BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160186-EI

PETITION FOR RATE INCREASE BY GULF POWER COMPANY.
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DOCKET NO. 160170-EI

PETITION FOR APPROVAL OF 2016 DEPRECIATION AND DISMANTLEMENT STUDIES, APPROVAL OF PROPOSED DEPRECIATION RATES AND ANNUAL DISMANTLEMENT ACCRUALS AND PLANT SMITH UNITS 1 AND 2 REGULATORY ASSET AMORTIZATION, BY GULF POWER COMPANY.
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VOLUME 3
(Pages 506 through 759)

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN JULIE I. BROWN COMMISSIONER ART GRAHAM COMMISSIONER RONALD A. BRISÉ COMMISSIONER DONALD J. POLMANN
DATE:	Monday, March 20, 2017
TIME:	Commenced at 1:00 p.m. Concluded at 2:53 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, CRR, RPR Official FPSC Reporter (850) 413-6734
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER: ID.
ADMTD.

No exhibits in this volume

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Ritenour
Docket No. 160186-EI
In Support of Rate Relief
Date of Filing: October 12, 2016

Q. Please state your name and business address.

A. My name is Susan Ritenour. My business address is One Energy Place, Pensacola, Florida 32520.

Q. By whom are you employed?

A. I am employed by Gulf Power Company (Gulf or the Company) as Corporate Secretary, Treasurer and Corporate Planning Manager.

Q. What are your responsibilities as Gulf's Corporate Secretary, Treasurer and Corporate Planning Manager?

A. I am responsible for Gulf's overall planning and budgeting process and the resulting financial forecast. This includes the ongoing development and maintenance of the Operations and Maintenance (O&M) and Capital Additions Budgeting Systems and other financial forecasting models and projections. The Corporate Planning Department also provides decision support and financial analyses for Gulf's management and business units. In addition, I am responsible for various treasury and corporate secretary activities.

Q. Please describe your educational and professional background.
A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf in 1983 as a Financial Analyst and have held various positions of increasing responsibility, including Computer Modeling Analyst, Senior Financial Analyst, Supervisor of Rate Services, and Assistant Secretary and Assistant Treasurer. Prior to assuming my current responsibilities in September 2012, I held the position of Secretary and Treasurer and Regulatory Manager since September 2003.

Q. What is the purpose of your testimony?
A. Using the financial forecast discussed by Gulf Witness Mason and the jurisdictional factors from the cost-of-service study discussed by Gulf Witness O'Sheasy, I develop the test year jurisdictional adjusted rate base, net operating income and capital structure, and calculate the resulting retail base rate revenue deficiency, which the Company has identified in this filing. My testimony supports the calculation of certain adjustments to the rate base and net operating income, including a hiring lag adjustment, adjustments to reflect the amortization of the remaining investment in Plants Smith and Scholz, and adjustments necessary to reflect the amortization of the deferred return on certain transmission capital projects. I also present and support Gulf's O&M Expense Benchmark calculations and the General Plant capital additions budget and investment. Finally, I support the

calculations of the amounts associated with off-system sales made from Gulf's ownership portion of Plant Scherer Unit 3 (Scherer 3).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit SDR-1, Schedules 1 through 24. Exhibit SDR-1 was prepared under my supervision and direction, and the information contained in the exhibit is true and correct to the best of my knowledge and belief.

Q. Are you also sponsoring any of the Minimum Filing Requirements (MFRs) filed by Gulf?

A. Yes. The MFRs that I sponsor in their entirety and that I jointly sponsor are listed on Schedule 1 of Exhibit SDR-1. To the best of my knowledge and belief, all of the information presented in the MFRs that I sponsor or co-sponsor is true and correct.

I. RATE BASE

Q. Have you prepared a schedule which shows the derivation of rate base?

A. Yes. Exhibit SDR-1, Schedule 2, entitled "13-Month Average Rate Base for the Period Ended December 31, 2017," reflects Gulf's test year rate base. Column 1 is calculated based on the budget data presented on Schedules 7 and 9 of Mr. Mason's Exhibit JJM-1. The second column includes the regulatory adjustments required in order to restate the system, or per books, amounts to the proper basis for computing base rate revenue requirements. The third column reflects amounts associated with the portion of Scherer 3 investment that is committed to off-system sales. I will discuss the calculation of these amounts later in my testimony. The resulting net amounts in column 4 have been jurisdictionalized in the cost-of-service study filed in this case by Mr. O'Sheasy in Exhibit MTO-2.

Q. Have you made the proper adjustments to remove the investment related to the cost recovery clauses from rate base?

A. Yes. These and other rate base adjustments are listed on page 2 of Schedule 2 of Exhibit SDR-1. Adjustments 1, 2, 8, 9 and 19 are to remove the plant-in-service, accumulated depreciation, and non-interest bearing construction work in progress (CWIP-NIB) being recovered through the Environmental Cost Recovery Clause (ECRC) and the Energy Conservation Cost Recovery (ECCR) Clause. I have also removed the working capital recovered through the ECRC and ECCR Clauses in adjustment 23 as shown on Exhibit SDR-1, Schedule 3. The investments that are being recovered through the adjustment clauses must be excluded in developing the rate base used to establish Gulf's base rates.

Q. Please explain adjustments 3 and 10 related to Asset Retirement Obligations (AROs).

A. Adjustments 3 and 10 are to remove the plant-in-service and accumulated depreciation amounts related to Accounting Standards Codification (ASC) 410, Asset Retirement and Environmental Obligations (AROs). This accounting standard requires the Company to record an asset and the related liabilities and expenses associated with the legal obligations related to the retirement of long-lived assets. I have also removed the regulatory assets and liabilities related to ASC 410 in the working capital adjustments as shown on Schedule 3. The adjustments to remove these amounts are necessary to eliminate the impact of these accounting entries in accordance with Florida Public Service Commission (FPSC or Commission) Rule 25-14.014, which requires that the application of this accounting standard be revenue neutral.

Q. Please describe adjustments 4 and 11 related to the Community Solar Project.

A. Adjustments 4 and 11 remove the plant-in-service and accumulated depreciation related to the Community Solar Project. The costs of this project will be recovered through fees paid by the participants in the project.

Q. Please explain the adjustments to plant-in-service, accumulated depreciation, and construction work in progress related to generation, power delivery and customer service projects.

A. Adjustments 5 through 7, 12 through 14, and 20 through 22 are made to reflect changes to projected capital projects that arose following the completion of the Company's budget on which the 2017 test year is based. Gulf Witnesses Burroughs, Smith and Terry will discuss the generation, power delivery and customer service projects, respectively, in more detail in their testimonies, including the total costs of the projects. I have calculated the depreciation expense and related accumulated depreciation associated with the projects based on the proposed depreciation rates requested by Gulf in this docket as supported in the testimony of Gulf Witness Hodnett.

Q. Please describe adjustment 15 related to the retirement of Plant Smith Units 1 and 2.

A. As discussed by Mr. Burroughs in his testimony, Gulf retired its coal-fired units at Plant Smith in March of 2016. On February 24, 2016, Gulf filed a petition with the Commission seeking authority to create a regulatory asset related to the remaining inventory and net book value of Smith Units 1 and 2 at retirement and defer recovery until a future proceeding. The Commission approved the Company's petition on August 29, 2016 in Order No. PSC-16-0361-PAA-EI as amended by Order No. PSC-16-0361A-PAA-EI in Docket No. 160039-EI. Gulf has made the appropriate entries on its books and records to establish the regulatory asset. Gulf is requesting that this regulatory asset be amortized over 15 years, the time period from the 2017 test year to the normal retirement date of Smith Unit 2 (2032), which is the later of the retirement dates of the two units. The portion of the regulatory asset that is associated with the plant investment that was recovered through the ECRC while the units were in service will be recovered through the ECRC. Adjustment 15 on Schedule 2 is made to remove the base rate portion of the projected net book value of Smith 1 and 2 from accumulated depreciation. On Schedule 3 of my exhibit, I have made adjustments to working capital to remove the projected inventory balance from current assets and to add the base rate portion of the regulatory asset based on the actual net book value and inventory amounts as of the retirement date. The adjustment to include the regulatory asset on Schedule 3 reflects the 13-month average unamortized balance of the base rate portion of the regulatory asset assuming a 15-year amortization period. The calculation of the amounts included in the regulatory asset is shown on Schedule 9. The working capital adjustments associated with Smith 1 and 2 are included in adjustment 23 on page 2 of Schedule 2.

Q. Please describe adjustment 16 to accumulated depreciation associated with the Cost of Removal provisions approved pursuant to the Settlement in Gulf's last rate case in Docket No. 130140-EI.

A. The Stipulation and Settlement Agreement (2013 Settlement Agreement) approved by the Commission in Gulf's last rate case in Order No. PSC-13-0670-S-EI provided Gulf with the discretion to record credits to depreciation expense up to $62.5 million over the life of the 2013 Settlement Agreement, with an offsetting entry to a regulatory asset referred to as Other Cost of Removal. In any given month, the credit to depreciation expense could not exceed the amount necessary for the retail return on equity (ROE) to reach the midpoint of the authorized ROE range. Over the course of the 2013 Settlement Agreement period, Gulf will have recorded $62.5 million to this regulatory asset. As provided for in the 2013 Settlement Agreement, Gulf has proposed offsetting this regulatory asset against the accumulated reserve for fossil generating plant dismantlement as discussed in the testimony of Ms. Hodnett. Rate base adjustment 16 is required to include the regulatory asset in accumulated depreciation. I have also made an adjustment to working capital on Schedule 3 to reflect the removal of the 13-month average regulatory asset balance. This is included in adjustment 23 on Schedule 2, page 2.

Q. Please describe adjustment 17 related to the 2016 Depreciation Study and 2016 Dismantlement Study.

A. Adjustment 17 reflects the impact on accumulated depreciation of new depreciation rates and dismantlement expense. Ms. Hodnett discusses the 2016 Depreciation Study and 2016 Dismantlement Study in her testimony and has provided the updated information required to determine the impact of these studies on Gulf's depreciation and dismantlement expense in the 2017 test year.

Q. Please explain adjustment 18 related to interest bearing construction work in progress.

A. Adjustment 18 is for the removal of the interest bearing construction work in progress (CWIP), since interest bearing projects in CWIP are eligible for Allowance for Funds Used During Construction (AFUDC). None of the construction projects included in the 2017 test year are eligible for AFUDC based on FPSC Rule 25-6.0141, Allowance for Funds Used During Construction. Therefore, the amount of this adjustment is $0.

Q. Please explain the working capital adjustments included in adjustment 23.

A. The working capital adjustments which comprise adjustment 23 are detailed on Schedule 3 of Exhibit SDR-1, entitled "13-Month Average Working

Capital for the Period Ended December 31, 2017." Gulf has computed the test year working capital requirement utilizing the balance sheet approach in accordance with this Commission's policy and prior practices. All items on the balance sheet which are not included in Net Utility Plant or the Capital Structure were considered in developing working capital. These items are summarized at the top of the schedule and result in $87,230,000 in total company working capital. Each of these items was examined to determine if a regulatory adjustment should be made to remove it from working capital. As a result of this review, I have excluded the amounts related to the ECRC and ECCR, all accounts which earn or incur interest charges, and the ARO regulatory assets and liabilities I discussed previously. I have also reduced working capital to reflect the impact of the increase in the property damage reserve accrual discussed by Ms. Hodnett in her testimony. As I discuss in more detail below, I have also adjusted working capital for deferred earnings associated with certain transmission investments, inventory at Plant Scholz, and additional pension funding.

The other adjustments noted in Schedule 3 remove the assets and liabilities related to Gulf's fuel hedging under ASC 815, Derivatives and Hedging, which are ultimately recovered through the Fuel Cost Recovery (FCR) Clause, and remove the minimum pension funding requirements under ASC 715, Compensation – Retirement Benefits, which requires the recording of certain minimum pension funding requirements. In addition, I have removed the assets and liabilities related to the levelization of capacity expenses related to power purchase agreements (PPAs), which are required by general accounting guidance. The adjustments to total assets and liabilities for the ASC 815, ASC 715, and PPA entries net to zero, and they have been removed from the working capital amounts provided to Mr. O'Sheasy to be jurisdictionalized in the cost-of-service study.

Q. Please explain the adjustment to working capital related to the deferred earnings associated with certain transmission investments.

A. Pursuant to the 2013 Settlement Agreement approved by the Commission in Gulf's last rate case in Docket No. 130140-EI, Gulf has accrued deferred earnings equivalent to the AFUDC rate on certain transmission projects identified in the Agreement. These deferred earnings are included in the Company's working capital as a deferred debit. The 2013 Settlement Agreement provides that the specified transmission investment, AFUDC, and the deferred earnings be added to rate base for surveillance and ratemaking purposes at the conclusion of the period during which the accrual of deferred earnings applies, which is January 1, 2017. In this proceeding, Gulf is requesting that the deferred debit representing the accumulated deferred earnings be amortized over four years, consistent with the period customarily used by the Commission for amortization of rate case expense. Schedule 10 of my exhibit shows the calculation of the amortization based on the projected balance of the deferred debit as of December 31, 2016.

