the evidence presented to rebut the presumption, the reasonableness of Gulf's capital structure, and the impact of making the adjustment on Gulf's opportunity to actually achieve the return on equity that the Commission ultimately determines to be reasonable." We find that the preponderance of the evidence indicates Gulf effectively has rebutted the presumption that Southern Company invested debt dollars in Gulf's common equity in direct proportion to the percent of debt in Southern Company's parent only capital structure. Consequently, we find that no parent debt adjustment shall be made in this case.

Income Tax Expense

Our adjustments to expenses will increase/decrease the Income Tax expense based on the statutory income tax rate of 38.575 percent. The Income Tax expense for the 2012 projected test year shall be \$19,698,828 (\$22,894,889 system), an increase of \$5,418,828 (\$5,525,889 system) to the Company's filed amount of \$14,280,000 (\$17,369,000). (See Schedule 3)

Total Operating Expenses

Based on our adjustments, the appropriate level of Total Operating Expenses for the 2012 projected test year is \$414,214,351 (\$425,542,714 system), a decrease of \$6,739,649 (\$6,906,286 system). (See Schedule 3)

Net Operating Income

Based on our adjustments, the appropriate Net Operating Income for the 2012 projected test year is \$67,694,649 (\$73,768,286 system), an increase of \$6,739,649 (\$6,906,286 system). (See Schedule 3)

IX. REVENUE REQUIREMENTS

Revenue Expansion Factor and Net Operating Income Multiplier

As discussed above, we find that an uncollectible expense rate of 0.3061 percent for the 2012 projected test year is appropriate. Based on this uncollectible expense rate, we find that the appropriate revenue expansion factor and net operating income multiplier are 61.1928 percent and 1.634179, respectively for the 2012 projected test year. The appropriate elements and rates are shown below:

Table 27

Revenue Expansion Factor and Net Operating Income Multiplier Calculation

	Description	(%) As Filed	(%) Adjusted
1	Revenue Requirement	100.0000	100.0000
2	Regulatory Assessment Fee	(0.0720)	(0.0720)
3	Bad Debt Rate	(0.3321)	(0.3061)
4	Net Before Income Tax	99.5959	99.6219
5	Combined State/Federal Income Tax @ 38.575%	(38.4191)	(38.4291)
6	Revenue Expansion Factor	61.1768	61.1928
7	NOI Multiplier (100/61.1928)	1.634607	1.634179

Annual Operating Revenue Increase

We find that the appropriate annual operating revenue increase for the 2012 projected test year is $64,101,662. We further find that a $4,021,905 step increase, effective January 2013, is appropriate as discussed above. The calculations of the 2012 operating revenue increase and the 2013 step increase are shown on the attached Schedules 5 and 6.

X. COST OF SERVICE AND RATE DESIGN

Elimination of the Interruptible Standby Service (ISS) Rate Schedule

We find that Gulf's proposal to eliminate the ISS rate schedule shall not be approved. Based on agreement reached amongst the parties to this proceeding, Gulf withdrew its proposal to eliminate the ISS rate schedule.

Residential Service Variable Pricing (RSVP) Rate Schedule

We find that Gulf's proposal to modify the RSVP rate schedule to use the Energy Conservation Cost Recovery clause to achieve the price differentials among the pricing tiers appropriately complements the program's objectives and thus, shall be approved.

Maximum kW Usage Level to Qualify for the GS Rate

We find that the maximum kW usage level to qualify for the GS rate shall be increased from 20 kW to 25 kW. Approximately 12 percent of the GSD customers have billing demands from 20 kW to 24 kW. These customers generally achieve a demand of 20 to 24 kW one or two times a year, frequently during the winter months, but do not consistently achieve billing demands above 20 kW throughout the year. Under the proposed change, these smaller customers would be eligible for, and have the opportunity to choose, Rate GS, which does not include a demand charge component. Affording these smaller customers the opportunity to choose a non-demand rate should improve customer satisfaction.

Critical Peak Pricing Option

Gulf's new critical peak pricing option for customers taking service on the commercial time-of-use rates GSDT and LPT shall be approved with modifications to reflect the following:

Gulf Power agrees to add the following language to Rate Schedules GSDT and LPT in the "Determination of Critical Peak Period" provision in each of these rate schedules. The total number of critical peak periods may not exceed one per day, and may not exceed four per week. Conditions which may result in the designation of a critical peak period by the Company include, but are not limited to:

i. A temperature forecast for the Company's service area that is above 95°F or below 32°F.
ii. Real-Time-Prices that exceed certain thresholds.
iii. Projections of system peak loads that exceed certain thresholds.

Minimum kW Demand to Qualify for the Real Time Pricing (RTP) Rate Schedule

We find that the minimum kW demand to qualify for the RTP rate schedule shall be reduced from 2,000 kW to 500 kW. The 2,000 kW applicability threshold has been in place since the initial implementation of Real Time Pricing at Gulf in 1995. More than half the customers who meet the 2,000 kW threshold avail themselves of Real Time Pricing. Gulf's experience, metering and billing abilities, and the diversity of customers indicate it is time to open it up to more and smaller customers. Gulf presently has about 300 to 350 customers who would meet the 500 kW threshold.

Minimum kW demand for New Load to Qualify for the Commercial/Industrial Service Rider (CISR)

We find that the minimum kW demand for new load to qualify for the CISR shall be reduced from 1,000 kW to 500 kW. This change is to simplify the minimum size requirement by making the Qualifying Load to be 500 kW in all cases. The current size requirement treats new load and retained load differently. The simplification will make the rate easier for customers to understand and for Gulf to administer.

Cost of Service Methodology in Designing Gulf's Rates, Treatment of Distribution Costs Within the Cost of Service Study & Allocation of the Revenue Increase Amongst Customer Classes

On December 16, 2011, the parties to the above-referenced proceeding filed a Motion for Approval of Partial Settlement Agreements (Motion). The Motion memorialized the terms of the proposed disposition of certain issues that were presented and discussed at the conclusion of the evidentiary hearing in this docket. On January 10, 2012, we deliberated and approved the Motion at our Commission Conference.

We hereby accept and approve the methodology filed by Gulf in this proceeding as Attachment A to MFR Schedule E-l and in the Exhibit MTO-2 solely for use in designing rates in this case. Distribution costs are either assigned, where possible, or allocated to Rate Class. Demand-related distribution costs at Level 3 are allocated on a Coincident Peak Demand (CP) Level 3 allocator. Demand-related distribution costs at Levels 4 and 5 are allocated on, their respective level, Non-Coincident Peak Demand (NCP) allocator. An example of a Level 3 Distribution Common Demand-related Investment is Account 362 - Station Equipment, which is allocated to Rate Class on a Level 3 CP demand allocator. An example of a Level 4 and Level 5 Common Distribution Demand-related Investment is Account 365 - Overhead Conductors. This Account has both Level 4 and Level 5 Common Investment. The Level 4 Common Investment is allocated to Rate Class on a Level 4 NCP demand allocator, and the Level 5 Common is allocated to Rate Class on a Level 5 NCP demand allocator. Customer-related Distribution costs are at both Level 4 and Level 5. These customer-related costs are allocated on their respective Level average number of customers' allocator. An example of Level 5 Distribution Customer-related Investment is Account 365 - Overhead Conductors. This customer-related investment at Level 5 is allocated to Rate Class on the average number of customers at Level 5. We note that where cost must be divided into demand and customer component, the cost of service methodology filed by Gulf in this proceeding as Attachment A to MFR Schedule E-l and in the Exhibit MTO-2 may be used in this case. The increase shall be spread among the rate classes as shown in MFR E-8 of Gulf's filing.

Customer Charges

We hereby approve Gulf's proposal to rename the customer charge to "Base Charge." The appropriate base charges for 2012 are shown in Schedule 7, and the appropriate base charges for 2013 are shown in Schedule 8. The 2012 revised charges and credits shall be effective for meter readings taken on or after 30 days following the date of our vote approving the rates and charges which, under the current schedule, would mean for meter readings on or after April 11, 2012. We hereby grant our staff the authority to administratively approve the tariffs filed to implement the charges and credits presented in Schedules 7, 8, and 9.

Demand Charges

We find that the appropriate demand charges for 2012 are shown in Schedule 7, and the appropriate demand charges for 2013 are shown in Schedule 8.

Energy Charges

We find that the appropriate energy charges for 2012 are shown in Schedule 7, and the appropriate energy charges for 2013 are shown in Schedule 8.

Charges for the Outdoor Service (OS) Lighting Rate Schedules

We find that the appropriate charges for the OS rate schedule for 2012 and 2013 are shown in Schedule 9.

Gulf's Proposal to Adjust Annually Existing Lighting Fixtures Prices

Gulf requested approval to annually re-price its existing lighting fixtures or associated facilities. Gulf currently has the ability to price new lighting options to customers without filing amendments to its tariffs through the use of its currently approved Form 4. Gulf proposed reviewing the existing tariffed lighting fixtures or associated facilities on an annual basis. If, as a result of the annual review, there is a change of 10 percent or more in either direction in any of the base rate charges, Gulf will automatically re-price the existing fixtures or associated facilities. Gulf's Form 4 (Tariff Sheet No. 7.13), is a currently approved lighting template that allows Gulf to offer new lighting options to customers without filing amendments to its tariffs; but does not extend to its existing priced fixtures and or associated facilities. Gulf proposed extending Form 4 to re-price existing lighting fixtures or associated facilities.

Gulf witness Thompson stated in his direct testimony that "Lighting technology changes, vendor changes, and material costs frequently render prices of existing fixtures stale." Witness Thompson further stated that "the ability to re-price existing fixtures, up or down, as costs change would benefit lighting customers. This proposal would allow Gulf to adjust the prices of fixtures as emerging technologies or other forces drive costs down in the market, thus benefitting Gulf's lighting customers. Similarly, if costs increase the associated prices increases are implemented gradually on an annual basis."

We have several concerns with Gulf's request. First, Gulf has not shown that fixtures or associated facilities have volatile price swings that may cause rate shock to customers to warrant the re-pricing. Second, Gulf's re-pricing method could create potential revenue shortfalls in the future. Third, the approval of the proposed annual re-pricing could pose additional concerns for lighting customers such as rate uncertainty and customer dissatisfaction.

Average Change in Price

On average, based on Gulf's requested increase, the difference between the existing prices versus the proposed prices for lighting or associated facilities result in an increase of approximately 28 percent. The 28 percent average increase translates to an approximate change of 2.8 percent a year in lighting fixtures or associated facilities over the ten year period since Gulf's last rate case. This is far below the 10 percent trigger level proposed by Gulf. In addition, witness Thompson stated labor rates, man-hours, etc. would not be updated and would not drive price adjustments, thereby supporting the notion that the average change in price is not significant, nor influenced by drivers known for causing varying price changes over short periods of time.

Potential for Revenue Shortfall

Gulf's proposed method of re-pricing as described in an illustrative example provided by witness Thompson raise concerns that there is the potential to create revenue shortfall from this method. The illustrative example given by witness Thompson states:

> A fixture that costs $650 (Gulf Power's acquisition cost) is priced using Form 4. The resulting monthly price for this fixture is $12.92. In a subsequent annual review the fixture cost is $450. The use of Form 4 then results in the monthly price being $9.62 or a 25.5% reduction. The price of these fixtures, including those already in service, would then be changed and the customer would be charged $9.62 per unit each month.

In this example, the prices of the fixtures have decreased, resulting in a decreased charge for that year. However; Gulf has already booked similar lighting fixtures or associated facilities at the higher price of $650 (which would be considered as a sunk cost), Over time, reducing the rate to recover only $450 cost for both new and in-place units will create a revenue shortfall, as the $450 price will not cover the $650 booked cost. This shortfall could negatively impact Gulf's earnings. Any revenue shortfalls would eventually be made up by either Gulf's ratepayers, shareholders, or both, negating any short term benefit received by customers.

Potential Rate Uncertainty and Customer Dissatisfaction

Most lighting contracts have a minimum term of two to five years with a three month noticing period for termination. Re-pricing lighting fixtures or associated facilities annually for existing contracts could create adverse financial impacts for customers who signed a contract for a fixed pricing option. Although Gulf's example contemplates a price decrease, witness Thompson noted that prices may increase as well. The proposal does not contain any protection for existing customers if prices increase above originally contracted rates. Witness Thompson stated during cross examination that customers who did not wish to pay a higher price for existing facilities would be required to pay a termination fee to exit an existing contract early. Witness Thompson also stated that the process for noticing customers of price changes under the annual review has not yet been determined.

Once a contract with fixed prices is signed, customers have an expectation that contract rates will be stable for the contract period, based on the terms of the contract, and that they will have adequate notice before changes are made. Having rates that potentially fluctuate in either direction on a yearly basis, with no set noticing requirement, does not support customer expectations and therefore may lead to customer dissatisfaction.

Gulf, as well as other utilities, has been allowed to negotiate rates for new fixtures or technologies not specifically listed in its tariffs. Customers who agree to these contracts are aware from the beginning that prices may fluctuate. Rates for existing lighting fixtures are shown in the respective lighting tariff sheets and customers have an expectation that those rates will remain in effect for the term of the contract unless changed by us. Base rate charges have mechanisms in place that allow a utility to petition us for approval to change its rates at any time. The utility also bears the responsibility to demonstrate to us that the requested rates are fair, just, and reasonable. Furthermore, allowing Gulf to automatically re-price its existing lighting or associated facilities on an annual basis potentially conflicts with Section 366.06(1), F.S., which states:

> A public utility shall not, directly or indirectly, charge or receive any rate not on file with the Commission for the particular class or service involved, and no change shall be made in any schedule. All applications for changes in rates shall be made to the Commission in writing under rules and regulations prescribed, and the Commission shall have the authority to determine and fix fair, just, and reasonable rates that may be requested, demanded, charged, or collected by any public utility for service.

Based upon a preponderance of the evidence in the record, we find that Gulf has not demonstrated sufficient need for annual price changes, nor compelling benefits to customers, to justify a move to annual review of lighting fixture prices. We further find that annual re-pricing is not only unnecessary from a cost basis, but that any potential benefit would be short term. In addition, such an approach could have negative impacts on the customers in the long run. On the basis of the foregoing, we hereby deny Gulf's proposal to change how its existing lighting fixtures or associated facilities are priced.

Standby and Supplemental Service (SBS) Rate Schedule

We find that the appropriate SBS charges for 2012 are shown in Schedule 7, and the appropriate SBS charges for 2013 are shown in Schedule 8.

Transformer Ownership Discounts

Gulf developed its proposed transformer ownership discounts by increasing the discount for each applicable rate class by the percentage increase in its proposed demand charge for each of the affected rate classes. The proposed discounts are identified in the table below.

Table 28

Gulf's Proposed Transformer Ownership Discounts			
Rate Schedule	Contract Level	Voltage Discount ($/KW/Month)	Voltage Level
GSD/GSDT	N/A	($0.49)	Primary
LP/ LPT	N/A	($0.64)	Primary
LP/LPT	N/A	($0.81)	Transmission
PX/PXT	N/A	($0.22)	Transmission
SBS	1 – 499 KW	($0.44)	Primary
SBS	500 – 7,499 KW	($0.84)	Primary
SBS	500 – 7,499 KW	($0.98)	Transmission
SBS	7,500 KW - above	($0.13)	Transmission
Source - Gulf BR 128			

Gulf proposed this approach to setting transformer ownership discounts in order to preserve the relationship between the magnitude of the transformer ownership discounts and the associated demand charges. Gulf stated that this approach differs somewhat from the approach utilized in the last rate case. The approach used in the last rate case was to set transformer discounts based on the cost of providing transformation service. In Docket No. 010949-EI, the revenue requirement for transformation service was determined by specified rate class groupings (e.g. GSD/GSDT). Such revenue requirements were divided by the appropriate billing units at the primary and secondary distribution levels to determine the unit cost of transformation. This unit cost of transformation was the basis for the approved transformer discounts.

In this proceeding, Gulf argued that customers who own, operate, and maintain their own voltage transformation facilities need to be able to rely on consistency in the relationship between their rate(s) and the discounts available as they make decisions as to whether to provide their own voltage transformation. Gulf stated that its motivation for structuring the transformer ownership discounts in the manner proposed is to ensure that customers who have invested in their own voltage transformation facilities in reliance on Gulf's existing ownership discounts do not see those expected savings eroded as a result of base rate increases. Gulf also stated that customers who are considering investing in their own voltage transformation facilities may be discouraged from doing so if it appears that savings associated with then-existing ownership discounts will be eroded as a result of future base rate increases.

Gulf stated that the two approaches for establishing transformer discounts yield very similar results for the GSD/GSDT and LP/LPT rate classes. Gulf noted that its approach yields a higher transformer ownership discount under Rate Schedule SBS (Standby or Supplementary Service), but the Company argued that the continuity offered through Gulf's proposal provides a more reasonable price (discount) to SBS customers. Gulf described its SBS customers as large customers who own their own generation but who nevertheless need backup service from Gulf.

Gulf's transformer discounts were determined in Gulf's last rate case based on the unit cost incurred to provide transformation services for GSD/GSDT, LP/LPT, PX/PXT, and SBS rate classes.[40] In Order No. 23573, Gulf proposed adjusting the discounts by any variance of the demand and energy charges from unit costs. As discussed above, we find that the adjustment for variance from unit costs proposed by Gulf was an unnecessary complication.

Gulf's argument to allow the transformer discounts to increase in accordance with the percentage increase in demand charges would be a departure from our prior actions in establishing such discounts. In a TECO rate proceeding, we approved cost-based transformer ownership discounts for the primary and subtransmission levels, using embedded cost of transformation and calculating an annual revenue requirement for the Company's transformation equipment.[41] This basis for establishing the level of TECO's transformation ownership

[40] See Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, In re: Request for rate increase by Gulf Power, p. 98 and Order No. 23573, issued October 3, 1990, In re: Petition of Gulf Power Company's for increase in its rates and charges, p. 57.
[41] See Order No. 11307, issued November 10, 1982, in Docket No. 820007-EU, In re: Petition of Tampa Electric Company for an increase in rates and charges, p. 47.

discounts was affirmed by us in June 2008.[42] We approved FPL's transformation rider credits based on the avoided cost of distribution secondary transformers in FPL's most recent rate case.[43]

In this docket, Gulf provided discovery responses showing the costs of providing transformation services under two different cost of service methods, one based on the Minimum Distribution System cost of service methodology (MDS) and the other based on Non-Minimum Distribution System cost of service methodology (Non-MDS). The current transformer ownership discounts, the proposed transformer ownership discounts, the MDS unit cost of transformation, and the Non-MDS unit costs of transformation are shown in Table 29.

Table 29

Gulf's Transformer Discounts and Unit Costs					
A	B	C	D	E	F
Rate Schedule and Voltage Level	Contract Level	Gulf's Current Discount ($/KW/MO)	Gulf Proposed Discount ($/KW/MO)	Unit Cost per MDS ($/KW/MO)	Unit Cost per Non-MDS ($/KW/MO)
GSD/GSDT – Primary	N/A	($0.44)	($0.49)	($0.32)	($0.45)
LP/ LPT – Primary	N/A	($0.53)	($0.64)	($0.45)	($0.64)
LP/LPT – Transmission	N/A	($0.67)	($0.81)	($0.61)	($0.81)
PX/PXT - Transmission *	N/A	($0.18)	($0.22)	No data (billing units = 0)	No data (billing units = 0)
SBS – Primary	1 – 499 KW	($0.27)	($0.44)	($0.09)	($0.15)
SBS – Primary	500 – 7,499 KW	($0.41)	($0.84)	($0.09)	($0.15)
SBS – Transmission	500 – 7,499 KW	($0.48)	($0.98)	($0.11)	($0.17)
SBS – Transmission *	7,500 KW – above	($0.07)	($0.13)	No data (billing units = 0)	No data (billing units = 0)
* Gulf indicated it has no transmission customers for these specific rate classes and thus the Company presented no unit cost data for such rate classes.					

Gulf agreed that its response to the methodology previously adopted by us provided a reasonable cost basis for transformer ownership discounts. Gulf witness Thompson agreed that the cost-based method and Gulf's proposed method based on the percentage increase in demand charges were both reasonable and that either method was acceptable because they yielded results that were "pretty close."

[42] See Order No. PSC-08-0397-PAA-EI, issued June 16, 2008, in Docket No. 070733-EI, In re: Complaint No. 694187E by Cutrale Citrus Juices USA, Inc. against Tampa Electric Company for refusing to provide transformer ownership discount for electrical service provided through Minute Maid substation., p. 6.
[43] See Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 080677-EI, In re: Petition for increase in rates by Florida Power and Light Company, p. 182.

As shown in Table 29, the unit costs of voltage transformation under MDS are lower than the unit costs of voltage transformation under Non-MDS. In addition, the unit costs of transformation under MDS are lower than current transformer discounts because the current transformer discounts were approved on the basis of the Non-MDS cost of service methodology in the last rate case. Also, Table 29 shows that the transformer ownership discounts based on the MDS cost of service study are significantly below Gulf's proposed transformer ownership discounts for all rate classes for which cost data is available. These differences are based on as-filed cost information rather than the costs we approved, which may further impact the differential between Gulf's requested transformer ownership discounts and the cost of transformer ownership discounts.

Based on the foregoing we shall continue to require a cost basis for Gulf's transformer ownership discounts. Transformer ownership discounts in excess of the Company's transformation unit costs may lead to offsetting increases in Gulf's base rates so that the Company can recover its full revenue requirement. Our concern is that any discounts offered above the Company's cost of service is expected to result in cross-subsidies. We do not agree with Gulf witness Thompson that transformer ownership discounts must increase with Gulf's proposed rate increases to prevent the erosion of customers' expected savings from installing and maintaining their own transformers. Base rates recover a myriad of costs, comprised mostly of costs other than transformation service. Gulf's rate relationship argument is not sufficient to justify deviating from our practice of cost based discounts.

We hereby set Gulf's transformer ownership discounts equal to the Company's Minimum Distribution System unit cost for transformation service for the GSD/GSDT, LP/LPT, SBS primary (100-499 KW and 500-7,499 KW), and SBS transmission (500-7,499 KW) rate classes. Transformer ownership discounts have historically been based on avoided cost of providing transformation service rather than, as proposed by Gulf, relative changes in demand charges. The calculation of the transformer ownership discounts shall be based on Gulf's MDS cost of service methodology in order to be consistent with our January 10, 2012, approval of the Motion submitted by Gulf on behalf of itself and other signatories. The final transformer ownership discounts for 2012 are shown in Schedule 7, and for 2013 are shown in Schedule 8.

For Gulf's PX/PXT and SBS "Transmission - 7500 KW and above" rate classes, we hereby set the transformer ownership discounts equal to Gulf's current transformer ownership discounts due to the lack of updated available unit cost data. The current transformer ownership discounts are -$0.18/kw/mo for the PX/PXT classes and -$0.07/kw/mo for the SBS "Transmission - 7500 KW and above" rate class.

<u>Minimum Monthly Bill Demand Charges Under the PX and PXT Rate Schedules</u>

We find that the appropriate minimum monthly bill demand charges under the PX and PXT rate schedules for 2012 are shown on Schedule 7, and for 2013 are shown in Schedule 8. These minimum bill provisions have been developed using our approved method for determining them.