Q. Please explain the working capital adjustment related to Plant Scholz materials and supplies.

A. As Mr. Burroughs discusses in his testimony, Gulf's two generating units at Plant Scholz ceased operations on April 15, 2015, and while Gulf has taken appropriate measures to minimize equipment inventory, $609,000 of inventory remains. This investment was prudently incurred in providing electric service to our customers from Plant Scholz. Therefore, Gulf is requesting that this remaining inventory be transferred to a regulatory asset and amortized over four years, the period normally used by the Commission for amortization of rate case expense. The working capital adjustments shown on Schedule 3, and included in adjustment 23 on Schedule 2, are made to remove the inventory from current assets and include the 13-month average unamortized balance in deferred debits.

Q. Please explain the adjustments to Other Property and Investments and Current Liabilities related to additional pension funding.

A. As discussed in the testimony of Gulf Witness Garvie, Gulf projects to provide additional funding to the pension plan. The adjustments to Other Property and Investments and Current Liabilities reflect the total additional funding of $81 million.

Q. What is the total of the regulatory adjustments to working capital?

A. The net of all regulatory adjustments to total working capital is $176,677,000, which is shown in column 2 on page 1 of Schedule 2 as adjustment 23. The total system adjusted working capital of $262,068,000 (column 4, page 1 of Schedule 2) resulted in jurisdictional adjusted working capital of $256,171,000 (column 6, page 1 of Schedule 2) as derived by Mr. O'Sheasy in the cost-of-service study.

Q. What is the total jurisdictional rate base for the 2017 test year after all the appropriate adjustments have been made?

A. As shown on page 1 of Schedule 2 of Exhibit SDR-1, the total jurisdictional adjusted rate base is $2,418,917,000. This represents the used and useful base rate investment which is required to provide service for Gulf's retail customers, and all these costs were reasonably and prudently incurred.

II. NET OPERATING INCOME

Q. Please explain Exhibit SDR-1, Schedule 4 entitled "Net Operating Income for the Twelve Months Ended December 31, 2017."

A. This schedule is formatted in the same manner as the rate base schedule. Page 1 provides the calculation of the test year net operating income. The first column on page 1 of Schedule 4 is calculated based on the 2017 budget data from Schedule 8 of Mr. Mason's Exhibit JJM-1. The second column includes the regulatory adjustments, which are detailed on pages 2 and 3 of Schedule 4, with more detailed calculations presented on separate schedules as noted under the heading of Schedule Reference on pages 2 and 3. The third column reflects amounts associated with the portion of Scherer 3 that is committed to off-system sales. I will discuss the calculation of these amounts later in my testimony. The jurisdictional adjusted amounts in column 6 were obtained from Mr. O'Sheasy's Exhibit MTO-2.

Q. Have you made the proper adjustments to remove all revenues and expenses related to the cost recovery clauses from NOI?

A. Yes. The appropriate adjustments to remove the revenues (adjustments 1 through 4) and expenses (adjustments 9 through 15, 30, 31, 40, and 41) related to the retail cost recovery clauses are included on pages 2 and 3 of Schedule 4. Additional details supporting each cost recovery clause adjustment are provided on Schedules 5 through 8 of Exhibit SDR-1. These revenues and expenses are considered in the retail cost recovery clauses; therefore, they must be removed from the test year amounts used for determining base rates. As reflected on Schedules 5 through 8, the system amounts have been removed from NOI in Schedule 4, and I have also reflected the jurisdictional amounts for each cost recovery clause.

Q. Please explain the franchise fee and gross receipts adjustments 5, 6, 43 and 44 on Schedule 4.

A. These adjustments are necessary to eliminate county and municipal franchise fee revenues and expenses and gross receipts taxes from consideration in setting base rates. As required by Commission Order No. 6650 in Docket No. 74437-EU, franchise fees are added directly to the county or municipal customer's bill. Florida gross receipts taxes were removed from base rates in Gulf's rate case in Docket No. 010949-EI and are separately calculated and shown on the customer's bill.

Q. Please explain revenue adjustments 7 and 8.

A. As Ms. Terry discusses in her testimony, Gulf plans to support customers who are interested in electric vehicles (EV) and electric vehicle charging by purchasing, installing and supporting EV chargers at customers' locations. The investment and expenses are included in the 2017 test year amounts; adjustment 7 is required to include the revenues from electric vehicle chargers that we project to receive in the 2017 test year. As discussed in Ms. Hodnett's testimony, adjustment 8 is required to correct an error in the amount of miscellaneous service revenues projected to be received in the 2017 test year.

Q. Please explain adjustment 16 related to marketing support activities and adjustment 17 related to wholesale sales activities.

A. Expenses related to marketing support activities (adjustment 16) have been removed from NOI in accordance with the Commission's policy to disallow expenses that are promotional in nature as stated in Commission Order No. 6465 in Docket No. 9046-EU. Expenses related to wholesale sales activities (adjustment 17) were also removed from NOI in the calculation of retail revenue requirements, since these expenses relate directly to activities supporting Gulf's wholesale customers.

Q. Please explain adjustments 18 and 19 related to institutional advertising and economic development expenses.

A. Consistent with prior Commission decisions, adjustment 18 removes the test year amount of institutional or image building advertising. All other advertising is either recovered in the ECCR clause or meets the criteria for recovery in base rates and is included in the O&M expenses supported by Ms. Terry in this proceeding.

Adjustment 19 removes 5 percent of the 2017 test year expenses related to economic development expenses. This treatment is consistent with the Commission's decision in Gulf's 2012 test year rate case, and Ms. Terry will support the reasonableness of the test year amount.

Q. Please explain adjustments 20, 22, and 42.

A. These adjustments remove the expenses related to management financial planning services (adjustment 20) and the Tallahassee liaison expenses (adjustments 22 and 42), consistent with the Commission's decision in Gulf's 2012 test year rate case.

Q. Please explain adjustment 21 related to the property damage reserve accrual.

A. Gulf is requesting an increase to the annual property damage reserve accrual from the current approved amount of \$3.5 million to \$8.9 million based on the current hurricane storm damage study performed by Gulf Witness Harris and the non-hurricane property damage assessment performed by Ms. Hodnett. The need for this increase and the amount of the accrual are supported by Ms. Hodnett in her testimony.

Q. Please explain adjustment 23 related to the recovery of Gulf's rate case expenses.

A. As reflected in MFR C-10, Gulf estimates the incremental expenses related to this rate case filing will be $6.7 million, as discussed by Ms. Hodnett. Gulf is requesting to amortize these expenses over a four-year period, which is consistent with the Commission's recent decisions regarding the appropriate period over which to amortize rate case expenses.

Q. Please describe the hiring lag adjustment to O&M (adjustment 24).

A. The hiring lag adjustment of $863,000 quantifies the impact on salaries and benefits of potential employee turnover. A more detailed description and calculation of this adjustment is included later in my testimony.

Q. Please explain adjustments 25 through 29 related to production, power delivery, Long Term Evolution (LTE) system, customer service and pension O&M expense.

A. These adjustments are necessary to reflect changes to projected O&M expenses that arose following the completion of the Company's budget on which the 2017 test year is based. Mr. Burroughs, Mr. Smith, Ms. Terry, and Mr. Garvie support and explain the changes to these expenses in their testimonies.

Q. Please explain adjustment 32 related to depreciation and dismantlement expense.

A. Adjustment 32 reflects the impact of the 2016 Depreciation Study and the 2016 Dismantlement Study on Gulf's depreciation and dismantlement expense in the 2017 test year.

Q. Please explain adjustments 33 through 36 to depreciation expense.

A. Adjustment 33 removes the depreciation expense associated with Gulf's Community Solar Project. As I discussed earlier in my testimony, the costs of this project will be recovered through fees paid by the participants in the project. Adjustments 34 through 36 are made to reflect the depreciation expense associated with the changes to generation, power delivery and customer service projects that I discussed earlier in my testimony.

Q. Please explain adjustments 37, 38 and 39.

A. As I discussed earlier in my testimony, Gulf is requesting amortization of three items: the remaining investment in Plant Smith Units 1 and 2, the deferred earnings on certain transmission investment, and the investment in inventory remaining at Plant Scholz. Adjustments 37, 38 and 39 are the amortization amounts associated with these three items. Schedules 9 and 10 show the calculation of the amortization associated with the Smith and transmission investments, respectively. As I discussed earlier in my testimony, Gulf is requesting that the remaining inventory at Plant Scholz of $609,000 be amortized over four years.

Q. Please explain adjustment 45 to taxes other than income taxes.

A. Adjustment 45 is required to remove the FPSC regulatory assessment fees that are associated with the retail revenues and franchise fee revenues removed in adjustments 1 through 5, 7 and 8. Schedule 11 of Exhibit SDR-1 shows the calculation of this adjustment.

Q. Please explain adjustment 46 to income taxes on page 3 of Schedule 4.

A. This adjustment is required to reflect the federal and state income tax effects of adjustments 1 through 45. Schedule 12 of Exhibit SDR-1 shows the calculation of this adjustment.

Q. Have you calculated the appropriate adjustment to income taxes to reflect the synchronized interest expense related to the jurisdictional adjusted rate base?

A. Yes. Adjustment 47 on Schedule 4 reflects the tax effect of synchronizing interest expense to rate base, and Exhibit SDR-1, Schedule 13 shows the calculation of this adjustment. Consistent with prior Commission practice, the synchronized interest expense is computed by multiplying the jurisdictional adjusted rate base by the weighted cost of debt included in the cost of capital. This adjustment ensures that the calculated revenue requirements reflect the appropriate tax deduction for the interest component of the revenue requirement calculation. The jurisdictional capitalization amounts and cost rates were taken directly from Exhibit SDR-1, Schedule 14, and total company interest expense was taken from the projected income statement shown on Schedule 8 of Mr. Mason’s Exhibit JJM-1.

Q. Please summarize Gulf's adjusted O&M request included in the 2017 test year.

A. The Company's total test year adjusted O&M request is $319,813,000. As discussed in the testimony of the Company's functional witnesses, the O&M request is reasonable, prudent and necessary to provide reliable electric service to our customers.

Q. What is the total jurisdictional NOI for the 2017 test year after all the appropriate adjustments have been made?

A. Gulf's jurisdictional NOI for 2017 is $80,723,000.

III. JURISDICTIONAL CAPITAL STRUCTURE

Q. Have you developed the jurisdictional adjusted capital structure and cost of capital for the test year?

A. Yes. Schedule 14, page 1, of Exhibit SDR-1 shows the jurisdictional 13-month average amounts of each class of capital for the test year ended December 31, 2017. It also shows the average cost rates and weighted cost components for each class of capital. Page 2 of this schedule shows how the jurisdictional adjusted capital structure was derived starting with the system amounts in column 1. Page 3 shows the calculation of the weighted cost rate for long-term debt, and page 4 shows the calculation of the weighted cost rate for preference stock.

Q. How were the cost rates for long-term debt, preference stock, short-term debt, customer deposits, and investment tax credits determined?

A. The cost rates for long-term debt and preference stock reflect their embedded 13-month average costs as calculated on pages 3 and 4 of Schedule 14. The projected interest rate assumptions used in the financial forecast are shown in MFR F-8. The assumptions used in the forecast were provided by Southern Company Services Financial Planning and were based on a market forecast by Moody's Analytics. The weighted customer deposit cost rate of 2.30 percent was based on the interest rates required pursuant to FPSC Rule 25-6.097, Customer Deposits. The cost for investment tax credits of 8.05 percent was calculated in accordance with current IRS regulations and prior Commission practice, using the weighted average of the three main investor sources of capital.

Q. Please explain how the jurisdictional capital structure was developed.

A. As shown on page 2 of Schedule 14, I started with the 13-month average total company capital structure by class of capital for the test year ended December 31, 2017. These total company amounts were calculated based on the projected balances for each item in the capital structure from the balance sheet shown on Schedule 7 of Mr. Mason's Exhibit JJM-1. In columns 2 through 5 and 8, I have identified six adjustments which were removed from specific classes of capital. Column 6 provides the adjustments to long-term debt and common equity necessary to reflect the issuance of $150 million of common stock as discussed in the testimony of Gulf Witness Liu. Column 9 contains the adjustments required to comply with the normalization requirements of the Internal Revenue Code. The remaining adjustments required to reconcile the rate base and capital structure were made on a pro rata basis as shown in column 12.

Q. Please explain the six items for which you have made adjustments to specific classes of capital in columns 2 through 5 and 8 on Schedule 14.

A. As shown in columns 2 and 3 on page 2, common dividends declared and unamortized debt premiums, discounts, issuing expenses and losses on reacquired debt are account specific and have been directly assigned to the common stock and long-term debt classes of capital, respectively. In addition, column 2 also includes an adjustment related to the common equity portion of the AFUDC-like return on certain transmission investments pursuant to the 2013 Settlement Agreement. The fourth item, shown in column 4, is the removal of non-utility amounts from the common stock class of capital consistent with past Commission policy. The fifth item shown in column 5 reclassifies the unamortized loss related to interest rate hedges from common equity and deferred taxes to long-term debt. The last item, shown in column 8, is the removal of the capital structure amounts related to the portion of Scherer 3 investment that is currently committed to off-system sales. I specifically identified the deferred taxes and investment tax credits related to this portion of Scherer 3 and then allocated the remaining investment over the other external sources of funds.