XI. OTHER ISSUES

Interim Rate Increase Refund

By Order No. PSC-11-0382-PCO-EI, issued September 12, 2011, we authorized the collection of interim rates, subject to refund, pursuant to Section 366.071, F.S. The approved interim revenue increase was $38,549,000, or 8.882 percent, based on a test year ended March 31, 2011. The overall rate of return (ROR) used to calculate the interim rate increase was 6.45 percent using a 10.75 percent ROE.

Section 366.071(4), F.S., provides that the amount of any interim rate increase refund should be calculated based on the actual earnings of the Company during the time that interim rates were in effect. In this proceeding, the interim rate collection period is from September 2011 through March 2012. The test period for establishment of the interim increase was the 12-month period ended March 31, 2011. Gulf's approved interim rates did not include any provisions for pro forma or projected operating expenses or plant. The interim increase was designed to allow recovery of actual interest costs, and the lower limit of the last authorized range for return on equity.

Because the interim rate collection period continues through March 2012, we have used the actual 12-month period ended November 30, 2011, as a proxy for determining whether any refund is warranted. Per Gulf's November 2011 Earnings Surveillance Report (ESR), Gulf achieved a 4.55 percent ROR which resulted in an earned ROE of 5.80 percent. We have made a revenue adjustment of $12,850,000 [$38,549,000 x (4/12)] to this period to recognize the remaining collection period months of December 2011 through March 2012. We also reviewed the recommended adjustments for the full case to identify any that might impact the interim collection period. We identified the North Escambia County plant site and incentive compensation as adjustments that shall be included in the interim rate refund calculation. After making these adjustments, the adjusted ROR is 5.27 percent resulting in an adjusted ROE of 7.67 percent. We have approved an ROR of 6.39 percent and an ROE midpoint of 10.25 percent. Based on comparing the interim rate collection period ROR (5.27 percent) and ROE (7.67 percent) with the approved ROR (6.39 percent) and ROE (10.25 percent), we find that no interim rate increase refund is required. Further, upon expiration of the period for appeal, the corporate undertaking shall be released.

Table 30

Interim Rate Increase Refund Calculation				
	Net Operating	Rate Base	Achieved ROR	Achieved ROE
November 2011 ESR as Filed	$72,481,202	$1,591,779,161	4.55%	5.80%
Commission Adjustments:				
Remaining Interim Rate Increase (December 2011 – March 2012) (Net of Tax)	$7,864,000	0	-----	-----
Incentive Compensation (Net of Tax)	$2,367,008	($524,283)	-----	-----
North Escambia County Plant Site	0	($22,660,000)	-----	-----
Commission Adjusted Total	$82,712,210	$1,568,594,878	5.27%	7.67%
Commission Approved	-----	-----	6.39%	10.25%

As shown in Table 30, we have calculated that Gulf's achieved ROR and ROE for the interim rate collection period will be less than the approved ROR and ROE for the full case. Therefore, we find that no interim rate increase refund is required. Further, upon expiration of the period for appeal, the corporate undertaking shall be released.

Required Filings

We find that Gulf shall file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of our findings in this case.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Gulf Power Company's Petition for Rate Increase is granted in part and denied in part as set forth herein. It is further

ORDERED that each of the findings made in the body of this Order are hereby approved in every respect. It is further

ORDERED that all matters contained in the appendix, attachments, and schedules appended hereto are incorporated herein by reference. It is further

ORDERED that no refund of the interim increase approved by Order No. PSC-11-0382-PCO-EI, issued September 12, 2011, shall be required. It is further

ORDERED that the approved rates, charges, and credits shall become effective for meter readings made on or after April 11, 2012. It is further

ORDERED that Gulf Power Company shall file, within 90 days after the date of the Final Order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records that will be required as a result of the findings made in this case. It is further

ORDERED that upon expiration of the period for appeal this docket shall be closed.

By ORDER of the Florida Public Service Commission this 3rd day of April, 2012.

Ann Cole

ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

CMK

DISSENTS BY: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS

CHAIRMAN RONALD A. BRISÉ on reconsideration dissented with respect to the issue of the *Return on Equity*.

COMMISSIONER EDUARDO E. BALBIS dissented with respect to the issue of the *Storm Damage Reserve, Annual Accrual, and Target Level Range*.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Appendix 1

GULF POWER COMPANY
DOCKET NO. 110138-EI
APPROVED STIPULATIONS

The parties have reached and we have approved stipulations on several issues. These stipulations fall within one of two categories, as listed below. "Category 1" stipulations reflect the agreement of Gulf, staff, and at least one of the Intervenors in this docket. Intervenors who have not affirmatively agreed with a particular Category 1 stipulation but otherwise take no position on the issue are identified in the proposed stipulation. "Category 2" stipulations reflect the agreement of Gulf and staff where no other party has taken a position on the issue. "Category 3" stipulations reflect those stipulations which we approved at the January 10, 2012, Commission Conference.

CATEGORY 1 STIPULATIONS:

ISSUE 34: What is the appropriate cost rate for preferred stock for the 2012 projected test year?

Stipulation: The appropriate cost rate for preference stock for the 2012 projected test year is 6.39%.

ISSUE 35: What is the appropriate cost rate for short-term debt for the 2012 projected test year?

Stipulation: The appropriate cost rate for short-term debt for the 2012 projected test year is 0.13%.

ISSUE 36: What is the appropriate cost rate for long-term debt for the 2012 projected test year?

Stipulation: The appropriate cost rate for long-term debt for the 2012 projected test year is 5.26%.

ISSUE 53: Should the costs related to Work Order 466909, associated with a system-wide asset management system, be removed from operating expenses?

Stipulation: The costs associated with a system-wide asset management system related to work order 466909 should have been capitalized, rather than expensed, resulting in a reduction to test year jurisdictional O&M of $343,847 ($344,204 system).

ISSUE 58: Should the costs related to Work Order 49SWCS, related to a customer summit that is only held every other year, be removed from operating expenses?

Stipulation: The costs related to Work Order 49SWCS for a biannual customer summit should be amortized over two years. This results in a reduction to test year jurisdictional O&M of $19,450 ($20,130 system).

ISSUE 68: Should Executive Financial Planning Expenses be included in operating expenses?

Stipulation: Executive Financial Planning Expenses should not be included in operating expenses. In the course of responding to discovery, Gulf identified $48,000 ($48,000 system) of executive financial planning expenses that Gulf agrees need to be removed from operating expenses and consequently reflected in the adjustments to NOI.

ISSUE 100: Should Gulf's proposal to eliminate the Interruptible Standby Service (ISS) rate schedule be approved?

Stipulation: Gulf's proposal to eliminate the Interruptible Standby Service (ISS) rate schedule not be approved. Based on agreement reached with the intervenors, Gulf withdraws its proposal.

ISSUE 103: Should Gulf's new critical peak pricing option for customers taking service on the commercial time-of-use rates GSDT and LPT be approved?

Stipulation: Gulf's new critical peak pricing option for customers taking service on the commercial time-of-use rates GSDT and LPT should be approved with modifications to reflect the following:

Gulf Power agrees to add the following language to Rate Schedules GSDT and LPT in the "Determination of Critical Peak Period" provision in each of these rate schedules.
The total number of critical peak periods may not exceed one per day, and may not exceed four per week. Conditions which may result in the designation of a critical peak period by the Company include, but are not limited to:

i. A temperature forecast for the Company's service area that is above 95°F or below 32°F.
ii. Real-Time-Prices that exceed certain thresholds.
iii. Projections of system peak loads that exceed certain thresholds.

schedule be reduced from 2,000 kW to 500 kW?

ISSUE 104: Should the minimum kW demand to qualify for the Real Time Pricing (RTP) rate schedule be reduced from 2,000 kW to 500 kW?

Stipulation: The minimum kW demand to qualify for the Real Time Pricing (RTP) rate schedule should be reduced from 2,000 kW to 500 kW. The 2,000 kW applicability threshold has been in place since the initial implementation of Real Time Pricing at Gulf in 1995. More than half the customers who meet the 2,000 kW threshold avail themselves of Real Time Pricing. Gulf's experience, metering and billing abilities, and the diversity of customers indicate it is time to open it up to more and smaller customers. Gulf presently has about 300 to 350 customers who would meet the 500 kW threshold. (OPC and FEA do not affirmatively stipulate this issue but take no position on the issue.)

ISSUE 105: Should the minimum kW demand for new load to qualify for the Commercial/Industrial Service Rider (CISR) be reduced form 1,000 kW to 500 kW?

Stipulation: The minimum kW demand for new load to qualify for the Commercial/Industrial Service Rider (CISR) should be reduced from 1,000 kW to 500 kW. This change is to simplify the minimum size requirement by making the Qualifying Load to be 500 kW in all cases. The current size requirement treats new load and retained load differently. The simplification will make the rate easier for customers to understand and for Gulf to administer. (OPC and FEA do not affirmatively stipulate this issue but take no position on the issue.)

ISSUE 118: Should Gulf be required to file, within 60 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?

Stipulation: Gulf shall file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this case.

CATEGORY 2 STIPULATIONS:

ISSUE 2: Is Gulf's projected test period of the 12 months ending December 31, 2012 appropriate?

Stipulation: Gulf's projected test period of the 12 months ending December 31, 2012 is appropriate.

ISSUE 3: Are Gulf's forecasts of Customers, KWH, and KW by Rate Class and Revenue Class, for the 2012 projected test year appropriate?

Stipulation: Yes. Gulf's forecasts of Customer, KWH, and KW by Rate Class and Revenue Class, for the 2012 projected test year are appropriate. Gulf's econometric models and assumptions relied upon are reasonable and consistent with industry practice for developing its forecasts.

ISSUE 4: Are Gulf's estimated revenues from sales of electricity by rate class at present rates for the projected 2012 test year appropriate?

Stipulation: Gulf's estimated revenues from sales of electricity by rate class at present rates for the projected 2012 test year are appropriate.

ISSUE 5: What are the appropriate inflation, customer growth, and other trend factors for use in forecasting the test year budget?

Stipulation: The appropriate inflation, customer growth and other trend factors for use in forecasting the test year budget are as follows:

a. Inflation:
   2011 – 2.1%
   2012 – 2.8%
b. Forecasted Composite Wage and Salary Increase Guidelines:
   a. Exempt – 2.5%
   b. Non-exempt – 2.5%
   c. Covered – 2.25%
c. Customer Growth (Retail):
   2012 1.2%

ISSUE 6: Is Gulf's proposed separation of costs and revenues between the wholesale and retail jurisdictions appropriate?

Stipulation: Gulf's proposed separation of costs and revenues between the wholesale and retail jurisdictions is appropriate. Wholesale allocations are predominantly based upon the 12 MCP methodology with some revenues and expenses allocated upon the energy allocator. These methods are based upon cost causation and are consistent with the methodology used in Gulf's prior rate case and approved by this Commission.

ISSUE 7: Is the quality and reliability of electric service provided by Gulf adequate?

Stipulation: The quality and reliability of electric service provided by Gulf is adequate.

Appendix 1

ISSUE 15: What amount of Distribution Plant in Service should be included in rate base?

Stipulation: Gulf's requested level of Distribution Plant in Service, $1,029,829,000 ($1,034,325,000 system) should be reduced by $803,000 ($803,000 system) to reflect an error identified by the Company in the course of responding to discovery. The corrected amount of Distribution Plant in Service, $1,029,026,000 ($1,033,522,000 system) is appropriate to be included in rate base.

ISSUE 19: What are the appropriate depreciation parameters and resulting depreciation rate for AMI Meters (Account 370)?

Stipulation: The appropriate depreciation parameter for Gulf's AMI meter depreciation is a 15-year life with 0 percent net salvage. The resulting rate is 6.7%.