Q. Please explain the deferred tax adjustment shown in column 9, as calculated on Schedule 15.

A. This adjustment is necessary to comply with the normalization requirements of the Internal Revenue Code (IRC), which are set forth in Treasury Regulation Section 1.167(1) – 1(h)(6). When a projected test year is used in determining a utility's revenue requirement, the IRC requires that deferred taxes related to accelerated depreciation be calculated using a proration formula. This formula applies to the portion of the test year that coincides with the period that new rates will be in effect. For this portion of the test year, the addition to deferred taxes is prorated as shown on Schedule 15 of Exhibit SDR-1 beginning in July of 2017, which is when new base rates are expected to become effective. The current month activity shown in column 2 is multiplied by the future days in the test period for that month as shown in column 5 and then divided by the total days to prorate shown in column 4 to derive the prorated monthly activity. The decrease to deferred taxes of $747,000 shown in column 9 on page 2 of Schedule 14 is derived by taking the difference between the 13-month average deferred taxes on the books of the company and the 13-month average deferred taxes calculated using the proration formula prescribed by the IRC. The other sources of capital are increased in column 9 on a pro rata basis to offset this adjustment to deferred taxes.

Q. Why is it appropriate to make the remaining rate base adjustments (shown in column 12) on a pro rata basis?

A. When reconciling capital structure to rate base, it is appropriate and necessary to include all sources of funds to avoid potential inconsistencies in the treatment of like expenditures for regulatory purposes. The pro rata treatment is consistent with prior Commission practice and tax normalization problems could result if the treatment is not consistent for all regulatory purposes. Current Commission practice provides an overall return in the cost recovery clauses and AFUDC rate computations; therefore, the base rate treatment should be consistent with these other regulatory requirements to avoid normalization problems and inconsistent regulatory treatment.

Q. Does this conclude your discussion of how you developed the jurisdictional adjusted cost of capital?

A. Yes. These calculations, which are detailed in Schedule 14 of Exhibit SDR-1, result in a cost of capital of 6.04 percent based on a requested return on equity of 11.00 percent, which is supported in the testimony of Gulf Witness Vander Weide.

IV. O&M BENCHMARK ANALYSIS

Q. Has the Company prepared an O&M Benchmark variance by function?

A. Yes. The Benchmark variance by function is included in MFR C-41, and Schedule 19 of Exhibit SDR-1 shows the functional summary for the test year. As shown on Schedule 19, the Company's total adjusted O&M of $319,813,000 for the test year is $10,282,000 over the Benchmark. The justifications for each functional variance are included in MFR C-41 and are addressed by the appropriate Company witnesses.

Q. Please explain how the Benchmark variances were calculated.

A. The first step in the calculation of the Benchmark variances is to determine the base year O&M amounts. The appropriate base year for the Benchmark is the 2012 test year approved by the Commission in Docket No. 110138-EI. This is appropriate because Gulf's last rate case proceeding was resolved through a settlement that did not include specific O&M amounts. The derivation of the 2012 allowed amounts by function is included in MFR C-39 and Schedule 20 of Exhibit SDR-1. The adjustments in columns 2 through 6 of Schedule 20 include the system amount of the Company and Commission adjustments, and column 7 reflects the system allowed O&M by function. This amount is included in column 1 of Schedule 19 of my exhibit.

The second step is to escalate these base year amounts by the compound multipliers noted in column 2 of Schedule 19 in order to derive the Test Year Benchmark amounts included in column 3.

The third step is to calculate the adjusted 2017 test year O&M expense request by function included in column 4 of Schedule 19. The derivation of these figures is shown on MFR C-38 and Schedule 21 of my exhibit.

The final step is to compare the 2017 test year requested O&M in column 4 of Schedule 19 to the Test Year Benchmark in column 3 in order to calculate the variance shown in column 5.

Q. How is the Benchmark used to evaluate the reasonableness of O&M expenses?

A. The Benchmark methodology escalates the base year approved expenses for each function by customer growth (except for Production) and inflation, as measured by the Consumer Price Index (CPI). If the projected test year expenses for any function exceed the Benchmark, this triggers a requirement that the Company explain the reasons for the variance. The Benchmark is thus a tool used to identify specific expense amounts that warrant further explanation and justification of the reasonableness of the test year request during the course of a rate case.

V. HIRING LAG

Q. How many employees are included in Gulf's test year request?
A. Gulf's test year request includes a full complement of 1,450 employees for 2017. This is a net reduction of 39 positions compared to the complement of 1,489 employees requested in Gulf's 2012 test year rate case in Docket No. 110138-EI.

Q. Even if Gulf makes every effort to fill all employee positions, won't some positions be temporarily unfilled for part of the year due to voluntary and involuntary separations, retirements, deaths, transfers within the Southern Company system, and transfers within Gulf?
A. Yes. This type of hiring lag is found in any business.

Q. Should the Commission make a labor expense adjustment in this case to account for that lag?
A. In the normal course of business, any unspent payroll dollars resulting from hiring lag will most likely be spent on contract labor, overtime, or other operational priorities. Although the Company does not believe a labor adjustment is necessary or appropriate, Gulf has included an adjustment to labor in the current proceeding to be consistent with prior Commission practice of making such adjustments.

Q. How did you calculate this adjustment?

A. The hiring lag adjustment takes into account Gulf's estimated employee turnover, the average time it takes to fill a position, and the average salary for the unfilled positions. The calculation of the adjustment is shown on Schedule 22 of Exhibit SDR-1. The average employee turnover (including voluntary and involuntary terminations, retirements and system transfers) and the average time it has taken to fill positions were derived based on the Company's historical records for 2012 through 2015. The hiring lag base salary amount was derived by multiplying the average turnover by the number of days to fill positions times the salary level by employee classification as shown on Schedule 22. This calculation resulted in a total base salary hiring lag of $834,975. Of this amount, $618,800 represents the O&M portion, which I then increased to include the estimated fringe benefits and variable compensation, resulting in a total hiring lag adjustment of $862,731.

VI. GENERAL PLANT INVESTMENT

Q. Schedule 2 of Exhibit SDR-1 shows a total of $3.458 billion of plant-in-service investment in Gulf's 2017 rate base in this case. Are the General Plant assets associated with these costs used and useful in the provision of electric service to the public?

A. Yes. The General Plant assets of $201,302,000 included in plant-in-service are used and useful in the provision of electric service.

Q. Were these General Plant costs reasonable and prudently incurred?

A. Yes. All General Plant projects are subject to the review and approval process and cost control monitoring which govern our capital budgeting process as described in Mr. Mason's testimony.

Q. What is Gulf's projected General Plant capital additions budget for 2016 and 2017?

A. As shown on Schedule 23 of Exhibit SDR-1, Gulf's General Plant capital additions budget for 2016 is $14,738,000 and for 2017 is $22,148,000. The major items included in the 2017 test year are:

- Automobiles, Trucks and Equipment $ 3,360,000
- Gulf Smart Energy Center $ 3,000,000
- Office Facility Capital Items $ 1,048,000
- Information Technology (IT) Projects $ 1,645,000
- Long-Term Evolution (LTE) System $11,400,000
- Customer Service Projects $ 698,000
- Other Projects $ 997,000

Q. Please address what is included in the General Plant capital budget and how it is developed.

A. The General Plant capital budget items include the investment in facilities and equipment not specifically provided for in the other functional accounts. The major types of investment include office buildings and related office furniture and equipment, transportation equipment, communication equipment, and other miscellaneous equipment. The budget requests for these types of investment are coordinated and submitted at a Company level by the responsible functional area. Mr. Smith discusses the capital additions for automobiles, trucks and equipment along with other General Plant capital additions that primarily support the power delivery business units. Ms. Terry discusses the capital additions related to customer service projects. The General Plant requests are included in the executive capital budget review and approval process.

Q. How does Gulf control General Plant capital costs after the capital budget is approved?

A. As Mr. Mason discusses in his testimony, detailed explanations are required quarterly for project variances of greater than 10 percent or $250,000 (whichever is lower). Variances less than $10,000 do not require variance explanations.

VII. SCHERER UNIT 3 OFF-SYSTEM SALES

Q. You have previously mentioned that you are supporting the adjustments related to Scherer 3 off-system sales that have been used in developing the rate base, NOI and capital structure in this filing. Please explain how these amounts were calculated.

A. The amount of investment and expenses associated with Scherer 3 has been computed consistent with the methodology used in Gulf's last four rate cases when 100 percent of Scherer 3 was sold off-system. In the 2017 test year, 24 percent of Scherer 3 is committed to off-system sales. The remaining 76 percent of Scherer 3 is dedicated to serving the native load customers for whom it was originally planned, acquired, and ultimately built. To determine the amount of investment and expenses related to the portion of Scherer 3 committed to off-system sales, I multiplied the components of Scherer 3 investments and expenses by 24 percent. In addition, certain working capital investment was allocated to Scherer 3 off-system sales in the cost of service study consistent with past Commission treatment. The calculation of the Scherer 3 off-system sales rate base and net operating income is shown on Schedule 24 of my exhibit. The Scherer 3 off-system sales capital structure was determined by directly assigning 24 percent of the deferred taxes and unamortized ITC associated with Scherer 3. The remaining rate base was allocated to external sources of capital pro rata to derive the total capital structure associated with Scherer 3 off-system sales.

VIII. REVENUE DEFICIENCY

Q. Based on the 2017 jurisdictional adjusted amounts for rate base of $2,418,917,000, NOI of $80,723,000, and the test year cost of capital of 6.04 percent, have you calculated Gulf’s achieved rate of return and return on common equity for the test year if no rate relief is granted?

A. Yes. Without rate relief, Gulf’s achieved rate of return will be 3.34 percent and the achieved return on common equity will be 4.27 percent for the test year, as shown on Schedule 16 of Exhibit SDR-1.

Q. Have you calculated the jurisdictional revenue deficiency for the test period brought about by the difference in Gulf's achieved jurisdictional rate of return of 3.34 percent and the test year cost of capital of 6.04 percent?

A. Yes. The revenue deficiency is $106,782,000, as calculated on Exhibit SDR-1, Schedule 17, which references the schedule where each figure was derived. Schedule 18 of my exhibit shows the calculation of the NOI multiplier, which provides for the income taxes, FPSC Assessment Fees and uncollectible expenses needed in addition to the required after tax NOI in order for the Company to achieve the requested rate of return of 6.04 percent.

IX. SUMMARY

Q. Please summarize your testimony.

A. Gulf's 2017 test year jurisdictional adjusted rate base is $2,418,917,000. This amount represents the retail base rate investments that are used and useful in providing service to Gulf's retail customers during the test year. As described by other witnesses, these investments are reasonable and prudent.

Gulf's total achieved jurisdictional adjusted NOI for the 2017 test year is $80,723,000, absent the rate relief requested in this proceeding. The O&M expenses included in the calculation of NOI are supported by witnesses from each functional area. The projected level of expense is reasonable and prudent to continue to provide reliable electric service to our customers, and it is representative of the level of expenses that will be incurred in the future.

Gulf’s weighted average cost of capital for the test year is 6.04 percent. This cost is based on Gulf’s actual or projected cost of each source of capital and a required return on equity of 11.00 percent as recommended by Dr. Vander Weide. The combination of jurisdictional adjusted rate base, NOI and weighted average cost of capital shows that Gulf requires a retail base revenue increase of $106,782,000 in order to have the opportunity to earn a fair rate of return on its investment in property used and useful in the provision of electric service. This increase is crucial to enable Gulf to make the investments and incur the costs required to continue to provide safe, efficient and reliable service to its customers.

Q. Ms. Ritenour, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
Robert L. McGee, Jr.
Docket No. 160186-EI
In Support of Rate Relief
Date of Filing: October 12, 2016

Q. Please state your name and business address.

A. My name is Bob McGee. My business address is One Energy Place, Pensacola, Florida 32520.

Q. What is your position?

A. I am the Regulatory and Pricing Manager for Gulf Power Company (Gulf or the Company).

Q. What are your responsibilities as Regulatory and Pricing Manager?

A. As Regulatory and Pricing Manager, I am responsible for a team that handles regulatory filings, cost recovery clause filings, pricing and forecasting.

Q. Please state your prior work experience and responsibilities.

A. I began my career in 1984 as a research engineer with Harry Diamond Laboratories, now part of the Army Research Lab, investigating missile fuzing techniques and digital signal processors. Subsequently, I served eight years in the United States Navy as an F-14 Naval Flight Officer, ultimately serving in combat during Desert Storm in 1991. I joined Gulf in 1994 as a Market Analyst working on the forecast, load research, Real Time

Pricing (RTP) and customized metering projects. I have served as a field sales representative to large industrial customers, assistant to a previous Power Generation Vice President, Supervisor of the Instrument & Control team at Plant Crist, Operations Supervisor at Plant Crist, and Market Research and Planning Manager. I have been in my current role since 2012.

Q. What is your educational background?
A. I received a Bachelor of Science degree in Electrical Engineering from the University of Maryland at College Park in 1984. In 1993, I received a Master's degree in Business Administration from the University of West Florida. I have been a Certified Energy Manager since 1998.

Q. What is the purpose of your testimony?
A. My testimony presents a package of improvements to Gulf's residential rates.

Q. Are you sponsoring any exhibits?
A. Yes, I am sponsoring Exhibit RLM-1, Schedules 1 through 7. Exhibit RLM-1 was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge and belief.

Q. Are you sponsoring any of the Minimum Filing Requirements (MFRs) submitted by Gulf?
A. No.

I. CURRENT RESIDENTIAL PRICING

Q. Please describe Gulf's current residential rate offerings.

A. Gulf's standard rate for residential customers is the Residential Service (RS) rate. It is a traditional two-part rate consisting of a Base Charge of $0.62 per day and an Energy Charge of 4.585 cents per kWh (11.4 cents per kWh when combined with current cost recovery clause rates). The Florida Public Service Commission (FPSC or Commission) approved the use of a daily base charge for residential rates in Order No. PSC-13-0670-S-EI, a change that has been well received by Gulf's customers. Gulf has 396,000 residential non-lighting customers, 365,000 of whom are on this standard (or default) residential service rate RS. Gulf currently offers two additional rate options to residential customers: the Residential Service Variable Pricing (RSVP) rate, and the Residential Flat-1 rate. Gulf is also piloting a Residential Service Time-of-Use (RSTOU) rate which has limited availability.

Q. Please describe each of these options in a little more detail.

A. In 1990, with the approval of the FPSC in Docket No. 900090-EG, Gulf developed a first-of-its-kind Critical Peak Pricing (CPP) rate named RSVP to support the Transtext Pilot program which later became Gulf's successful Energy*Select*® Demand Side Management (DSM) program. This innovative CPP rate has become widely known throughout the electric utility industry. Currently, 17,000 of Gulf's residential customers choose the RSVP rate. The RSVP rate consists of a Base Charge of $0.62 per day and four tiers of Energy Charges—Low, Medium and High which have predetermined rates and time periods and a Critical tier which has a pre-determined rate but may occur anytime during the year under specific conditions.

In 2005, with the approval of the FPSC in Docket No. 040442-EI, Gulf began offering the *FlatBill®* program using the Residential Flat-1 rate. This rate gives customers who choose it the peace of mind that their monthly bill will not change throughout the course of the year. Currently, 14,000 of Gulf's residential customers choose the Residential Flat-1 rate which consists of an annual contract amount specific to each customer billed in twelve equal monthly increments.

In 2016, with the approval of the FPSC in Docket No. 150086-EG, Gulf began offering the RSTOU rate in conjunction with a DSM pilot program named Energy*Smart*. This limited availability experimental rate is limited to approximately 400 subscribers and is currently fully subscribed. The RSTOU rate consists of a Base Charge of $0.62 per day and two tiers of Energy Charges—On-Peak and Off-Peak—each of which have predetermined rates and time periods and a Critical Peak Credit which is a pre-determined amount that may occur anytime during the year under specific conditions.

All of Gulf's residential rates (RS, RSVP, Flat-1, and RSTOU) utilize the same Base Charge (currently $0.62 per day) and the same base rate Energy Charge (currently 4.585 cents per kWh). The time-of-use rate options (RSVP and RSTOU) utilize varying conservation clause factors to create different total energy prices in the time-of-use tiers. Exhibit RLM-1, Schedule 1 contains a summary of Gulf's residential rates.

II. OVERVIEW

Q. Please provide some context for the rate improvements you recommend.

A. The residential market segment is Gulf Power's largest by far. Whether measured in terms of revenue, number of customers, energy, or peak demand, the residential market is the biggest segment of our business. In light of this, it is important to note that the default residential service rate (RS), the rate that over 90 percent of our residential customers choose, has a built-in weakness—it does not recover costs appropriately from cost-causers. Thus, some groups of residential customers are paying more than they should—they are paying more than the costs the Company incurs to serve them. Other residential customers are paying less than they should—they are paying less than the costs the Company incurs to serve them. In the aggregate, we estimate that this inequity is more than $20 million annually.

Q. How do you propose to correct this inequity?

A. Gulf is proposing an Advanced Pricing Package that makes a structural change to improve the equity of our existing two-part residential rates, introduces new residential demand rate options that will also equitably recover costs and will allow customers to select the pricing most beneficial to their individual circumstances, and improves all residential customers' experience with Gulf's product.

Q. How will the structural change to the existing two-part residential rates and the new demand rates more equitably recover costs?

A. The proposed rate structure and new residential demand rates recover demand-related costs more appropriately than current rates. Residential demand-related costs from the cost of service study, as provided by Gulf Witness O'Sheasy, are those costs associated with the generation, transmission and distribution investment and expenses necessary to meet residential customers' peak demand for electricity. In the case of the proposed demand rates, the explicit demand charge appropriately recovers demand-related costs in proportion to the amount of demand a customer places on the system. In the case of the enhanced two-part rate structure, an appropriate amount of demand-related costs are recovered through the fixed component of the rate, the base charge. In both cases, costs are more equitably recovered from cost-causers.

Q. What causes Gulf's current rate structure to inequitably recover costs from residential customers?

A. Gulf's current residential rate structure does a fair job of appropriately recovering customer-related costs through the base charge (also known as a customer charge) and energy-related costs through the energy charge but misses the mark when it comes to appropriately recovering demand-related costs from cost-causers. Under the current rate structure, all residential demand-related costs are collected through the energy charge. This causes the energy charge, the variable component of the customer's rate (cents per kWh charge), to be larger than it should be. This unnecessarily large energy charge, which functions as a weak proxy for a demand charge, causes a misalignment between cost-causers and those who pay. This misaligned structure results in some customers paying more than they should for demand-related costs and others paying less than they should. For example, occupants of older, inefficient manufactured homes or other poorly-insulated homes as a group are paying more than they should while condo owners, small vacation home owners, and owners of private residential metered boat docks as a group are paying less than they should for the demand-related costs incurred to serve them.

Q. How will Gulf's proposed rate structure improve equity in recovery of demand-related costs?

A. Gulf's proposed two-part rates are designed to collect revenue more like optimum three-part demand rates without using explicit demand charges. Details on how this is accomplished are provided later in my testimony but can be summarized as a proper allocation of demand-related costs between the energy charge and the base charge. A simple graphic representation of rate structures and their relationship to costs is shown in Exhibit RLM-1, Schedule 2.

Q. How do the proposed rate structure change and new rates improve customers' experience with Gulf's product?

A. Our customers can experience significant and unnecessary variations in their monthly bills when the variable component of their rate (cents per kWh charge) is larger than it should be. When the weather is particularly hot in the summer or cold in the winter, or when a family entertains or hosts visitors, electricity usage temporarily increases causing fluctuations in a customer's electricity bill. This variability, on a percentage basis, is more acute for low-use customers. A lower energy charge reduces variability in customers' bills. For customers using less than 750 kWh per month, the proposed RS rate reduces bill variability significantly. See Exhibit RLM-1, Schedule 3 for a comparison of customer bill variability.

Q. What about those customers who value the ability to manage their electricity bill through their usage more than stability of their bill?

A. For those customers who do not mind fluctuations in their bill and value more highly the ability to actively manage their bill amount, we are adding new demand rates to our existing menu of options which already includes a rate (RSVP) that gives our residential customers significant flexibility to actively manage their bills through their electricity use.

III. DEMAND RATES

Q. Do three-part demand rates appropriately recover costs from cost-causers?

A. Yes. Mr. O'Sheasy's cost of service study develops three categories of costs associated with serving residential customers: customer-related costs, demand-related costs, and energy-related costs. A three-part demand rate best aligns rates with costs because it mirrors these cost categories with three discrete rate components: a customer charge, a demand charge and an energy charge.

Q. Since demand rates better align rates with costs, why has Gulf not required all residential customers to take service under a demand rate?

A. There are two reasons that demand rates have not been mandatory for residential customers in the past. The first is metering costs—demand meters cost more than simple energy-only meters. The second is limited customer acceptance.

Q. How has Advanced Metering Infrastructure (AMI) affected the first barrier to demand rate implementation in the residential class?

A. The first barrier to implementing demand rates throughout the residential class has historically been metering costs. With the deployment of AMI metering, Gulf Power is no longer constrained by metering costs in implementing demand rates for the residential class. Gulf's existing AMI meters can be reprogrammed at very little cost to measure demand for billing purposes so there is no longer a requirement to purchase new, more sophisticated and more expensive meters to implement a residential class demand rate.

Q. You mentioned limited customer acceptance as a second barrier. Please elaborate.

A. Three-part demand rates are more complex than two-part rates. Demand rates in the residential market introduce a new concept called demand (rate of use rather than quantity of use), another measurement (kW), another rate component ($ per kW), and another line item on the customer's bill. When presented with the choice, most residential customers have not chosen to manage this additional bill element (kW demand) which varies according to coincidence of electrical use. Among the 10 or so investor-owned utilities in the United States that offer optional demand rates to residential customers, participation has been relatively low—averaging less than 3 percent of the total residential customers served by these utilities. However, for the customers that choose this option, they appreciate the value it provides by allowing them to manage their bills through the more complex rate.

Q. What new residential demand rates is Gulf proposing?

A. The first of the two new rates is the Residential Service - Demand (RSD) rate. It is a traditional three-part rate consisting of a Base Charge of $0.73 per day, an Energy Charge of 2.3 cents per kWh (8.7 cents per kWh with proposed cost recovery clause rates) and a monthly Maximum Demand Charge of $5.00 per kW as provided by Gulf Witness Evans.

The second of the two new rates is the Residential Service - Demand Time-of-Use Conservation (RSDT) rate. It is a traditional three-part Time-of-Use (TOU) rate consisting of a Base Charge of $0.73 per day, an Energy Charge of 2.3 cents per kWh (8.7 cents per kWh with proposed cost recovery clause rates), a monthly Maximum Demand Charge of $2.17 per kW and a monthly On-Peak Demand Charge of $3.66 per kW as provided by Mr. Evans. The On-Peak periods coincide with the RSVP High tier periods.

IV. NEW METHODOLOGY FOR SETTING THE RESIDENTIAL BASE CHARGE

Q. Earlier you said some demand-related costs would be collected through the base charge (fixed component of the rate) under your proposed rate structure change. Doesn’t traditional ratemaking dictate that only customer-related costs be included in the base charge?

A. Historically, that is how ratemaking has been done. But there is no prohibition against examining afresh how rates should be structured. If we start with the premise that a mandatory three-part rate is not appropriate for the entire residential class because of limited customer acceptance, we conclude that a simpler two-part rate should be used. But where will we put demand-related costs if we don’t have an explicit demand charge in the rate structure? In the past, all of those demand-related costs have been put into the energy charge—hence its name in our tariff book is actually “Energy-Demand Charge” which is technically correct although cumbersome.

Q. What has been the basis for putting all demand-related costs into the energy charge and none into the fixed base charge?

A. There is a relationship, although a weak one, between energy and demand. In other words, there is a loose connection between how much energy a customer uses and how much demand they create on our system. Customers who use more energy generally have higher kW demands—but there are many exceptions to this general relationship. Load Factor is a term used to describe the relationship between a customer's energy use and their demand. If all residential customers had the same monthly load factor—in other words, if all customers had the same relationship between their energy use and their demand—it would make perfect sense to put all demand-related costs into the energy charge. Under this hypothetical scenario, as a customer used more energy, they would pay for that energy and for the additional demand too. But the fact is that residential customers' monthly load factors vary widely. Exhibit RLM-1, Schedule 4 shows the wide variation in monthly load factors among Gulf Power's residential customers. Some customers use more energy and less demand (these customers are efficient users of utility capacity) and others use little energy and a lot of demand (these customers have "spikes" in their load and are less efficient users).

Q. Since the relationship between energy and demand is weak, what other basis do you propose to determine how to allocate demand-related costs?

A. Gulf proposes to use a methodology developed by Drs. Larry Blank and Doug Gegax (Blank & Gegax methodology or B&G methodology) as an enhancement to the current method for developing two-part rates. The B&G methodology was published in a peer-reviewed article in the April 2016 issue of *The Electricity Journal* and is described in more detail in Exhibit RLM-1, Schedule 5. This enhanced methodology uses objective criteria to determine the best allocation of demand-related costs in a two-part rate. When applied to Gulf's residential customer data, the B&G methodology suggests that approximately half of demand-related costs should be allocated to the energy charge and the other half should be allocated to the base charge.

Q. What is the basis of the B&G methodology?

A. The B&G methodology begins with the premise that a three-part rate appropriately aligns rates and costs. Using a three-part rate as a goal, the B&G methodology identifies a two-part rate that will produce bills which best mimic the bills that would have been produced by the three-part rate. The result is an objective, optimum allocation of demand-related costs between the two parts of the two-part rate—between the base charge and the energy charge.

Q. What rates are you proposing based on the B&G analysis for Gulf's residential customer data?

A. As developed by Mr. Evans, the B&G analysis and revenue requirements for Gulf's residential customers support a $1.58 per day Base Charge (approximately $48 per month) and 3.3 cents per kWh Energy Charge.