ISSUE 20: Should a capital recovery schedule be established for non-AMI meters (Account 370)? If yes, what is the appropriate capital recovery schedule?

Stipulation: An eight-year capital recovery schedule should be established for non-AMI meters (Account 370), modifying the four-year recovery period for the analog meters being retired establish when the Commission approved Gulf's most recent depreciation study in Order No. PSC-10-0458-PSS-EI. Changing the amortization period from 4 to 8 years would result in decreasing the depreciation expense adjustment to NOI by one-half or $886,000 jurisdictional ($886,000 system). The rate base adjustment related to accumulated depreciation would be decreased by $443,000 jurisdictional ($443,000 system). The unrecovered balance to be recovered is $7,088,000.

ISSUE 26: Should any adjustments be made to Gulf's fuel inventories?

Stipulation: Gulf's requested fuel inventory $83,871,000 ($86,804,000 system) should be reduced by $338,174 ($350,000 system) to reflect the necessary adjustment for Scherer In-transit fuel. In addition, consistent with Gulf's response to staff interrogatory 216, the fuel inventory should be reduced by $443,491 ($459,000 system) to reflect the test year gas storage inventory amount based on updated gas prices for 2012. The result of these two adjustments is a total test year fuel inventory amount of $83,089,332 ($85,995,000 system).

ISSUE 43: Has Gulf made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel Adjustment Clause?

Stipulation: Gulf has made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel Adjustment Clause.

ISSUE 44: Has Gulf made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause?

Stipulation: As adjusted, Gulf has made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause. As shown on Mr. McMillan's direct testimony Exhibit RJM-1, Schedule 6, Gulf's ECCR depreciation and property tax adjustments were $352,000 and $146,000, respectively. The ECCR depreciation expense adjustment should be increased to $375,000 and the ECCR property tax expense should be increased to $156,000.

ISSUE 45: Has Gulf made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause?

Stipulation: Gulf has made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause.

ISSUE 46: Has Gulf made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause?

Stipulation: Gulf has made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause. Consistent with the Stipulation entered into by all parties and approved by the Commission on November 1, 2011, the Crist Units 6 and 7 turbine upgrade investments and expenses were removed from the Environmental Cost Recovery Clause and are now being included for recovery in base rates in this proceeding.

ISSUE 65: What is the appropriate amount of advertising expenses for the 2012 projected test year?

Stipulation: The appropriate amount of advertising expenses for the 2012 projected test year is $1,132,000 ($1,132,000 system).

ISSUE 73: What is the appropriate amount of Other Post Employment Benefits Expense for the 2012 projected test year?

Stipulation: The appropriate amount of Other Post Employment Benefits Expense is $3,759,786 ($3,840,710 system).

ISSUE 75: What is the appropriate amount of Pension Expense for the 2012 projected test year?

Stipulation: The appropriate amount of Pension Expense for the 2012 projected test year is \$2,676,982 (\$2,731,358 system).

ISSUE 78: What is the appropriate amount of accrual for the Injuries & Damages reserve for the 2012 projected test year?

Stipulation: The appropriate amount for the injuries and damages reserve accrual of \$1,566,288 jurisdictional (\$1,600,000 system) is included in the 2012 projected test year.

ISSUE 85: What is the appropriate amount of Gulf's transmission O&M expense?

Stipulation: The appropriate amount of Gulf's transmission O&M expense is \$11,226,000 (\$11,609.00 system)

ISSUE 101: Should Gulf's proposal to modify the Residential Variable Pricing (ISS) rate schedule be approved?

Stipulation: Gulf's proposal to modify the Residential Service Variable Pricing (RSVP) rate schedule to use the Energy Conservation Cost Recovery clause to achieve the price differentials among the pricing tiers appropriately complements the program's objectives and should be approved.

ISSUE 102: Should the maximum kW usage level to qualify for the GS rate be increased from 20 kW to 25 kW?

Stipulation: The maximum kW usage level to qualify for the GS rate should be increased from 20 kW to 25 kW. Approximately 12% of the GSD customers have billing demands from 20 kW to 24 kW. These customers generally achieve a demand of 20 to 24 kW one or two times a year, frequently during the winter months, but do not consistently achieve billing demands above 20 kW throughout the year. Under the proposed change, these smaller customers would be eligible for, and have the opportunity to choose, Rate GS, which does not include a demand charge component. Affording these smaller customers the opportunity to choose a non-demand rate should improve customer satisfaction.

ISSUE 116: What is the appropriate minimum monthly bill demand charges under the PX and PXT rate schedules?

Stipulation: The appropriate minimum monthly bill demand charges under the PX and PXT rate schedules are \$11.90/KW/month for PX and \$11.99/KW/month for PXT. These minimum bill provisions have been developed using the FPSC approved method for determining them. These charges are subject to revision to reflect the impact, if any, of additional adjustments identified in other issues and the final rates established for the PX and PXT rate schedules.

CATEGORY 3 STIPULATIONS:

ISSUE 106: What is the appropriate cost of service methodology to be used in designing Gulf's rates?

ISSUE 107: What is the appropriate treatment of distribution costs within the cost of service study?

ISSUE 108: If a revenue increase is granted, how should it be allocated among the customer classes?

Stipulation: The following stipulation was approved at the January 10, 2012, Commission Conference.

The enumerated cost of service and rate design Issue Nos. 106, 107, and 108 shall be resolved by the Commission's acceptance and approval of the methodology filed by Gulf in this proceeding as Attachment A to MFR Schedule E-l and in the Exhibit MTO-2 solely for use in designing rates in this case. Distribution costs are either assigned, where possible, or allocated to Rate Class. Demand-related distribution costs at Level 3 are allocated on a Coincident Peak Demand (CP) Level 3 allocator. Demand-related distribution costs at Levels 4 and 5 are allocated on, their respective level, Non-Coincident Peak Demand (NCP) allocator. An example of a Level 3 Distribution Common Demand-related Investment is Account 362 - Station Equipment, which is allocated to Rate Class on a Level 3 CP demand allocator. An example of a Level 4 and Level 5 Common Distribution Demand-related Investment is Account 365 - Overhead Conductors. This Account has both Level 4 and Level 5 Common Investment. The Level 4 Common Investment is allocated to Rate Class on a Level 4 NCP demand allocator, and the Level 5 Common is allocated to Rate Class on a Level 5 NCP demand allocator. Customer-related Distribution costs are at both Level 4 and Level 5. These customer-related costs are allocated on their respective Level average number of customers' allocator. An example of Level 5 Distribution Customer-related Investment is Account 365 - Overhead Conductors. This customer-related investment at Level 5 is allocated to Rate Class on the average number of customers at Level 5. Note: Where cost must be divided into demand and customer component, the cost of service methodology filed by Gulf in this proceeding as Attachment A to MFR Schedule E-l and in the Exhibit MTO-2 may be used in this case. The increase should be spread among the rate classes as shown in MFR E-8 of Gulf's filing.

GULF POWER COMPANY
DOCKET NO. 110138-EI
13-MONTH AVERAGE RATE BASE
DECEMBER 2012 TEST YEAR

SCHEDULE 1

Issue No.		Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Nuclear Fuel - No AFUDC (Net)	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	2,612,073,000	(1,179,823,000)	1,432,250,000	60,912,000	32,233,000	0	1,525,395,000	150,609,000	1,676,004,000
	Commission Adjustments:									
6-S	Retail/Wholesale Separation	0	0	0	0	0	0	0	0	0
8	ECRC - Capitalized Items in Rate Ba:	0	0	0	0	0	0	0	0	0
9	Plant Crist 6 & 7 Turbine Upgrades	29,396,000	(1,376,000)	28,020,000	0	0	0	28,020,000	0	28,020,000
10	Non-Utility Activities	0	0	0	0	0	0	0	0	0
12	Capitalized Incentive Compensation	(1,191,000)	42,049	(1,148,951)	0	0	0	(1,148,951)	0	(1,148,951)
14	Transmission Infrastructure Projects	0	0	0	0	0	0	0	0	0
15-S	Distribution Plant	(803,000)	0	(803,000)	0	0	0	(803,000)	0	(803,000)
16	Wireless Systems (SCS WO)	0	0	0	0	0	0	0	0	0
17	SouthernLINC (SCS WO)	0	0	0	0	0	0	0	0	0
18	Plant in Service Level	0	0	0	0	0	0	0	0	0
19-S	AMI Meter Depreciation Rate	0	0	0	0	0	0	0	0	0
20-S	Non-AMI Meter Amortization	0	443,000	443,000	0	0	0	443,000	0	443,000
21	Accumulated Depreciation Level	0	0	0	0	0	0	0	0	0
22	Construction Work in Progress	2,470,000	(55,000)	2,415,000	(2,463,000)	0	0	(48,000)	0	(48,000)
23	Caryville Plant Site	0	0	0	0	0	0	0	0	0
24	North Escambia Plant Site	0	0	0	0	(26,751,000)	0	(26,751,000)	0	(26,751,000)
25	PHFFU Level	167,847	0	167,847	0	(167,847)	0	0	0	0
26-S	Fuel Inventories	0	0	0	0	0	0	0	(781,665)	(781,665)
27	Storm Damage Reserve	0	0	0	0	0	0	0	1,586,500	1,586,500
28	Unamortized Rate Case Expense	0	0	0	0	0	0	0	(2,450,000)	(2,450,000)
44-S	ECCR Adjustment Error	(59,000)	(458,000)	(517,000)	0	0	0	(517,000)	0	(517,000)
71	Incentive Compensation	(321,795)	11,339	(310,456)	0	0	0	(310,456)	0	(310,456)
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
---	Total Commission Adjustments	29,659,052	(1,392,612)	28,266,440	(2,463,000)	(26,918,847)	0	(1,115,407)	(1,645,165)	(2,760,572)
	Commission Adjusted Rate Base	2,641,732,052	(1,181,215,612)	1,460,516,440	58,449,000	5,314,153	0	1,524,279,593	148,963,835	1,673,243,428

GULF POWER COMPANY
DOCKET NO. 110138-EI
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2012 TEST YEAR

SCHEDULE 2

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	645,222,000	38.50%	11.70%	4.50%
Long-term Debt	658,459,000	39.29%	5.48%	2.15%
Short-term Debt	17,955,000	1.07%	2.12%	0.02%
Preferred Stock	73,077,000	4.36%	6.65%	0.29%
Customer Deposits	21,264,000	1.27%	6.00%	0.08%
Deferred Income Taxes	257,098,000	15.34%	0.00%	0.00%
Tax Credits - Weighted Cost	2,929,000	0.17%	8.45%	0.01%
Total	1,676,004,000	100.00%		7.05%
Equity Ratio	46.26%			

Commission Adjusted	($) Amount	($) Specific Adjustments	($) Adjusted Total	Ratio	($) Pro Rata Adjustments	($) Staff Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	645,222,000	0	645,222,000	38.50%	(1,062,755)	644,159,245	38.50%	10.25%	3.95%
Long-term Debt	658,459,000	0	658,459,000	39.29%	(1,084,558)	657,374,442	39.29%	5.26%	2.07%
Short-term Debt	17,955,000	0	17,955,000	1.07%	(29,574)	17,925,426	1.07%	0.13%	0.00%
Preferred Stock	73,077,000	0	73,077,000	4.36%	(120,366)	72,956,634	4.36%	6.39%	0.28%
Customer Deposits	21,264,000	0	21,264,000	1.27%	(35,024)	21,228,976	1.27%	6.00%	0.08%
Deferred Income Taxes	257,098,000	0	257,098,000	15.34%	(423,470)	256,674,530	15.34%	0.00%	0.00%
Tax Credits - Weighted Cost	2,929,000	0	2,929,000	0.17%	(4,824)	2,924,176	0.17%	7.66%	0.01%
Total	1,676,004,000	0	1,676,004,000	100.00%	(2,760,572)	1,673,243,428	100.00%		6.39%
Equity Ratio	46.26%					46.26%			