Q. So if the new two-part rate structure better aligns rates with costs and collects revenue more like the target three-part rate, why offer demand rates at all?
A. First, demand rates also align rates with costs very well. Secondly, some customers will be pleased with the opportunity to manage their bill in even more detail than in the past. We observe a similar desire in our customers who currently choose CPP and TOU rates.

V. EFFECT OF CHANGE

Q. What effect will Gulf's proposed changes have on customers' bills?
A. The practical outcome of the proposed Advanced Pricing Package is not a "one size fits all" effect. Recovering demand-related costs more equitably through pricing will affect different customers differently. For example, the owner of a vacation condo that is vacant much of the year might see an overall increase as a reflection of the customer paying a more appropriate share of demand-related costs while the occupant of an older, inefficient manufactured home might benefit from the more appropriately priced, lower energy charge. In either case, or in any other of a myriad of examples, the key is that the proposed new rate structure more appropriately allocates costs to the cost-causers.

Q. Is the proposed increase from $0.62 per day to the more equitable $1.58 per day a reasonable amount of change?

A. Yes. In combination with the 28 percent reduction in the energy charge, the change in the base charge is certainly reasonable. The net effect of rate level and rate structure changes on the average residential customer's monthly bill is an increase of about $10, or 7 percent. The majority of this $10 increase is a result of Gulf's requested general increase in base rates as supported by other witnesses in this case, offset somewhat by a proposed decrease in our clause rates for 2017.

Q. Would the proposed Base Charge change if the Commission approved a rate increase other than the one Gulf has requested in this Docket?

A. Yes, but not by much. Under current rates, the B&G methodology would support a Base Charge of about $1.35 per day.

Q. What is the benefit of implementing optional demand rates at the same time that Gulf implements a more equitable base charge in existing rates?

A. The benefit of implementing both changes at the same time is that any customer who does not prefer the higher and more equitable base charge can choose a demand rate option which has a lower base charge—one that only includes customer-related costs. This customer would then be choosing to pay for their demand-related costs through the demand charge. Because the changes are being implemented at the same time, customers will receive appropriate and equitable price signals from either rate type (two-part or three-part). The customer simply chooses which option best suits their needs. A table of example bills is supplied in Exhibit RLM-1, Schedule 6.

VI. LOW INCOME

Q. Is Gulf proposing anything to help low-income customers transition to the more equitable base charge?

A. Yes. Recognizing that a more equitable allocation of demand-related costs in Gulf's two-part residential rates results in a lower energy charge but increases the base charge, Gulf is proposing to accompany its new rate structure with a Low Income Rider, to be known as a Customer Assistance Program (CAP) credit, if approved. The Low Income Rider is appropriate to achieve this objective, but without the change in the residential rate structure the Low Income Rider is simply unnecessary.

Q. Please describe the Low Income Rider.

A. The proposed Low Income Rider will apply a bill credit of $0.69 per day (approximately $21 per month) to eligible customers' monthly bills. The new Low Income Rider is specifically designed to fully offset the incremental increase in the proposed higher base charge for qualifying low-income customers in occupied homes. The calculation showing this result is provided in Exhibit RLM-1, Schedule 7.

Q. What are the eligibility criteria for the new Low Income Rider?

A. Gulf Power's new Low Income Rider will be available to all Gulf Power residential customers of record who are also participants in the Supplemental Nutritional Assistance Program (SNAP), also known as Food Stamps, and who apply for the credit.

Q. How many of Gulf's residential customers do you estimate will qualify?

A. We estimate that approximately 35,000 of Gulf's residential customers will qualify for this credit.

Q. How will the Low Income Rider be funded?

A. Gulf proposes funding the Low Income Rider through the residential class revenue.

Q. Isn't this just a subsidy from the entire group of residential customers to one subset of them?

A. Yes, but it is a transparent and targeted subsidy. The current RS rate structure has embedded in it an untargeted subsidy—an imprecise approach to helping those in need. The current RS rate structure favors all low-use customers regardless of their income. Low-use customers as a group pay less than the costs incurred to serve them. Not all low-use customers are low-income customers (condo owners, small vacation home owners, and owners of private residential metered boat docks, for example) but all low-use customers benefit from the subsidy built into the current rate structure. This untargeted subsidy inadvertently subsidizes non-low-income customers.

High-use customers as a group, on the other hand, pay more than the costs incurred to serve them. Not all high-use customers are high-income customers (some customers whose primary residence is an older, inefficient manufactured home or other poorly-insulated home, for example) but all high-use customers are harmed by the subsidy built into the current rate structure—because they are funding it through the high energy charge.

Gulf is proposing to replace the untargeted subsidy built into the current rate structure with this targeted and explicit subsidy as a better, more efficient way to help those customers who need it most. If the proposed change in the residential rate structure is accepted and approved, the Low Income Rider will accomplish this objective. If the residential rate structure were to remain unchanged, the Low Income Rider would simply be unnecessary.

Q. How would you summarize the purpose of the Low Income Rider?
A. The Low Income Rider, in conjunction with the new rate structure, replaces a subsidy for low-usage customers with a subsidy for low-income customers.

Q. Will the proposed Low Income Rider provide any additional value to Gulf or its customers?
A. Yes, the Low Income Rider will help Gulf better serve a population within its customer base that is otherwise difficult to identify. If the Low Income Rider is implemented, self-identifying qualifying customers may also be able to benefit from other programs offered by Gulf Power and other community organizations that will help them better manage their energy use. For

example, Gulf can reach out to these qualifying low-income customers and proactively offer an energy audit. Furthermore, Gulf can notify low-income customers of other energy assistance programs offered through local agencies such as LIHEAP and Weatherization Assistance Program (WAP). Gulf could also leverage lessons learned from the Community Energy Saver program approved as part of Gulf's 2015 Demand-Side Management Plan to design a new program specifically for these self-identifying low-income customers.

VII. CONSERVATION

Q. Why, in this filing, is Gulf proposing to add additional cost-effective conservation measures?

A. The new residential rate structure lowers the variable charge (cents per kWh) of Gulf's two-part residential rates, thereby improving the Rate Impact Measure (RIM) cost-effectiveness test results for all residential conservation measures. Gulf Witness Floyd discusses this in more detail in his testimony.

Q. What is the effect of the lower variable charge (cents per kWh) on the Participant Test?

A. The lower variable charge reduces Participant Test results slightly. However, the lower variable charge improves RIM test results with so little impact to Participant Test results that the net effect is that more cost-effective conservation is achievable.

Q. Does the new rate structure with its lower energy charge undermine existing and future conservation investment?

A. Not at all. For example, the variable portion of the proposed RS rate, the RS Energy Charge with proposed cost recovery clause rates, would be 9.7 cents per kWh. Although this number is lower than it otherwise would be without the rate structure change, it still provides substantial benefit for customers to manage through investments in conservation.

Q. What additional conservation is Gulf proposing for residential customers?

A. As a result of the residential rate structure change, Mr. Floyd proposes to expand an existing program, to increase the maximum incentives for other existing programs in order to achieve higher energy savings, and to add a new program. Mr. Floyd provides additional information regarding these new and modified residential DSM programs in his testimony.

Q. How much energy savings do these additional conservation efforts represent?

A. These added residential conservation efforts represent an additional 3.5 GWh of average annual savings.

Q. What other conservation benefits does your residential rate proposal have?

A. The two new demand rates will naturally encourage participating customers to manage their peak demand. The new TOU demand rate will also encourage participating customers to shift their peak demand to times when the load on Gulf’s system is not as heavy.

VIII. CONCLUSION

Q. Why should the Commission approve Gulf's proposed Advanced Pricing Package?

A. First, Gulf's proposal includes both a rate structure change (lower energy charge and higher base charge) and the addition of new optional demand rates. These two changes work hand-in-hand to give customers more options and better align our residential rates with our costs. Second, Gulf's proposal applies to all residential customers, not just a sub-segment of them. Third, Gulf's proposal includes a new low-income credit which ensures qualifying customers will benefit from the rate structure change. Fourth, Gulf is proposing to implement additional cost-effective conservation in conjunction with the rate structure change. Fifth, and most significantly, Gulf's proposed rate structure change relies on an objective, best-fit methodology for determining an appropriate allocation of demand-related costs to the base charge.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
John N. Floyd
Docket No. 160186-EI
In Support of Rate Relief
Date of Filing: October 12, 2016

Q. Please state your name and business address.

A. My name is John Floyd and my business address is One Energy Place, Pensacola, Florida 32520.

Q. What is your position?

A. I am employed by Gulf Power Company (Gulf or the Company) as the Energy Efficiency & Renewables Manager.

Q. Please describe your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Auburn University in 1985. After serving four years in the U.S. Air Force, I began my career in the electric utility industry at Gulf Power in 1990 and have held various positions with the Company in Power Generation, Metering, Power Delivery and Marketing. In my present position, I am responsible for the development and implementation of Gulf's customer program offerings including the programs in the Company's Demand-Side Management (DSM) Plan.

Q. What is the purpose of your testimony?

A. My testimony describes two new DSM programs for which the Company is seeking approval. I also propose modifications to existing DSM programs. I describe the details of the programs and explain why these programs are appropriate for approval and in the best interest of Gulf's customers.

Q. Are you sponsoring any exhibits?

A. Yes, I sponsor Exhibit JNF-1, Schedules 1 through 4. This exhibit was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge and belief.

Q. Why is Gulf asking for new DSM programs in this proceeding?

A. As discussed by Gulf Witness McGee, the Company is proposing improvements to our residential rate offerings. One of these improvements is a structural change that involves lowering the Energy Charge and increasing the Base Charge for all of Gulf's existing residential rates. The proposed changes in the residential rate structure allow more cost-effective energy efficiency programs to be offered by the Company. Furthermore, the additional Commercial/Industrial program I propose is supported by simultaneous changes to the base rate offering, Large Power Service Time-of-Use Conservation (LPT).

Q. How does the structural change to residential rates detailed by Mr. McGee affect DSM cost-effectiveness?

A. The lower Energy Charge proposed in the new residential rate structure affects the results of the Rate Impact Measure (RIM) and Participant Test (PT) cost-effectiveness tests which were used to set the DSM goals in Docket No. 130202-EI. With a lower Energy Charge, more measures pass the RIM test and enable the Company to offer more cost-effective DSM programs.

Q. How does the lower Energy Charge in the new rate structure impact the Participant Test result?

A. The lower Energy Charge increases the length of the customer payback period, resulting in a slightly lower PT ratio for measures included in Gulf's DSM Plan. However, the higher RIM scores allow higher incentives to be offered, translating to a higher overall savings for Gulf's DSM Plan. This includes new measures that would be cost-effective due to the rate structure change.

Q. How are DSM goals set for Gulf Power?

A. The Commission sets seasonal peak demand and annual energy conservation goals for Gulf Power every five years for the upcoming ten year period. These goals are based upon costs derived from Gulf's generation, transmission, and distribution planning processes. The goals represent the total cost-effective winter and summer peak MW demand reductions and the annual GWh savings that are reasonably achievable through implementation of demand-side programs in Gulf Power's service area. The basis for the goals is the MW and GWh associated with projected adoption of measures that passed both the RIM and PT.

Q. When were DSM goals last set for Gulf Power?

A. The Company's current goals were established by the Commission in Order No. PSC-14-0696-FOF-EU issued on December 16, 2014.

Q. Please explain how DSM programs are developed to meet the established goals.

A. Pursuant to Rule 25-17.0021(4), F.A.C., Gulf filed a DSM Plan with the Commission on March 16, 2015. The DSM Plan included DSM programs designed to meet the goals approved in Order No. PSC-14-0696-FOF-EU. The Company's DSM Plan was approved as set forth in Order No. PSC-15-0330-PAA-EG.

Q. What DSM programs is the Company proposing to add or modify?

A. Gulf is proposing to add one new residential program, add measures to an existing residential program, and increase the incentive caps on existing residential programs. We are also proposing to add a new commercial program.

I. RESIDENTIAL DSM PROGRAMS

Q. Please describe the new residential program.

A. Gulf is proposing a new ceiling insulation program that is targeted to customers with little or no existing ceiling insulation. Adding ceiling insulation is one of the most cost-effective measures a customer can take to reduce heating and cooling expenses. Although this program will be available to all residential customers, it is Gulf's belief that a majority of customers qualifying for this program will have lower income levels. The program will provide vouchers for, or direct installation of, ceiling insulation as a way of minimizing the out of pocket expense to the customer. A program description along with a set of proposed program standards for this new program is included as Schedule 1 of Exhibit JNF-1.

Q. Please describe the proposed modifications to existing residential programs.

A. Gulf is proposing to modify our HVAC Efficiency program to include heat pump equipment measures. These new measures will complement a number of existing equipment maintenance measures that improve the performance of existing and new HVAC systems, resulting in energy and peak demand savings. The addition of these new measures will also increase the number of HVAC contractors wishing to participate in our current program.

Incentives for similar equipment measures were a part of Gulf Power's HVAC Efficiency program in the 2010 DSM Plan and were well-received by customers and participating contractors. However, these measures were not included in the 2015 DSM Plan due to failing RIM scores during the goal setting process. With the proposed residential rate structure changes, these new measures become cost-effective. A revised program description along with a revised set of proposed program standards for this modified program is included as Schedule 2 of Exhibit JNF-1.