Interest Synchronization	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Dollar Amount Change					
Long-term Debt	(1,084,558)	5.26%	(57,048)	38.575%	22,006
Short-term Debt	(29,574)	0.13%	(38)	38.575%	15
Customer Deposits	(35,024)	6.00%	(2,101)	38.575%	811
Tax Credits - Weighted Cost	(4,824)	7.66%	(369)	38.575%	143
					22,832
Cost Rate Change					
Long-term Debt	658,459,000	-0.22%	(1,448,610)	38.575%	558,801
Short-term Debt	17,955,000	-1.99%	(357,305)	38.575%	137,830
Tax Credits - Weighted Cost	2,929,000	-0.79%	(23,181)	38.575%	8,942
					705,574
TOTAL					728,405

GULF POWER COMPANY
DOCKET NO 110138-EI
NET OPERATING INCOME
DECEMBER 2012 TEST YEAR

SCHEDULE 3

Issue No.		Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes and ITCs	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	481,909,000	0	282,731,000	95,180,000	28,763,000	14,280,000	0	420,954,000	60,955,000
	Commission Adjustments									
3-S	Sales Forecast	0	0	0	0	0	0	0	0	0
4-S	Revenues from Sales	0	0	0	0	0	0	0	0	0
5-S	Trend Factors	0	0	0	0	0	0	0	0	0
6-S	Retail/Wholesale Separation	0	0	0	0	0	0	0	0	0
9	Plant Cnst 6 & 7 Turbine Upgrades	0	0	0	934,000	0	(360,000)	0	574,000	(574,000)
12	Capitalized Incentive Compensation	0	0	0	(42,049)	0	16,220	0	(25,829)	25,829
20-S	Non-AMI Meter Amortization	0	0	0	(886,000)	0	341,775	0	(544,226)	544,226
22	Construction Work in Progress	0	0	0	102,000	0	(39,347)	0	62,654	(62,654)
39	Non-Regulated Affiliates	0	0	0	0	0	0	0	0	0
40	Non-Regulated Co Compensation	0	0	0	0	0	0	0	0	0
41	Non-Utility Activities - Revenues	0	0	0	0	0	0	0	0	0
43-S	FAC Revenues and Expenses	0	0	0	0	0	0	0	0	0
44-S	ECCR Revenues and Expenses	0	0	0	(23,000)	(10,000)	12,730	0	(20,270)	20,270
45-S	CCRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
46-S	ECRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
47	Non-Utility Activities - Rev & Exp	0	0	0	0	0	0	0	0	0
48	Affiliated Transactions	0	0	0	0	0	0	0	0	0
49	Southern Renewable Energy	0	0	0	0	0	0	0	0	0
51	SCS Cost Allocation Factors	0	0	0	0	0	0	0	0	0
52	SouthernLINC Costs	0	0	0	0	0	0	0	0	0
53-S	Asset Management System (WO)	0	0	(343,847)	0	0	132,639	0	(211,208)	211,208
55	Work Order Costs	0	0	0	0	0	0	0	0	0
56	SEC Inquiry Costs (WO)	0	0	0	0	0	0	0	0	0
57	Benefit's Review Costs (WO)	0	0	0	0	0	0	0	0	0
58-S	Biannual Customer Summit (WO)	0	0	(19,450)	0	0	7,503	0	(11.947)	11,947
59	Work Order Costs	0	0	0	0	0	0	0	0	0
60	SCS Public Relations Costs (WO)	0	0	0	0	0	0	0	0	0
61	SCS Legal Expenses (WO)	0	0	0	0	0	0	0	0	0
64	SCS Investor Relations Costs (WO)	0	0	0	0	0	0	0	0	0
65-S	Advertising Expenses	0	0	0	0	0	0	0	0	0
66	Deferred Compensation Interest	0	0	(191,669)	0	0	73,936	0	(117,733)	117,733
67	SCS Early Retirement Costs	0	0	(49,338)	0	0	19 032	0	(30,306)	30,306
68-S	Executive Financial Planning	0	0	(48,000)	0	0	18,516	0	(29 484)	29,484
69	Salaries	0	0	0	0	0	0	0	0	0
70	Employee Position Increases	0	0	(1,515,243)	0	0	584,505	0	(930,738)	930,738
71	Incentive Compensation	0	0	(3,825,104)	(11.371)	(9.187)	1.483,464	0	(2,362,198)	2,362,198
72	Employee Benefits	0	0	0	0	0	0	0	0	0
73-S	OPEB Expense	0	0	0	0	0	0	0	0	0
74	Salaries & Benefits Levels	0	0	0	0	0	0	0	0	0
75-S	Pension Expense	0	0	0	0	0	0	0	0	0
76	Storm Damage Accrual	0	0	(3,173,382)	0	0	1,224,132	0	(1,949,250)	1,949,250
77	D&O Liability Insurance	0	0	(58,133)	0	0	22,425	0	(35,708)	35,708
78-S	Injuries & Damages Reserve Expens	0	0	0	0	0	0	0	0	0
79	Tree Trimming Expense	0	0	0	0	0	0	0	0	0
84	Production Plant O&M Expenses	0	0	(1,973,704)	0	0	761 356	0	(1,212,348)	1,212,348
85-S	Transmission Plant O&M Expenses	0	0	0	0	0	0	0	0	0
86	Distribution Plant O&M Expenses	0	0	0	0	0	0	0	0	0
88	Rate Case Expense	0	0	0	0	0	0	0	0	0
89	Uncollectible Expense	0	0	(340,000)	0	0	131.155	0	(208,845)	208,845
91	Depreciation & Dismantlement Exp	0	0	0	0	0	0	0	0	0
93	Taxes Other Than Income	0	0	0	0	0	0	0	0	0
94	Parent Debt Adjustment	0	0	0	0	0	0	0	0	0
95	Income Tax Expense	0	0	0	0	0	0	0	0	0
S	Stipulation (Issues 11, 62, 63 & 80)	0	0	(675,000)	0	0	260.381	0	(414,619)	414,619
---	Interest Synchronization	0	0	0	0	0	728,405	0	728,405	(728,405)
---	Total Commission Adjustments	0	0	(12,212,870)	73,580	(19,187)	5,418,828	0	(6,739,649)	6,739,649
	Commission Adjusted Rate Base	481,909,000	0	270,518,130	95,253,580	28,743,813	19,698,828	0	414,214,351	67,694,649

SCHEDULE 4

GULF POWER COMPANY
DOCKET NO. 110138-EI
DECEMBER 2012 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

Line No.		(%) As Filed	(%) Commission Adjusted
1	Revenue Requirement	100.0000	100.0000
2	Gross Receipts Tax	0.0000	0.0000
3	Regulatory Assessment Fee	(0.0720)	(0.0720)
4	Bad Debt Rate	(0.3321)	(0.3061)
5	Net Before Income Taxes	99.5959	99.6219
6	Income Taxes (Line 5 x 38.575%)	(38.4191)	(38.4291)
7	Revenue Expansion Factor	61.1768	61.1928
8	Net Operating Income Multiplier (100%/Line 7)	1.634607	1.634179

SCHEDULE 5

GULF POWER COMPANY
DOCKET NO. 110138-EI
DECEMBER 2012 PROJECTED TEST YEAR
OPERATING REVENUE INCREASE CALCULATION

Line No.		GULF As Filed	Crist Units 6 & 7 Turbine Upgrades Adjustment	GULF Revised	Commission Adjusted	Commission January 2013 Step Increase
1.	Rate Base	$1,676,004,000	$58,747,000	$1,734,751,000	$1,673,243,428	$30,727,000
2.	Overall Rate of Return	7.05%	7.05%	7.05%	6.39%	6.39%
3.	Required Net Operating Income (1)x(2)	118,158,000	4,142,000	122,300,000	106,920,255	1,963,455
4.	Achieved Net Operating Income	60,955,000	(816,000)	60,139,000	67,694,649	(497,661)
5.	Net Operating Income Deficiency (3)-(4)	57,203,000	4,958,000	62,161,000	39,225,606	2,461,117
6.	Net Operating Income Multiplier	1.634607	1.634607	1.634607	1.634179	1.634179
7.	Operating Revenue Increase (5)x(6)	$93,504,000	$8,104,000	$101,608,000	$64,101,662	$4,021,905
8.	Estimated 2012 ECRC Credit		($3,512,000)	($3,512,000)	$0	

SCHEDULE 6

GULF POWER COMPANY
DOCKET NO. 110138-EI
ISSUE 9 - CRIST UNITS 6 & 7 TURBINE UPGRADE PROJECTS

CALCULATION OF JANUARY 1, 2013 STEP INCREASE

Line No.		GULF Jurisdictional Total Revenue Requirement	Commission Jurisdictional Total Revenue Requirement
1	Net Plant in Service	$30,727,000	$30,727,000
2	Rate Of Return	7.05%	6.39%
3	Required Return (1)x(2)	2,167,000	1,963,455
4	Depreciation Expense	1,227,000	1,227,000
5	Income Taxes [(4) x -.38575]	(473,000)	(473,315)
6	Income Tax Effect of Interest	(268,000)	(256,024)
7	Total NOI Requirement (3)+(4)+(5)+(6)	2,653,000	2,461,117
8	NOI Multiplier	1.634607	1.634179
9	Revenue Requirement (8)x(9)	$4,336,000	$4,021,905

Interest Synchronization (Commission)

	($) Rate Base	(%) Weighted Cost	($) Interest Expense
Long-Term Debt	30,727,000	2.07%	636,049
Short-Term Debt	30,727,000	0.00%	0
Customer Deposits	30,727,000	0.08%	24,582
Tax Credits - Weighted Cost	30,727,000	0.01%	3,073
Additional Interest Expense			663,703
Income Tax Rate			38.575%
Income Tax Reduction			256,024

2012
NEW RETAIL ELECTRIC SERVICE RATES

Rate Schedule	Rate Component	New Rates
RS	Base Charge ($/Bill)	$15.00
	Energy-Demand Charge (¢/KWH)	4.265 ¢
GS	Base Charge ($/Bill)	$18.00
	Energy-Demand Charge (¢/KWH)	4.835 ¢
GSD	Base Charge ($/Bill)	$44.00
	Demand Charge ($/KW)	$5.91
	Energy Charge (¢/KWH)	1.518 ¢
	Primary Voltage Discount	($0.29)
LP	Base Charge ($/Bill)	$225.00
	Demand Charge ($/KW)	$9.93
	Energy Charge (¢/KWH)	0.744 ¢
	Primary Voltage Discount	($0.41)
	Transmision Voltage Discount	($0.56)
PX	Base Charge ($/Bill)	$646.84
	Demand Charge ($/KW)	$9.36
	Energy Charge (¢/KWH)	0.346 ¢
	Minimum Monthly Bill	
	Demand Charge ($/KW)*	$11.25
	Transmission Voltage Discount	($0.18)
RSVP	Base Charge ($/Bill)	$15.00
	Participation Charge ($/Bill)	N/A
	Low P1 (¢/KWH)	4.265 ¢
	Medium P2 (¢/KWH)	4.265 ¢
	High P3 (¢/KWH)	4.265 ¢
	Critical P4 (¢/KWH)	4.265 ¢
GSTOU	Base Charge ($/Bill)	$44.00
	Summer On-Peak (¢/KWH)	16.375 ¢
	Summer Intermediate (¢/KWH)	6.100 ¢
	Summer Off-Peak (¢/KWH)	2.525 ¢
	Winter (¢/KWH)	3.542 ¢
GSDT	Base Charge ($/Bill)	$44.00
	Maximum Demand Charge ($/KW)	$2.80
	On-Peak Demand Charge ($/KW)	$3.16
	On-Peak Energy Charge (¢/KWH)	1.518 ¢
	Off-Peak Energy Charge (¢/KWH)	1.518 ¢
	Primary Voltage Discount	($0.29)
	Critical Peak Option:	
	Max Demand ($/KW)	$2.80
	On-Peak Demand ($/KW)	$1.58
	Critical Peak ($/KW)	$4.74

LPT	Base Charge ($/Bill)	$225.00
	Maximum Demand Charge ($/KW)	$1.99
	On-Peak Demand Charge ($/KW)	$7.98
	On-Peak Energy Charge (¢/KWH)	0.744 ¢
	Off-Peak Energy Charge (¢/KWH)	0.744 ¢
	Primary Voltage Discount	($0.41)
	Transmision Voltage Discount	($0.56)
	Critical Peak Option:	
	Max Demand ($/KW)	$1.99
	On-Peak Demand ($/KW)	$3.99
	Critical Peak ($/KW)	$11.97
PXT	Base Charge ($/Bill)	$646.84
	Maximum Demand Charge ($/KW)	$0.78
	On-Peak Demand Charge ($/KW)	$8.69
	On-Peak Energy Charge (¢/KWH)	0.343 ¢
	Off-Peak Energy Charge (¢/KWH)	0.343 ¢
	Minimum Monthly Bill	
	Maximum Demand Charge ($/KW)*	$11.35
	Transmission Voltage Discount	($0.18)
OS-I/II	Energy Charge (¢/KWH)	2.293 ¢
OS-III	Energy Charge (¢/KWH)	4.321 ¢
SBS 100 to 499 KW	Base Charge ($/Bill)	$248.20
	Local Facilities Charge ($/KW)	$2.64
	Reservation Charge ($/KW)	$0.94
	Daily Demand Charge ($/KW)	$0.45
	On-Peak Demand Charge ($/KW)	$3.16
	Energy Charge (¢/KWH)	1.885 ¢
	Primary Voltage Discount	($0.07)
SBS 500 to 7,499 KW	Base Charge ($/Bill)	$248.20
	Local Facilities Charge ($/KW)	$2.33
	Reservation Charge ($/KW)	$0.94
	Daily Demand Charge ($/KW)	$0.45
	On-Peak Demand Charge ($/KW)	$7.98
	Energy Charge (¢/KWH)	1.010 ¢
	Primary Voltage Discount	($0.07)
	Transmission Voltage Discount	($0.09)
SBS Above 7,499 KW	Base Charge ($/Bill)	$591.01
	Local Facilities Charge ($/KW)	$0.80
	Reservation Charge ($/KW)	$0.97
	Daily Demand Charge ($/KW)	$0.46
	On-Peak Demand Charge ($/KW)	$8.69
	Energy Charge (¢/KWH)	0.977 ¢
	Transmission Voltage Discount	($0.07)

* Minimum monthly bill demand charges for PX/PXT were derived using the FPSC approved method as shown in Gulf's response to Staff Interrogatory 15.

2013
NEW RETAIL ELECTRIC SERVICE RATES

Rate Schedule	Rate Component	New Rates
RS	Base Charge ($/Bill)	$15.00
	Energy-Demand Charge (¢/KWH)	4.313 ¢
GS	Base Charge ($/Bill)	$18.00
	Energy-Demand Charge (¢/KWH)	4.884 ¢
GSD	Base Charge ($/Bill)	$44.00
	Demand Charge ($/KW)	$5.95
	Energy Charge (¢/KWH)	1.525 ¢
	Primary Voltage Discount	($0.29)
LP	Base Charge ($/Bill)	$225.00
	Demand Charge ($/KW)	$10.01
	Energy Charge (¢/KWH)	0.750 ¢
	Primary Voltage Discount	($0.41)
	Transmision Voltage Discount	($0.56)
PX	Base Charge ($/Bill)	$646.84
	Demand Charge ($/KW)	$9.44
	Energy Charge (¢/KWH)	0.349 ¢
	Minimum Monthly Bill	
	Demand Charge ($/KW)	$11.35
	Transmission Voltage Discount	($0.18)
RSVP	Base Charge ($/Bill)	$15.00
	Participation Charge ($/Bill)	N/A
	Low P1 (¢/KWH)	4.313 ¢
	Medium P2 (¢/KWH)	4.313 ¢
	High P3 (¢/KWH)	4.313 ¢
	Critical P4 (¢/KWH)	4.313 ¢
GSTOU	Base Charge ($/Bill)	$44.00
	Summer On-Peak (¢/KWH)	16.391 ¢
	Summer Intermediate (¢/KWH)	6.119 ¢
	Summer Off-Peak (¢/KWH)	2.545 ¢
	Winter (¢/KWH)	3.562 ¢
GSDT	Base Charge ($/Bill)	$44.00
	Maximum Demand Charge ($/KW)	$2.82
	On-Peak Demand Charge ($/KW)	$3.18
	On-Peak Energy Charge (¢/KWH)	1.525 ¢
	Off-Peak Energy Charge (¢/KWH)	1.525 ¢
	Primary Voltage Discount	($0.29)
	Critical Peak Option:	
	Max Demand ($/KW)	$2.82
	On-Peak Demand ($/KW)	$1.59
	Critical Peak ($/KW)	$4.77

LPT	Base Charge ($/Bill)	$225.00
	Maximum Demand Charge ($/KW)	$2.00
	On-Peak Demand Charge ($/KW)	$8.04
	On-Peak Energy Charge (¢/KWH)	0.750 ¢
	Off-Peak Energy Charge (¢/KWH)	0.750 ¢
	Primary Voltage Discount	($0.41)
	Transmision Voltage Discount	($0.56)
	Critical Peak Option:	
	Max Demand ($/KW)	$2.00
	On-Peak Demand ($/KW)	$4.02
	Critical Peak ($/KW)	$12.06
PXT	Base Charge ($/Bill)	$646.84
	Maximum Demand Charge ($/KW)	$0.78
	On-Peak Demand Charge ($/KW)	$8.76
	On-Peak Energy Charge (¢/KWH)	0.345 ¢
	Off-Peak Energy Charge (¢/KWH)	0.345 ¢
	Minimum Monthly Bill	
	Maximum Demand Charge ($/KW)	$11.43
	Transmission Voltage Discount	($0.18)
OS-I/II	Energy Charge (¢/KWH)	2.316 ¢
OS-III	Energy Charge (¢/KWH)	4.365 ¢
SBS 100 to 499 KW	Base Charge ($/Bill)	$248.20
	Local Facilities Charge ($/KW)	$2.66
	Reservation Charge ($/KW)	$0.95
	Daily Demand Charge ($/KW)	$0.45
	On-Peak Demand Charge ($/KW)	$3.18
	Energy Charge (¢/KWH)	1.930 ¢
	Primary Voltage Discount	($0.07)
SBS 500 to 7,499 KW	Base Charge ($/Bill)	$248.20
	Local Facilities Charge ($/KW)	$2.35
	Reservation Charge ($/KW)	$0.95
	Daily Demand Charge ($/KW)	$0.45
	On-Peak Demand Charge ($/KW)	$8.04
	Energy Charge (¢/KWH)	1.055 ¢
	Primary Voltage Discount	($0.07)
	Transmission Voltage Discount	($0.09)
SBS Above 7,499 KW	Base Charge ($/Bill)	$591.01
	Local Facilities Charge ($/KW)	$0.81
	Reservation Charge ($/KW)	$0.98
	Daily Demand Charge ($/KW)	$0.47
	On-Peak Demand Charge ($/KW)	$8.76
	Energy Charge (¢/KWH)	1.022 ¢
	Transmission Voltage Discount	($0.07)

* Minimum monthly bill demand charges for PX/PXT were derived using the FPSC approved method as shown in Gulf's response to Staff Interrogatory 15.

2012
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
HIGH PRESSURE SODIUM VAPOR (OS-I/II)								
5400 LUMEN	Open Bottom	3,108	29	90,132	$2.89	$1.55	$0.67	$5.11
8800 LUMEN	Open Bottom	603,876	41	24,758,916	$2.47	$1.41	$0.94	$4.82
8800 LUMEN	Open Bottom w/Shield	132	41	5,412	$3.39	$1.66	$0.94	$5.99
8800 LUMEN	Acorn	33,120	41	1,357,920	$12.30	$4.15	$0.94	$17.39
8800 LUMEN	Colonial	30,144	41	1,235,904	$3.31	$1.63	$0.94	$5.88
8800 LUMEN	English Coach	876	41	35,916	$13.44	$4.46	$0.94	$18.84
8800 LUMEN	Destin Single	12	41	492	$23.11	$7.17	$0.94	$31.22
5400 LUMEN	Cobrahead	6,132	29	177,828	$4.05	$1.87	$0.67	$6.59
8800 LUMEN	Cobrahead	369,624	41	15,154,584	$3.39	$1.66	$0.94	$5.99
20000 LUMEN	Cobrahead	37,872	80	3,029,760	$4.66	$2.03	$1.84	$8.53
25000 LUMEN	Cobrahead	23,184	100	2,318,400	$4.53	$2.00	$2.29	$8.82
46000 LUMEN	Cobrahead	30,384	164	4,982,976	$4.77	$2.06	$3.76	$10.59
8800 LUMEN	Cut-Off Cobrahead	7,380	41	302,580	$3.74	$1.75	$0.94	$6.43
25000 LUMEN	Cut-Off Cobrahead	3,984	100	398,400	$4.59	$2.02	$2.29	$8.90
46000 LUMEN	Cut-Off Cobrahead	984	164	161,376	$4.79	$2.06	$3.76	$10.61
25000 LUMEN	Bracket Mount CIS	632	100	63,200	$10.52	$3.67	$2.29	$16.48
25000 LUMEN	Tenon Top CIS	3,756	100	375,600	$10.53	$3.67	$2.29	$16.49
46000 LUMEN	Bracket Mount CIS	516	161	83,076	$11.18	$3.85	$3.70	$18.73
25000 LUMEN	Small ORL	444	100	44,400	$10.36	$3.62	$2.29	$16.27
46000 LUMEN	Small ORL	972	164	159,408	$10.85	$3.76	$3.76	$18.37
20000 LUMEN	Large ORL	3,432	80	274,560	$17.54	$5.62	$1.84	$25.00
46000 LUMEN	Large ORL	432	164	70,848	$19.76	$6.24	$3.76	$29.76
46000 LUMEN	Shoebox	1,284	164	210,576	$9.06	$3.26	$3.76	$16.08
16000 LUMEN	Directional	132	68	8,976	$5.09	$2.12	$1.56	$8.77
20000 LUMEN	Directional	2,904	80	232,320	$7.36	$2.79	$1.84	$11.99
46000 LUMEN	Directional	156,384	164	25,646,976	$5.46	$2.25	$3.76	$11.47
125000 LUMEN	Directional	732	379	277,428	$8.67	$3.33	$8.69	$20.69