Also as a result of the residential rate structure change, Gulf is proposing to increase the maximum incentives for (a) the reflective roofing measure in the Residential Building Efficiency program, and (b) the HVAC maintenance and duct repair measures in the HVAC Efficiency program. These program modifications should result in Gulf achieving higher energy savings. Revised program descriptions are included as Schedule 2 of Exhibit JNF-1.

Q. How much additional seasonal peak demand and annual energy savings do you expect to achieve with these new and modified residential programs?

A. Gulf expects to achieve savings of 28.1 GWh of energy, 9.7 MW of summer peak demand and 17.0 MW of winter peak demand as a result of these new and modified programs throughout the timeframe of the 2015 DSM Plan. A table depicting these annual savings is included as Schedule 3 of Exhibit JNF-1.

Q. Would these new and modified residential DSM programs be cost-effective if the Commission does not approve the Company's proposed residential rate structure change?

A. No.

II. NEW COMMERCIAL/INDUSTRIAL PROGRAM

Q. Are you also recommending a new Commercial/Industrial DSM program?

A. Yes, I am recommending establishing the existing Critical Peak Option (CPO) available for rate LPT as a DSM program.

Q. Please explain how the CPO rate currently works.

A. The CPO rate option provides qualifying customers an opportunity to realize reduced On-Peak Demand Charges in conjunction with a higher Critical Peak Demand Charge. As explained by Gulf Witness Evans, the option introduces a third demand charge for customers on the LPT rate. This third tier demand charge is in addition to the Maximum Demand Charge, On-Peak Demand Charge, Energy Charge and Base Charge rate components found in these rates. The demand charge applicable to that critical peak period is higher than the On-Peak Demand Charge, but customers with load management abilities avoid, or substantially reduce, their demand during these short periods, resulting in bill savings to the customer and reduced peak demand requirements on Gulf's grid.

Q. Please describe how this new DSM program changes the current CPO.

A. As part of this program, qualifying commercial and industrial customers will choose the CPO option in the same way they do currently. This change replaces the reduced On-Peak Demand Charge with a capacity credit. Customers participating in this program will receive the On-Peak Capacity credit for measured demand during the on-peak period and will be subject to the Critical Peak Demand Charge for all measured demand during the critical period. Credits provided during on-peak periods and revenues collected during critical peak periods will be accounted for in the Energy Conservation Cost Recovery (ECCR) clause. Also, Gulf proposes to reduce the minimum notice provision to one hour and to eliminate restrictions on the frequency and duration of critical peak periods.

Q. Why is Gulf proposing to reduce the minimum notification for a critical peak event to one hour?

A. First, reducing the minimum notice provision will enable Gulf to utilize the CPO program in a manner which is more consistent with its objective—to provide demand reduction during peak load conditions. The current minimum of one business day's notice requires Gulf to project system peak loading conditions one or more days ahead of time. In some circumstances, this may result in Gulf unnecessarily scheduling a critical event when expected peak conditions do not materialize. Conversely, it may result in Gulf not being able to utilize this capacity when peaking or otherwise critical loading conditions develop quickly. This change also more closely aligns this program with Gulf's residential critical peak programs RSVP and RSTOU, both of which contain thirty minute minimum notice provisions.

Q. Why is Gulf proposing to eliminate restrictions on the frequency and duration of critical peak periods?

A. Under the current CPO, critical peak periods are limited to one to two hours in duration and a total of 87 hours in a calendar year. The total number of critical peak periods may not exceed one per day and four per week. As I discuss later in my testimony, Gulf's proposal to address On-Peak Capacity credits and Critical Peak Demand Charges through the ECCR will ensure that the program remains cost-effective (i.e., passes the RIM test) and is, therefore, beneficial for Gulf's general body of customers. Because the program will remain cost-effective, Gulf believes it is appropriate to eliminate restrictions which could otherwise impair Gulf's implementation of the program for the full benefit of its general body of customers.

Q. How is the On-Peak Capacity credit determined?

A. The On-Peak Capacity credit is determined based on the value of avoided capacity during a critical peak period. For 2017, this value is $4.75 per kW.

Q. How is the Critical Peak Demand Charge determined?

A. The Critical Peak Demand Charge is set at an amount to encourage maximum demand reduction during a critical peak event as well as to ensure the benefits of the On-Peak Capacity credits are realized to Gulf's customer base. For 2017, the Critical Peak Demand Charge is $57.00 per kW.

Q. Why is Gulf proposing these changes to CPO?

A. The CPO offering was first made available for Gulf Power customers in 2012. Over this period of time, Gulf has gained experience with the offering and determined that repurposing the offering as a DSM program and addressing the variability in the time differentiated rates through ECCR is appropriate and beneficial for Gulf's general body of customers. The CPO's primary function is to provide peak demand savings. Therefore, it fits naturally in Gulf's suite of DSM offerings which also serve to reduce peak demand and energy consumption. Also, the value of capacity resources fluctuates from time to time based on the timing and type of Gulf's resource needs. Presently, the benefit provided to participating customers in the form of a reduced On- Peak Demand Charge is embedded in Gulf's base rates and is not cost-effective based on Gulf's current planning assumptions. Inclusion of the CPO as a DSM program provides for annual opportunities through the ECCR process to adjust the On-Peak Demand Charge (using a capacity credit) and the Critical Peak Demand Charge to ensure the rate option remains cost-effective for all of Gulf's customers.

Q. Is there any precedent for shifting base rate pricing components to ECCR?

A. Yes. This Commission has previously approved moving variable components of rates from base revenues to cost recovery clause revenues in Orders No. PSC-12-0179-FOF-EI issued April 3, 2012 and PSC-13-0670-S-EI issued December 19, 2013. In Order No. PSC-12-0179-FOF-EI, the Commission approved moving the variable components of Gulf's Residential Variable Service Pricing (RSVP) associated with Gulf's Energy Select program into ECCR. In this order, the Commission recognized that this pricing variability was a part of the approved DSM program and approved recovery as such. In Order No. PSC-13-0670-S-EI the Commission approved a stipulation that included moving the variability in Gulf's Real Time Pricing (RTP) rate schedule into the fuel cost recovery clause (FCR). In that proceeding, Gulf noted that the variability in the RTP prices was represented by fuel cost differences and accordingly proposed recovery of that variability in FCR.

Q. Is there precedent for recovering capacity credits in the ECCR expenses?

A. Yes. Tampa Electric Company, Duke Energy Florida, and Florida Power & Light all recover capacity payments for similar, though not identical, programs through the ECCR mechanism.

Q. Is this program cost-effective?

A. Yes. The value of the capacity credits is determined through the DSM cost-effectiveness process in the same way that all other programs or measures are evaluated. This process establishes the value of avoiding, or deferring, capacity additions. The RIM test is the basis for the On-Peak Capacity credit, ensuring that all customers benefit regardless of whether they elect, or are even eligible, for this rate option. The Critical Peak Demand Charge ensures that customers electing this rate option have an economic incentive to respond to critical peak events when they are called. If participating customers respond, capacity savings are realized for the general body of customers. Alternatively, if participating customers do not respond, they must pay the Critical Peak Demand Charge and the associated revenues are returned to the general body of customers through the ECCR process. A program description for the CPO program, along with the related cost-effectiveness results, is attached as Schedule 4 of Exhibit JNF-1.

Q. How many customers do you project will participate in the CPO program?

A. At this time Gulf is projecting that the 21 customers currently electing service under the CPO option would remain on this program. Gulf is not projecting any additional customers will subscribe initially.

III. SUMMARY

Q. Would you please summarize your testimony?

A. Gulf is proposing expansion of the Company's DSM Plan as a result of improved cost effectiveness resulting from the proposed structural change to the Company's residential rates. In addition, Gulf is proposing to move cost recovery for the On-Peak Demand Credit and Critical Peak Demand Charge associated with CPO to the ECCR mechanism.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael T. O'Sheasy
Docket No. 160186-EI
In Support of Rate Relief
Date of Filing: October 12, 2016

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

A. My name is Mike O'Sheasy. My business address is 5001 Kingswood Drive, Roswell, Georgia 30075. I am a Vice President with Christensen Associates, Inc.

Q. State briefly your education background and experience.

A. I received a Bachelor’s of Industrial Engineering from the Georgia Institute of Technology in 1970. In 1974, I earned a Master’s in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company—a Division of the Carnation Company—as a plant superintendent in their Chamblee, Georgia operation. From 1975 to 1980, I worked for the John Harland Corporation, initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida plant, and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions to the position of supervisor, during which time I began serving as an expert witness in costing. I testified as Gulf Power Company's (Gulf or the Company) cost-of-service witness and provided other support to Gulf in matters before the Florida Public Service Commission (FPSC or the Commission).

In 1990, I became Manager of Product Design for Georgia Power Company and have testified before the Georgia Public Service Commission as an expert witness on rate design and pricing. I retired from Georgia Power Company on May 1, 2001 and became a consultant with Christensen Associates.

Q. Please identify the specific dockets in which you have previously testified before the FPSC.

A. I testified before the FPSC on behalf of Gulf as their cost-of-service witness in the 2012 test year rate case, Docket No. 130140-EI, and in Docket Nos. 110138-E1, 010949-EI, 891345-EI and 881167-EI. I was extensively involved in the preparation of exhibits and Minimum Filing Requirements (MFRs) in those cases. Also, I was the back-up cost-of-service witness for Gulf in its 1984 rate case, Docket No. 840086-EI, where I helped prepare the related analyses. I also testified in Docket No. 850673-EU regarding standby back-up electric service.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the development and results of the cost-of-service study for Gulf.

Q. Are there any material differences in your testimony here and in Gulf’s two prior rate cases?

A. No, and there are not material differences in how the studies were conducted. The cost of service studies presented in this filing are very similar to the previous cases. We believed then and remain convinced that these methodologies for cost allocation and assignment are the best reflection of cost causation for Gulf Power's customers.

Q. Do you have any exhibits that contain information to which you will refer in your testimony?

A. Yes. My Exhibit MTO-1 (consisting of Schedules 1 through 3) and Exhibit MTO-2 (containing Schedules 1 through 6) were prepared under my supervision and direction by the Costing and Energy Analysis Team of Southern Company Services (SCS), which is the service company in the Southern electric system (SES), and the Costing and Load Research Engineer at Gulf. SCS provides engineering and other technical support for Gulf and the other SES operating companies. I have thoroughly reviewed the schedules in my exhibits and agree with their content.

Q. Are you the sponsor of certain MFRs?

A. Yes. The MFRs which I am sponsoring, in part or in whole, are listed on Schedule 1 of Exhibit MTO-1. To the best of my knowledge, the information contained in these MFRs is true and correct.

Q. Please describe the contents of your Exhibit MTO-2.

A. My Exhibit MTO-2 consists of a number of schedules that set forth the analyses and results of the cost-of-service study used as a basis for this case. Page 1 of MTO-2 provides an index to the Schedules contained in my exhibit. Each schedule was prepared in the manner approved by the

Commission in its final order for Gulf's 2012 test year rate case, Docket No. 110138-EI. That approved methodology was continued in the approved settlement of Gulf's 2014 test year rate case.

I. COST-OF-SERVICE METHODOLOGY

Q. What is a cost-of-service study?

A. A cost-of-service study is a tool used to separate a utility's total electric investments, revenues and expenses first among the regulatory jurisdictions which an electric utility serves (jurisdictional separation) and then among the rate classes within each jurisdiction.

Q. Why is a cost-of-service study necessary?

A. Gulf is regulated by the FPSC for retail sales and by the Federal Energy Regulatory Commission (FERC) for wholesale sales. Costs and revenues must be divided between the two jurisdictions using assignments and allocations so that each respective commission can evaluate the rates over which it has authority. In order for each regulatory commission to review the utility's earnings and to evaluate the contribution made by rate classes within its jurisdiction, it is also necessary to analyze the costs to serve the respective rate classes.

Gulf, like other electric utilities, maintains its books and records in accordance with the Uniform System of Accounts as directed by the FERC and this Commission. Although this system of accounting reveals company-wide information, it does not separate the Company's investments, revenues and expenses by jurisdiction or by rate classes within jurisdiction. The cost-of-service study that has been performed for Gulf accomplishes this objective.

Q. What is the goal of a cost-of-service study?

A. The goal of a cost-of-service study is to identify what costs are incurred to provide service to a specific jurisdiction and to certain groups of customers within that jurisdiction. If it is performed well, it can be a useful (and often times the primary) tool for determining the adequacy of current rates. For those rate classes which the cost-of-service study reveals have inadequate returns at current rate levels, the cost-of-service study is an appropriate tool for helping determine what rate changes should be made. On the other hand, if a cost-of-service study is not performed well, erroneous conclusions can be drawn with resulting negative consequences if it influences subsequent rate design. Although there are other ways to allocate costs, the Company's proposed methodology is objective, consistent with the methodology used in numerous previous rate cases, and provides the most accurate information.

Q. If a use of a cost-of-service study is to assist with ratemaking and the adequacy of rates, should results from the study be used to help guide rate design?