2012
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
HIGH PRESSURE SODIUM VAPOR (OS-I/II) - PAID UP FRONT								
8800 LUMEN	Open Bottom PUF	2,412	41	98,892	N/A	$1.41	$0.94	$2.35
8800 LUMEN	Acorn PUF	9,420	41	386,220	N/A	$4.15	$0.94	$5.09
8800 LUMEN	Colonial PUF	6,120	41	250,920	N/A	$1.63	$0.94	$2.57
8800 LUMEN	English Coach PUF	396	41	16,236	N/A	$4.46	$0.94	$5.40
8800 LUMEN	Cobrahead PUF	19,968	41	818,688	N/A	$1.66	$0.94	$2.60
20000 LUMEN	Cobrahead PUF	3,096	80	247,680	N/A	$2.03	$1.84	$3.87
25000 LUMEN	Cobrahead PUF	4,704	100	470,400	N/A	$2.00	$2.29	$4.29
46000 LUMEN	Cobrahead PUF	6,192	164	1,015,488	N/A	$2.06	$3.76	$5.82
8800 LUMEN	Cut-Off Cobrahead PUF	732	41	30,012	N/A	$1.75	$0.94	$2.69
25000 LUMEN	Cut-Off Cobrahead PUF	1,872	100	187,200	N/A	$2.02	$2.29	$4.31
46000 LUMEN	Cut-Off Cobrahead PUF	396	164	64,944	N/A	$2.06	$3.76	$5.82
25000 LUMEN	Bracket Mount CIS PUF	1,704	100	170,400	N/A	$3.67	$2.29	$5.96
25000 LUMEN	Tenon Top CIS PUF	492	100	49,200	N/A	$3.67	$2.29	$5.96
25000 LUMEN	Small ORL PUF	192	100	19,200	N/A	$3.62	$2.29	$5.91
46000 LUMEN	Small ORL PUF	276	164	45,264	N/A	$3.76	$3.76	$7.52
46000 LUMEN	Shoebox PUF	384	164	62,976	N/A	$3.26	$3.76	$7.02
46000 LUMEN	Directional PUF	984	164	161,376	N/A	$2.25	$3.76	$6.01
METAL HALIDE (OS-I/II)								
12000 LUMEN	Acorn	852	72	61,344	$12.42	$5.22	$1.65	$19.29
12000 LUMEN	Colonial	1,644	72	118,368	$3.43	$2.73	$1.65	$7.81
12000 LUMEN	Destin Single	540	72	38,880	$23.23	$8.25	$1.65	$33.13
24000 LUMEN	Destin Double	60	144	8,640	$46.31	$15.43	$3.30	$65.04
32000 LUMEN	Small Flood	41,184	163	6,712,992	$5.58	$2.42	$3.73	$11.73
32000 LUMEN	Parking Lot	4,272	163	696,336	$10.31	$3.74	$3.73	$17.78
100000 LUMEN	Large Flood	27,792	378	10,505,376	$8.01	$4.79	$8.67	$21.47
100000 LUMEN	Large Parking Lot	2,592	378	979,776	$17.80	$6.64	$8.67	$33.11

2012
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
METAL HALIDE (OS-I/II) - PAID UP FRONT								
12000 LUMEN	Acorn PUF	816	72	58,752	N/A	$5.22	$1.65	$6.87
12000 LUMEN	Colonial PUF	72	72	5,184	N/A	$2.73	$1.65	$4.38
12000 LUMEN	Destin Single PUF	408	72	29,376	N/A	$8.25	$1.65	$9.90
24000 LUMEN	Destin Double PUF	60	144	8,640	N/A	$15.43	$3.30	$18.73
32000 LUMEN	Small Flood PUF	192	163	31,296	N/A	$2.42	$3.73	$6.15
32000 LUMEN	Parking Lot PUF	372	163	60,636	N/A	$3.74	$3.73	$7.47
100000 LUMEN	Large Flood PUF	228	378	86,184	N/A	$4.79	$8.67	$13.46
100000 LUMEN	Large Parking Lot PUF	144	378	54,432	N/A	$6.64	$8.67	$15.31
COMBINED HIGH PRESSURE SODIUM/METAL HALIDE (OS-I/II) - PAID UP FRONT								
20800 LUMEN	Destin Combo PUF	120	113	13,560	N/A	$15.24	$2.59	$17.83
METAL HALIDE PULSE START (OS-I/II)								
13000 LUMEN	Acorn PS	828	65	53,820	$14.09	$5.08	$1.49	$20.66
13000 LUMEN	Colonial PS	588	65	38,220	$4.40	$2.38	$1.49	$8.27
33000 LUMEN	Small Flood PS	3984	137	545,808	$6.26	$3.08	$3.14	$12.48
METAL HALIDE PULSE START (OS-I/II) - PAID UP FRONT								
13000 LUMEN	Acorn PS PUF	12	65	780	N/A	$5.08	$1.49	$6.57
33000 LUMEN	Small Flood PS PUF	192	137	26,304	N/A	$3.08	$3.14	$6.22
LED (OS-I/II)								
4440 LUMEN	LED Street Light	336	25	8,400	$12.84	$4.40	$0.57	$17.81
7200 LUMEN	E132 A3	108	45	4,860	$25.68	$7.51	$1.04	$34.23
LED (OS-I/II) - PAID UP FRONT								
5000 LUMEN	Acorn A5 PUF	240	25	6,000	N/A	$7.37	$0.57	$7.94
5000 LUMEN	Acorn A3 PUF	348	25	8,700	N/A	$7.37	$0.57	$7.94

2012
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
MERCURY VAPOR (OS-I/II)								
7000 LUMEN	Open Bottom	22,500	67	1,507,500	$2.00	$1.24	$1.54	$4.78
3200 LUMEN	Cobrahead	3,180	39	124,020	$3.71	$1.74	$0.89	$6.34
7000 LUMEN	Cobrahead	2,892	67	193,764	$3.37	$1.62	$1.54	$6.53
9400 LUMEN	Cobrahead	144	95	13,680	$4.42	$1.98	$2.18	$8.58
17000 LUMEN	Cobrahead	1,584	152	240,768	$4.83	$2.06	$3.48	$10.37
48000 LUMEN	Cobrahead	12	372	4,464	$9.71	$3.58	$8.53	$21.82
17000 LUMEN	Directional	192	163	31,296	$7.27	$2.75	$3.73	$13.75
CUSTOMER-OWNED MISC STREET/OUTDOOR LIGHTING (OS-I/II)				6,747,852	N/A	N/A	$0.02293	N/A
CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR (OS-I/II)								
8800 LUMEN	Unmetered	1,116	41	45,756	N/A	$0.63	$0.94	$1.57
46000 LUMEN	Unmetered	300	164	49,200	N/A	$0.64	$3.76	$4.40
8800 LUMEN	Metered	228	N/A	N/A	N/A	$0.63	N/A	$0.63
20000 LUMEN	Metered	408	N/A	N/A	N/A	$0.64	N/A	$0.64
25000 LUMEN	Metered	240	N/A	N/A	N/A	$0.66	N/A	$0.66
46000 LUMEN	Metered	120	N/A	N/A	N/A	$0.64	N/A	$0.64
CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - METAL HALIDE (OS I/II)								
32000 LUMEN	Unmetered	24	163	3,912	N/A	$0.78	$3.73	$4.51
32000 LUMEN	Metered	360	N/A	N/A	N/A	$0.78	N/A	$0.78
HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED/CUSTOMER MAINTAINED (OS-I/II)								
Customer-Owned	8800	384	41	15,744	N/A	N/A	$0.94	$0.94
Customer-Owned	20000	48	80	3,840	N/A	N/A	$1.84	$1.84
Customer-Owned	25000	4,236	100	423,600	N/A	N/A	$2.29	$2.29
Customer-Owned	46000	12	164	1,968	N/A	N/A	$3.76	$3.76

2012
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
ADDITIONAL FACILITIES								
13 Ft. Decorative Concrete Pole		33,720	N/A	N/A	N/A	N/A	N/A	$15.64
17 Ft. Decorative Base Aluminum Pole		132	N/A	N/A	N/A	N/A	N/A	$16.42
20 Ft. Fiberglass Pole		26,424	N/A	N/A	N/A	N/A	N/A	$5.81
30 Ft. Wood Pole		30,672	N/A	N/A	N/A	N/A	N/A	$3.76
30 Ft. Concrete Pole		62,352	N/A	N/A	N/A	N/A	N/A	$7.89
30 Ft. Fiberglass Pole w/Pedestal		684	N/A	N/A	N/A	N/A	N/A	$37.32
35 Ft. Concrete Pole		1,500	N/A	N/A	N/A	N/A	N/A	$11.49
35 Ft. Tenon Top Concrete Pole		1,668	N/A	N/A	N/A	N/A	N/A	$15.88
35 Ft. Wood Pole		63,768	N/A	N/A	N/A	N/A	N/A	$5.47
40 Ft. Wood Pole		1,128	N/A	N/A	N/A	N/A	N/A	$6.75
45 Ft. Concrete Pole (Tenon Top)		1,968	N/A	N/A	N/A	N/A	N/A	$20.83
Single Arm - Shoebox		804	N/A	N/A	N/A	N/A	N/A	$2.20
Double Arm - Shoebox		132	N/A	N/A	N/A	N/A	N/A	$2.43
Tenon Top Adapter		636	N/A	N/A	N/A	N/A	N/A	$4.06
Optonal 100 Amp Relay		72	N/A	N/A	N/A	N/A	N/A	$22.55
Miscellaneous Additional Facilities		$659,714.84	N/A	N/A	N/A	N/A	N/A	N/A

2013
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
HIGH PRESSURE SODIUM VAPOR (OS-I/II)								
5400 LUMEN	Open Bottom	3,108	29	90,132	$2.91	$1.57	$0.67	$5.15
8800 LUMEN	Open Bottom	603,876	41	24,758,916	$2.49	$1.42	$0.95	$4.86
8800 LUMEN	Open Bottom w/Shield	132	41	5,412	$3.42	$1.67	$0.95	$6.04
8800 LUMEN	Acorn	33,120	41	1,357,920	$12.43	$4.19	$0.95	$17.57
8800 LUMEN	Colonial	30,144	41	1,235,904	$3.35	$1.65	$0.95	$5.95
8800 LUMEN	English Coach	876	41	35,916	$13.57	$4.50	$0.95	$19.02
8800 LUMEN	Destin Single	12	41	492	$23.34	$7.24	$0.95	$31.53
5400 LUMEN	Cobrahead	6,132	29	177,828	$4.09	$1.89	$0.67	$6.65
8800 LUMEN	Cobrahead	369,624	41	15,154,584	$3.42	$1.67	$0.95	$6.04
20000 LUMEN	Cobrahead	37,872	80	3,029,760	$4.71	$2.05	$1.85	$8.61
25000 LUMEN	Cobrahead	23,184	100	2,318,400	$4.58	$2.02	$2.31	$8.91
46000 LUMEN	Cobrahead	30,384	164	4,982,976	$4.82	$2.08	$3.79	$10.69
8800 LUMEN	Cut-Off Cobrahead	7,380	41	302,580	$3.78	$1.77	$0.95	$6.50
25000 LUMEN	Cut-Off Cobrahead	3,984	100	398,400	$4.64	$2.04	$2.31	$8.99
46000 LUMEN	Cut-Off Cobrahead	984	164	161,376	$4.84	$2.08	$3.79	$10.71
25000 LUMEN	Bracket Mount CIS	632	100	63,200	$10.62	$3.71	$2.31	$16.64
25000 LUMEN	Tenon Top CIS	3,756	100	375,600	$10.63	$3.71	$2.31	$16.65
46000 LUMEN	Bracket Mount CIS	516	161	83,076	$11.30	$3.89	$3.73	$18.92
25000 LUMEN	Small ORL	444	100	44,400	$10.47	$3.66	$2.31	$16.44
46000 LUMEN	Small ORL	972	164	159,408	$10.96	$3.79	$3.79	$18.54
20000 LUMEN	Large ORL	3,432	80	274,560	$17.72	$5.67	$1.85	$25.24
46000 LUMEN	Large ORL	432	164	70,848	$19.96	$6.30	$3.79	$30.05
46000 LUMEN	Shoebox	1,284	164	210,576	$9.15	$3.29	$3.79	$16.23
16000 LUMEN	Directional	132	68	8,976	$5.14	$2.14	$1.58	$8.86
20000 LUMEN	Directional	2,904	80	232,320	$7.43	$2.82	$1.85	$12.10
46000 LUMEN	Directional	156,384	164	25,646,976	$5.52	$2.28	$3.79	$11.59
125000 LUMEN	Directional	732	379	277,428	$8.76	$3.36	$8.78	$20.90