A. Yes. The cost-of-service study will reveal the rate classes' revenue requirements and the unit costs for use in the design of each of the rates. By adhering as close as feasible to these costs, subsidies can be minimized and efficient price signals will be sent.

Q. How did Gulf use your cost-of-service study in this retail rate filing?

A. The jurisdictional separations of rate base and net operating income resulting from the study were used by Gulf Witness Ritenour to determine the proposed jurisdictional revenue increase needed in order to achieve the requested rate of return. These jurisdictional separation factors were calculated according to accepted cost-of-service principles and followed the methodology accepted by the Commission in Gulf's previous filing, Docket No. 130140-EI, and other Gulf filings. The retail jurisdiction was further divided into the respective rate classes using sound cost-causative methodologies. The resultant rate class information from the cost-of-service study was then considered by Gulf Witness Evans as a basis for the design of proposed rates in this docket.

Q. In preparing a cost-of-service study, is there some overall guiding principle or concept that should be followed?

A. Yes. The overall objective of a cost-of-service study is to assign or allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting cost-of-service study reflects "cost causation," i.e., those customers who caused a particular cost to be incurred by the Company in providing them service should be responsible for that cost.

When certain costs are readily identified with a particular customer group (rate class), the assignment of those costs to that group clearly reflects cost causation and is fair and equitable to all customers. However, most parts of an electric system are planned, designed, constructed, operated and maintained to serve all customers. Most of Gulf's costs have been incurred to serve all customers. These costs are referred to as joint or common costs. Joint or common costs must be allocated to customer groups based on the nature (i.e., drivers) of the costs incurred and the aggregate requirements and service characteristics of the customers that caused the costs to be incurred. By adhering to this fundamental and essential principle of cost causation, the results of the cost-of-service study will be fair and equitable to all customers.

Q. How is a cost-of-service analysis performed?

A. In order to determine the costs to serve each group of customers in a fair and equitable manner, the utility company's records are analyzed to determine how each group of customers influenced the actual incurrence of costs by the utility. This review discloses certain direct costs that should be assigned to the specific rate class for which these costs were directly incurred. This review also discloses costs which are incurred to perform a function within the electric system for multiple customer rate classes, referred to as common costs. These common costs are then allocated among those rate classes using an allocator that appropriately reflects the underlying cost causative relationship(s).

Q. Please elaborate on the distinctions between various types of direct and allocated costs.

A. Certain costs are directly associated with one particular group of customers and are, therefore, directly assigned to that group. An example is FERC Account 373 – Street Lighting. All costs associated with this account will be assigned to the street lighting rate class OS.

The majority of costs, however, are incurred jointly to serve numerous customer rate classes. An example of common costs is FERC Account 312 – Boiler Plant Equipment, which serves all rate classes. In order to allocate the various common costs like Account 312 to the rate classes, consideration must be given to the type and classes of customers, their load characteristics, their number, and various other expense and investment relationships in order to find the cost causative link.

Research of cost causative relationships reveals that costs normally possess one or more of three attributes that identify the driving linkage between customer and company. This cost categorization or componentization can be viewed as: (1) <u>customer-related</u>, which are costs that vary with the number of customers or the fact that customers must be able to receive service; (2) <u>energy-related</u>, which pertain to costs that vary with energy consumption (kWh); and (3) <u>demand-related</u>, which are costs that are incurred to serve peak needs for electricity (kW). Each of these three "drivers" has its own separate and appropriate allocators to spread its respective costs to the associated rate class and jurisdiction.

Once the various common accounts have been analyzed to identify their appropriate cost component(s), the corresponding allocator(s) can be applied to apportion common costs to the area of responsibility. By summing the allocated common costs and the assigned direct costs by jurisdiction and rate class, the rate of return for each group can be determined. If conducted upon a sound basis of cost causation, the cost-of-service study can be the benchmark to determine the adequacy of current rates and how well rate groups are covering their costs.

Q. Please expand on the importance of accurate cost allocation.

A. The goal of a cost-of-service study is to identify what costs are incurred to provide service to certain groups of customers. It is based upon the principle of cost causation. As stated in the National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual*, "The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class" (pg. 13).

Q. Please give an example of the consequences of proper and improper allocations in a cost-of-service study.

A. In general, a meter is necessary to measure the amount of electricity provided to a customer, but the meter can operate adequately regardless of the maximum demand or the overall quantity of energy consumed. The cost of the meter incurred by the utility to serve the customer does not vary with demand or the quantity of energy consumed by the customer; it is driven by the fact that each customer needs a meter. As a result, utilities will usually consider meters to be customer-related, and allocate meter costs to the various rate classes using an allocator which reflects the number of customers in each rate class.

If meters were misclassified as kWh (energy) related, then the corresponding kWh allocator would spread more meter costs to large customers and less meter costs to small customers despite the fact that the large customers and the small customers both required the same meter and imposed the same costs on the utility. The large customers' overall cost responsibility would be ultimately overstated and that of the smaller customers would be understated.

II. GULF'S COST-OF-SERVICE STUDY

Q. Please explain Schedule 1 of your Exhibit MTO-2.

A. Schedule 1.00, pages 2-3, of Exhibit MTO-2 is the result of the cost-of-service study in summary form for the test year utilizing the Company's present rates. It shows the Company's total rate base, revenues, expenses, and net operating income, along with the corresponding responsibilities of the retail jurisdiction, as well as the rate classes within the retail jurisdiction. The column denoted "Wholesale" represents full requirements wholesale, which is under the jurisdiction of the FERC. The column denoted "Unit Power Sales (UPS)" reflects the portion of Gulf's ownership interest in Plant

Scherer that is temporarily committed to an off-system sale to another electric utility.

Schedule 1.01, pages 4-5, is similar to Schedule 1.00 except that it shows revenues by rate class that would produce equal rates of return by rate class at the present retail rate of return. Schedule 1.10, pages 6-7, is similar to Schedule 1.00 except that it is based upon the Company's proposed revenues and related expenses by rate class. Schedule 1.11, pages 8-9, states what would be the revenues and related expenses that enable each rate class to achieve the same rate of return as will the retail jurisdiction under the Company's total retail proposed revenues and related expenses.

Q. What are the rate classes in the retail jurisdictional cost-of-service study for Gulf?

A. The rate classes in Gulf's retail jurisdictional cost-of-service study are:

- Rate Class Residential
- Rate Class GS (Small Business)
- Rate Class GSD/GSDT (Medium Business)
- Rate Class LP/LPT (Large Business)
- Rate Class Major Accounts (Very Large Business)
- Rate Class Outdoor Service (OS)

Q. What is the purpose of Schedule 2 of Exhibit MTO-2?

A. Schedule 2 of Exhibit MTO-2 analyzes investment related accounts and either assigns or allocates them to the appropriate jurisdiction and then to rate classes within the retail jurisdiction. It includes Gross Plant Schedule 2.10, pages 10-14, Accumulated Depreciation Reserve Schedule 2.20, pages 15-17, Materials and Supplies Schedule 2.30, pages 18-19, Other Working Capital Schedule 2.40, pages 20-24, and Other Rate Base Items Schedule 2.50, pages 25-27. Together these schedules flow to the summary Schedule 1 to provide rate base by jurisdiction and rate class.

Q. What is shown on the remaining schedules of Exhibit MTO-2?

A. Schedule 3.00, pages 28-29, provides the Analysis of Revenues. Schedule 4 displays the Analysis of Expenses. Schedule 4.10, pages 30-41, details the allocation of Operations and Maintenance (O&M) expenses to jurisdiction and rate classes. Schedule 4.20, pages 42-44, describes the Depreciation expense allocation, and Schedule 4.30, pages 45-47, presents the Analysis of Taxes Other Than Income Taxes. Schedule 5.0, pages 48-50, contains the Table of Line Allocators and Percentages. The results of these various schedules are summarized in Schedule 1. Schedule 6 shows the development of the Minimum Distribution System.

Q. Please identify the steps that were undertaken in preparing the cost-of-service study shown in your Exhibit MTO-2.

A. The development began with the collection and analysis of load research data. This research provided the number of customers and their respective demand and energy sales by voltage level of service which were then used to produce the allocators.

The load research data for the test year was supplied by Mr. Evans. He also provided monthly coincident peak (MCP) demands and annual non-coincident peak (NCP) demands by rate class and voltage level. Gulf Witness Park provided annual energy sales and the average number of customers for the test year by rate class along with total territorial supply and losses for annual energy and system peak demand. These inputs were then used to calculate the "12-MCP," “NCP,” "energy," and "number of customers" allocators.

Q. Please describe the 12-MCP and NCP concepts and why they are used.

A. The 12-MCP demand is the sum of the highest kilowatt load predicted to occur in each month of the test year divided by twelve. This 12-MCP concept recognizes the fact that Gulf's system is planned and operated for the purpose of meeting these demands for electricity every month of the year. It also reflects consideration of scheduled maintenance, firm sales and purchase commitments, and reliance on interconnections. In addition, 12-MCP has traditionally been the FERC's preferred allocation technique for determining the wholesale jurisdictional obligation. The 12-MCP demand allocator has been used to help make the split between retail and wholesale. Within the retail jurisdiction it is used to allocate generation level demand-related costs and costs for transmission step-up substations, transmission lines, and substations linking transmission with distribution.

The NCP demand for each retail rate class is the highest demand occurring for that rate class during the test year. The NCP demand allocator was used to allocate distribution demand costs at Level 4 (primary distribution) and Level 5 (secondary distribution) and was similarly applied in Gulf's 2014 test year rate case.

Q. Please explain the steps that were used in developing the demand and energy allocators.

A. Balanced system load flows for demand and energy were first developed through a load flow program, which spreads total system losses to each voltage level. These levels, which are defined in more detail in MFR E-10, are used to describe the flow of electricity from generation, through the various transformations, across the various transmission and distribution lines, to the eventual delivery to the customer.

The load flow process begins by taking the total energy sales at Level 5, the secondary distribution level, multiplying these sales by the loss percentage at Level 5, and then combining these calculated losses and sales. This amount is then added to the sales at Level 4, and this new total is, in turn, multiplied by the loss percentage at Level 4. This procedure is continued up through Level 1, the generation level. The program adjusts the loss percentages at each level and then iterates the above process until the sum of the losses at each level matches the total system losses and a balanced flow is produced. These total system loss percentages are then applied to the rate classes by voltage level, thus computing energy allocators for each respective voltage level. A similar process is used to calculate the 12-MCP demand allocators. The NCP demand allocators for Levels 4 and 5 are developed similarly and use the loss percentages calculated by the 12-MCP demand flow, since there is no territorial input for NCP with which to balance.

Q. What other types of allocators were used besides demand and energy?

A. Customer-related allocators were also used in order to allocate customer-related costs.

Q. What was the next step in the development of Gulf's cost-of-service study?

A. Ms. Ritenour provided the financial information for the projected test year. These investment, revenue, and expense items were then assigned to jurisdiction and rate class if a direct cost causative relationship was known, or allocated to jurisdiction and rate class using the previously developed allocators.

Q. How were the allocations made between the wholesale and retail jurisdictions?

A. Where costs were identified as serving only the retail or wholesale jurisdictions, they were assigned to that respective jurisdiction. Where costs were common and served both jurisdictions, they were allocated. The jurisdictional separation for demand costs was based upon the 12-MCP allocation. A kWh allocator was employed for the allocation of energy-related costs. Again, this methodology is consistent with the one approved in Gulf's 2014 test year rate case. The methodology also conforms to MFR E-1.

Q. Please describe the analysis within the retail jurisdiction.

A. Where known to serve a particular rate class, revenues and costs were directly assigned. For example, residential revenues were assigned to the residential rate class and outdoor lighting fixture costs were assigned to the outdoor service rate class. The majority of costs were common and therefore allocated. Generation level costs were allocated on the basis of 12-MCP & 1/13 kWh (energy). Energy-related accounts were allocated upon the kWh allocator. Transmission, subtransmission and substations were allocated upon the12-MCP concept. Primary and secondary distribution demand-related costs were apportioned on the corresponding NCP allocators, and customer-related costs were allocated upon the respective customer allocator.

III. COST-OF-SERVICE METHODOLOGY COMPARED TO LAST GULF FILING

Q. How does the cost-of-service methodology proposed by Gulf in this case compare to the methodology approved in Gulf's last retail base rate proceeding?

A. It is the same fundamental methodology filed and approved by stipulation in the Company's last rate proceeding. The study uses 12-MCP & 1/13 kWh for allocation of generation capital cost, 12-MCP for allocation of transmission and substations costs, non-coincident peak demand for allocation of distribution cost, and the Minimum Distribution System (MDS) for separating distribution cost into demand and customer components.

Q. Are you providing any additional cost of service studies in this case?

A. Yes, there is one other study which is identical to the proposed study previously described except it excludes use of MDS in order to comply with an MFR. This study can be found in MFR E-1.

Q. Please describe the Minimum Distribution System methodology and why Gulf believes it is important.

A. As I discuss in more detail later, some inherent, intrinsic costs of the distribution system besides the customer meter and service drop do not vary with customers' use of electricity. These costs are necessary simply for a customer to be "hooked-up" and able to receive service. The Minimum Distribution System (MDS) methodology is necessary to accurately determine and subsequently allocate these customer-related distribution costs.