2013
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
HIGH PRESSURE SODIUM VAPOR (OS-I/II) - PAID UP FRONT								
8800 LUMEN	Open Bottom PUF	2,412	41	98,892	N/A	$1.42	$0.95	$2.37
8800 LUMEN	Acorn PUF	9,420	41	386,220	N/A	$4.19	$0.95	$5.14
8800 LUMEN	Colonial PUF	6,120	41	250,920	N/A	$1.65	$0.95	$2.60
8800 LUMEN	English Coach PUF	396	41	16,236	N/A	$4.50	$0.95	$5.45
8800 LUMEN	Cobrahead PUF	19,968	41	818,688	N/A	$1.67	$0.95	$2.62
20000 LUMEN	Cobrahead PUF	3,096	80	247,680	N/A	$2.05	$1.85	$3.90
25000 LUMEN	Cobrahead PUF	4,704	100	470,400	N/A	$2.02	$2.31	$4.33
46000 LUMEN	Cobrahead PUF	6,192	164	1,015,488	N/A	$2.08	$3.79	$5.87
8800 LUMEN	Cut-Off Cobrahead PUF	732	41	30,012	N/A	$1.77	$0.95	$2.72
25000 LUMEN	Cut-Off Cobrahead PUF	1,872	100	187,200	N/A	$2.04	$2.31	$4.35
46000 LUMEN	Cut-Off Cobrahead PUF	396	164	64,944	N/A	$2.08	$3.79	$5.87
25000 LUMEN	Bracket Mount CIS PUF	1,704	100	170,400	N/A	$3.71	$2.31	$6.02
25000 LUMEN	Tenon Top CIS PUF	492	100	49,200	N/A	$3.71	$2.31	$6.02
25000 LUMEN	Small ORL PUF	192	100	19,200	N/A	$3.66	$2.31	$5.97
46000 LUMEN	Small ORL PUF	276	164	45,264	N/A	$3.79	$3.79	$7.58
46000 LUMEN	Shoebox PUF	384	164	62,976	N/A	$3.29	$3.79	$7.08
46000 LUMEN	Directional PUF	984	164	161,376	N/A	$2.28	$3.79	$6.07
METAL HALIDE (OS-I/II)								
12000 LUMEN	Acorn	852	72	61,344	$12.55	$5.28	$1.66	$19.49
12000 LUMEN	Colonial	1,644	72	118,368	$3.47	$2.76	$1.66	$7.89
12000 LUMEN	Destin Single	540	72	38,880	$23.46	$8.33	$1.66	$33.45
24000 LUMEN	Destin Double	60	144	8,640	$46.78	$15.58	$3.34	$65.70
32000 LUMEN	Small Flood	41,184	163	6,712,992	$5.64	$2.44	$3.77	$11.85
32000 LUMEN	Parking Lot	4,272	163	696,336	$10.42	$3.78	$3.77	$17.97
100000 LUMEN	Large Flood	27,792	378	10,505,376	$8.09	$4.84	$8.76	$21.69
100000 LUMEN	Large Parking Lot	2,592	378	979,776	$17.98	$6.71	$8.76	$33.45

2013
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
METAL HALIDE (OS-I/II) - PAID UP FRONT								
12000 LUMEN	Acorn PUF	816	72	58,752	N/A	$5.28	$1.66	$6.94
12000 LUMEN	Colonial PUF	72	72	5,184	N/A	$2.76	$1.66	$4.42
12000 LUMEN	Destin Single PUF	408	72	29,376	N/A	$8.33	$1.66	$9.99
24000 LUMEN	Destin Double PUF	60	144	8,640	N/A	$15.58	$3.34	$18.92
32000 LUMEN	Small Flood PUF	192	163	31,296	N/A	$2.44	$3.77	$6.21
32000 LUMEN	Parking Lot PUF	372	163	60,636	N/A	$3.78	$3.77	$7.55
100000 LUMEN	Large Flood PUF	228	378	86,184	N/A	$4.84	$8.76	$13.60
100000 LUMEN	Large Parking Lot PUF	144	378	54,432	N/A	$6.71	$8.76	$15.47
COMBINED HIGH PRESSURE SODIUM/METAL HALIDE (OS-I/II) - PAID UP FRONT								
20800 LUMEN	Destin Combo PUF	120	113	13,560	N/A	$15.39	$2.61	$18.00
METAL HALIDE PULSE START (OS-I/II)								
13000 LUMEN	Acorn PS	828	65	53,820	$14.24	$5.13	$1.51	$20.88
13000 LUMEN	Colonial PS	588	65	38,220	$4.44	$2.41	$1.51	$8.36
33000 LUMEN	Small Flood PS	3984	137	545,808	$6.32	$3.11	$3.17	$12.60
METAL HALIDE PULSE START (OS-I/II) - PAID UP FRONT								
13000 LUMEN	Acorn PS PUF	12	65	780	N/A	$5.13	$1.51	$6.64
33000 LUMEN	Small Flood PS PUF	192	137	26,304	N/A	$3.11	$3.17	$6.28
LED (OS-I/II)								
4440 LUMEN	LED Street Light	336	25	8,400	$12.97	$4.44	$0.58	$17.99
7200 LUMEN	E132 A3	108	45	4,860	$25.94	$7.59	$1.05	$34.58
LED (OS-I/II) - PAID UP FRONT								
5000 LUMEN	Acorn A5 PUF	240	25	6,000	N/A	$7.44	$0.58	$8.02
5000 LUMEN	Acorn A3 PUF	348	25	8,700	N/A	$7.44	$0.58	$8.02

2013
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
MERCURY VAPOR (OS-I/II)								
7000 LUMEN	Open Bottom	22,500	67	1,507,500	$2.02	$1.25	$1.55	$4.82
3200 LUMEN	Cobrahead	3,180	39	124,020	$3.75	$1.76	$0.90	$6.41
7000 LUMEN	Cobrahead	2,892	67	193,764	$3.41	$1.64	$1.55	$6.60
9400 LUMEN	Cobrahead	144	95	13,680	$4.47	$2.00	$2.20	$8.67
17000 LUMEN	Cobrahead	1,584	152	240,768	$4.88	$2.08	$3.52	$10.48
48000 LUMEN	Cobrahead	12	372	4,464	$9.80	$3.61	$8.61	$22.02
17000 LUMEN	Directional	192	163	31,296	$7.35	$2.78	$3.77	$13.90
CUSTOMER-OWNED MISC STREET/OUTDOOR LIGHTING (OS-I/II)				6,747,852	N/A	N/A	$0.02316	N/A
CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR (OS-I/II)								
8800 LUMEN	Unmetered	1,116	41	45,756	N/A	$0.64	$0.95	$1.59
46000 LUMEN	Unmetered	300	164	49,200	N/A	$0.65	$3.79	$4.44
8800 LUMEN	Metered	228	N/A	N/A	N/A	$0.64	N/A	$0.64
20000 LUMEN	Metered	408	N/A	N/A	N/A	$0.65	N/A	$0.65
25000 LUMEN	Metered	240	N/A	N/A	N/A	$0.66	N/A	$0.66
46000 LUMEN	Metered	120	N/A	N/A	N/A	$0.65	N/A	$0.65
CUSTOMER OWNED WITH RELAMPING SERVICE AGREEMENT - METAL HALIDE (OS I/II)								
32000 LUMEN	Unmetered	24	163	3,912	N/A	$0.78	$3.77	$4.55
32000 LUMEN	Metered	360	N/A	N/A	N/A	$0.78	N/A	$0.78
HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED/CUSTOMER MAINTAINED (OS-I/II)								
Customer-Owned	8800	384	41	15,744	N/A	N/A	$0.95	$0.95
Customer-Owned	20000	48	80	3,840	N/A	N/A	$1.85	$1.85
Customer-Owned	25000	4,236	100	423,600	N/A	N/A	$2.31	$2.31
Customer-Owned	46000	12	164	1,968	N/A	N/A	$3.79	$3.79

2013
RATE CLASS OS

(1)	(2)	(3)	(4)	(5)	(11)	(12)	(13)	(14)
					Rates			
Type of Facility	Description	Annual Billing Items	Est. Monthly KWH	Annual KWH	Facility Charge	Maintenance Charge	Energy Charge	Total Monthly Charge
ADDITIONAL FACILITIES								
13 Ft. Decorative Concrete Pole		33,720	N/A	N/A	N/A	N/A	N/A	$15.95
17 Ft. Decorative Base Aluminum Pole		132	N/A	N/A	N/A	N/A	N/A	$16.72
20 Ft. Fiberglass Pole		26,424	N/A	N/A	N/A	N/A	N/A	$5.92
30 Ft. Wood Pole		30,672	N/A	N/A	N/A	N/A	N/A	$3.83
30 Ft. Concrete Pole		62,352	N/A	N/A	N/A	N/A	N/A	$8.03
30 Ft. Fiberglass Pole w/Pedestal		684	N/A	N/A	N/A	N/A	N/A	$38.01
35 Ft. Concrete Pole		1,500	N/A	N/A	N/A	N/A	N/A	$11.70
35 Ft. Tenon Top Concrete Pole		1,668	N/A	N/A	N/A	N/A	N/A	$16.15
35 Ft. Wood Pole		63,768	N/A	N/A	N/A	N/A	N/A	$5.58
40 Ft. Wood Pole		1,128	N/A	N/A	N/A	N/A	N/A	$6.86
45 Ft. Concrete Pole (Tenon Top)		1,968	N/A	N/A	N/A	N/A	N/A	$21.20
Single Arm - Shoebox		804	N/A	N/A	N/A	N/A	N/A	$2.22
Double Arm - Shoebox		132	N/A	N/A	N/A	N/A	N/A	$2.47
Tenon Top Adapter		636	N/A	N/A	N/A	N/A	N/A	$4.11
Optonal 100 Amp Relay		72	N/A	N/A	N/A	N/A	N/A	$22.97
Miscellaneous Additional Facilities		$659,714.84	N/A	N/A	N/A	N/A	N/A	N/A

Schedule 10

Gulf Power Company
Monthly 1,000 Kilowatt-Hour Residential Electric Bill

	Prior to interim	Interim effective September 22, 2011	Effective April 11, 2012	Increase/ (Decrease)*
Base Rates:				
Customer Charge	$10.00	$10.89	$15.00	$5.00
Energy Charge	$39.30	$42.79	$42.65	$3.35
Subtotal Base Rates	$49.30	$53.68	$57.65	$8.35
Adjustment Clauses:				
Fuel and Purchased Power	$51.31	$51.31	$46.44	($4.87)
Energy Conservation Cost	$0.80	$0.80	$2.56	$1.76
Environmental Cost	$13.43	$13.43	$12.94	($0.49)
Capacity Cost	$4.76	$4.76	$3.78	($0.98)
Subtotal Adjustment Clauses	$70.30	$70.30	$65.72	($4.58)
Gross Receipts Taxes	$3.07	$3.18	$3.16	$0.09
Total Monthly Bill	**$122.67**	**$127.16**	**$126.53**	**$3.86**

*compared to prior to interim

Gulf Power Company
Total Residential Bill Comparisons by kWh Usage

Usage	Prior to interim	Interim	Effective April 2012
1,000 kWh	$122.67	$127.16	$126.53
1,200 kWh	$145.15	$150.36	$148.77
1,500 kWh	$178.88	$185.17	$182.11
2,000 kWh	$235.08	$243.15	$237.67
3,000 kWh	$347.49	$359.14	$348.83