Q. Where are customer-related costs found?

A. Basically, they can be found in Customer Assistance, Customer Service and the FERC mass distribution accounts. They relate to the costs of being capable of providing electric service. In other words, regardless of the quantity of electricity demanded, the mere fact that the utility must be prepared to provide service at any time causes those costs to be incurred. These customer-related costs are driven by the simple fact that each customer must have the ability to receive service.

This cost category, which Gulf designates as “customer-related,” includes those distribution costs that do not vary with demand use. Some may vary directly with the number of customers to be served, while others are a fixed requirement necessary for a distribution system regardless of usage. An example would be protective devices (found in FERC Account 368), which operate in the same manner with or without load on the system in order to keep the lines available to as many customers as possible.

Q. Which FERC accounts require cost classification scrutiny to identify their customer-related component?

A. Accounts 364-370 usually require an analysis to properly apportion their overall costs into those which are customer-related and those which are demand-related.

Q. What harm can occur if these accounts are not classified properly into customer-related and demand-related using MDS?

A. The misclassification of costs that results from not using the MDS methodology could lead to inaccurate price signals to customers. This misclassification also results in different customer rate classes bearing more or less cost than their cost-causative share of distribution costs. It is therefore important to examine these customer-related costs and classify them appropriately, which the MDS methodology enables us to do.

Q. Does NARUC advocate accurate cost classification and the allocation of these accounts?

A. Yes. Its official guidebook, the *Electric Utility Cost Allocation Manual,* offers clear instructions. The following is an excerpt from page 90 of its January 1992 edition:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities.

They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept costs, as applicable) of facilities.

Q. Does the NARUC manual require that the cost-of-service study be done in a certain manner?

A. No, the NARUC manual is a guide that offers reasonable and logical methodologies for cost allocation. The manual discusses only the major costing methodologies and acknowledges those that are acceptable.

Q. Can you expand on the logic of a customer-related component for distribution accounts?

A. Yes. Schedule 2 of Exhibit MTO-1 depicts a simple distribution network. Now, imagine three different usage scenarios of this network:

Scenario I: Imagine that houses A-E are expected to all have about the same load usage. Now imagine that houses A and B become unoccupied due to impacts of a downturn in the economy or a rental or vacation home now experiencing high vacancy rates. The result is that load on the system goes down, yet the cost of the distribution network remains the same.

Scenario II: Now imagine that all 5 houses are occupied with like load usage. Next, houses C & D employ energy efficiency improvements. Load on the system diminishes, yet the cost of the distribution network remains the same.

Scenario III: Next imagine that all 5 houses are occupied with like load usage. Now imagine that houses C, D, & E add energy efficiency improvements, but a new house F is added to the network with a load equal to what the energy efficiency improvements were for houses C, D, & E. The result is that the total load on the system remains the same, yet the cost of the distribution network must be expanded for new poles and lines.

In each scenario, one can see that the cost of the distribution network is influenced by the number of customers served, not by any changes in total demand or energy usage. Therefore allocating these customer-related costs on a basis other than a customer allocator would result in an inaccurate cost classification and allocation. Assuming that an underage in properly defining customer cost is absorbed in demand cost, this inaccurate classification could lead to a demand or energy charge that is larger than its true cost. The customer receives a resultant price signal that is larger than it should be.

Even if rate designs do not exactly follow cost of service, it is crucial to have a cost-causative cost-of-service study. It is important that both rate designers and policy makers have an accurate cost benchmark so that deviations from true costs can be observed and considered. Otherwise, rate decisions will be based on inaccurate information about true cost responsibility and impacts.

IV. HOW THE MINIMUM DISTRIBUTION SYSTEM METHODOLOGY IS PERFORMED

Q. How do you determine the customer-related costs of distribution?

A. The process of identifying customer-related costs uses the concept mentioned in the NARUC manual called the Minimum Distribution System. (MDS). This concept is based on the fact that in order to simply connect a customer to the power system, a minimum amount of facilities and equipment are necessary. The minimum distribution facilities, along with meters and service drops, make up the plant investment portion of customer-related costs. The distribution facilities in excess of the minimum are classified as demand-related costs because they relate to capacity.

Q. How does one determine this minimum amount of facilities and equipment to simply enable service?

A. There are two common ways to conduct such an analysis: (1) minimum size (MS) and (2) zero-intercept (ZI). The philosophy of MS is that in order to simply connect a customer to the system, a minimum size/amount of equipment is necessary. The cost of this minimum equipment is then categorized as a customer-related cost. For example, suppose that a 15 kVA line transformer represents the smallest size transformer normally used. In this case the unit installed costs of a 15 kVA transformer would be employed as the basis for the customer cost of transformers, with the residual transformer costs treated as demand-related. This analysis, although logical, has a weakness because even the smallest standard size equipment such as the 15 kVA transformer is capable of carrying load, i.e., it has capacity. This capacity is demand-related and should therefore be embedded within another price component. The second analysis procedure, Zero-Intercept (ZI) is an improved technique for determining customer-related costs that, by definition, removes any ability of carrying load. Gulf employed the ZI analysis procedure.

Mr. Lawrence J. Vogt in his published treatise, *Electricity Pricing: Engineering Principles and Methodologies* (2009) identified the zero-intercept and minimum system analysis. Mr. Vogt writes as follows:

> The concept of a minimum distribution system recognizes that the primary and secondary distribution system has both customer-related and demand-related attributes. As discussed previously, the customer cost component is associated with no-load conditions, whereas the demand cost component is associated with load conditions.…
>
> When a single device has both customer-related and demand-related attributes, its total cost must be allocated. The minimum intercept or zero-intercept methodology provides a rational basis for separating the cost of a device between its customer and demand components. (Id. at pp. 498-500.)

Q. How is the Zero-Intercept analysis conducted?

A. ZI is based on a regression analysis of equipment costs. The y-axis is based upon equipment unit cost, and the x-axis is based upon load carrying capability considering sizes of equipment. This analysis creates a regression equation with acceptable confidence intervals that provides cost projections for equipment having load capacities outside the range of existing equipment. This allows a cost analyst to extrapolate back to a level of zero (i.e., no-load) capacity referred to as the y-intercept. The equation thereby identifies a value of unit cost for equipment with zero load capacity. This avoids any double counting of load with MDS. The ZI analysis can be observed in Schedules 6.1, 6.2, and 6.3 of Exhibit MTO-2.

Q. When using different sizes of equipment in the ZI regression, did you employ all sizes in use by Gulf?

A. No, we used the equipment which Gulf now purchases and anticipates continuing to purchase and avoided use of antiquated equipment sizes. For example, to use 7.5 kVA or 10 kVA transformers in the analysis would produce misleading results since Gulf has no plans to continue use of small transformers like these.

Q. If the unit cost is based upon a concept of equipment with no-load capability, do you consider the MDS to be an unrealistic or fictional concept as has sometimes been claimed?

A. No. MDS is no more of a fictional concept than is a deposit requirement for a vacation rental on Pensacola Beach or a simple retainer fee. A deposit is required to preserve the ability to occupy the rental space for future use. Likewise, the retainer fee is required to secure the right of future service regardless of the magnitude of additional services to be rendered. Similarly, the MDS is the cost required to ensure the availability of service to a customer premise whether or not any electricity is ever actually consumed.

Q. Is any equipment built to zero load specifications?

A. No, there is none to my knowledge. Likewise, there is no generating plant that is built with exactly 1/13 of its capital cost to minimize fuel cost as required by one of the MFRs for allocation of production costs. This does not mean, though, that ZI is an illogical concept and therefore not to be used. Even though no equipment is built to serve zero load, the ZI concept is still a valid method of identifying customer-related cost, because ZI recognizes the intrinsic cost of providing service – the necessary elements to merely enable service to be provided.

Q. What FERC mass distribution accounts are split and classified to customer and demand in this manner?

A. Distribution Accounts 364, 365, 366, 367, and 368 use ZI analysis.

Q. Please explain further how these splits are then used in the cost of service study for allocation to rate classes.

A. The resultant split will divide each respective FERC account into a customer-related piece and a demand-related portion. An appropriate customer-related allocator will next allocate the customer portion to the rate classes, and similarly an appropriate demand allocator will allocate the demand portion to the rate classes.

Accounts 369 and 370 are considered as all customer-related. Any related expense accounts (for example depreciation expense) then utilize the corresponding 364-368 accounts to appropriately split expenses into customer and demand-related costs. The computation of the splits for Accounts 364-370 are shown in Schedules 6.4 to 6.10 of Exhibit MTO-2.

Q. Are Account 369 (Service Drops) and Account 370 (Meters) usually classified as 100 percent customer-related?

A. Yes, this has been the traditional treatment for most utilities. Service Drops are the lines that provide the service connection between the secondary level distribution transformer and the customer's meter and enable the customer to receive service. The meter, as previously mentioned, measures the amount of electricity that the customer consumes and is used for billing.

Q. What are the resultant customer/demand splits that Gulf is proposing?

A. The customer-related analysis performed for Gulf results in the customer/demand splits shown on Schedule 3 of Exhibit MTO-1. These are the splits which Gulf is proposing for its recommended cost of service study.

Q. Do any other electric utilities use MDS to determine the customer-related costs?

A. Yes. In fact, all the other regulated operating companies in the Southern electric system use MDS to determine the customer-related costs. Examples of other utilities that employ MDS include Kentucky Utilities, Dayton Power and Light, Manitoba Hydro, LG&E, Nova Scotia Power, Tennessee Valley Authority (TVA), Wisconsin Public Service, and Virginia Electric Power.

Q. Has Gulf's use of MDS previously been approved by the Commission?

A. Yes. The Commission approved Gulf's use of MDS in the final order in Gulf's 2012 test year rate case. The MDS methodology was continued in Gulf's 2014 test year rate case, and it expressly formed the basis for setting the rates included in the Commission-approved stipulation.

Q. Was there any discussion of the MDS methodology during the Commission's consideration of the stipulation offered in Gulf's 2014 test year rate case?

A. Yes. During the December 3, 2013, Commission Conference, Commission Staff was asked for comment on Gulf's use of the MDS methodology. Staff stated: "Staff has generally moved in the direction of believing MDS is an appropriate new cost-of-service technique, if you will, and so recommended in the TECO case." [Commission Conference Transcript p. 55]

Q. Prior to approving the stipulations to use MDS in Gulf's last two base rate proceedings, has this Commission ever approved MDS?

A. Yes, it was approved for Choctawhatchee Electric Cooperative Inc. (CHELCO) in Docket No. 020537-EC.

Q. Will the use of MDS allocate a disproportionate share of cost to the residential and small commercial rate classes?

A. No. Using MDS and including the resultant customer component in the distribution accounts, as opposed to not using MDS, will result in allocating more costs to the residential rate class and small commercial rate class, and usually it will result in allocating less costs to large business classes. However, this is appropriate, since it better reflects the cost to serve these rate classes. It is not "disproportionate," but simply more accurate. For instance, if the majority of secondary customers and load are from a particular rate class, that rate class causes the majority of secondary cost and this is more precisely revealed with the use of MDS.

Q. Do you recommend continuing to use MDS for Gulf in this case?

A. Yes, I do. I believe that this methodology provides the most appropriate cost assignments to assess rate class returns and to serve as a basis for rate design.

Q. In your opinion, are the results of the recommended cost-of-service study accurate representations of the rates of return by jurisdiction and rate class?

A. Yes. The results shown on Schedule 1 of the cost-of-service study in Exhibit MTO-2 are indeed fair and accurate statements of cost causation. The rates of return produced by jurisdiction and by rate class for Gulf's test year are fair and accurate indications of how the rate classes are covering costs.

Q. Does this conclude your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
Lee P. Evans
Docket No. 160186-EI
In Support of Rate Relief
Date of Filing: October 12, 2016

Q. Please state your name and business address.

A. My name is Lee Evans. My business address is One Energy Place, Pensacola, Florida 32520.

Q. What is your position?

A. I am the Pricing Supervisor for Gulf Power Company (Gulf or the Company).

Q. What are your responsibilities as Pricing Supervisor?

A. My pricing responsibilities include planning, implementation and evaluation of retail electric prices for Gulf. This includes development and design of new rates and the administration of current rates. I supervise the planning and production of cost studies that serve as an input toward pricing. I also supervise the planning, collection, analysis and reporting of load research information for Gulf.

Q. Please state your prior work experience and responsibilities.

A. I began my career with Southern Company Services in 2006 and worked in various roles within the Accounting and Corporate Finance organizations. I joined Gulf's Customer Accounting group in 2011 working on rate implementation, industrial customers' billing, revenue accounting, and billing system changes. I later joined the Regulatory and Cost Recovery organization focusing on rate design and tracking for cost recovery clauses and the coordination of regulatory filings. In January 2015, I assumed my current responsibilities.

Q. What is your educational background?

A. I received a Bachelor of Science degree in Financial Management from Clemson University and a Master of Science degree in Finance from Georgia State University. I am a licensed Certified Public Accountant and a member of the American Institute of Certified Public Accountants. I have also served as an Adjunct Instructor of Finance for the University of West Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and describe the package of rates that has been developed to recover Gulf's revenue requirement, including the increase requested, in a way that is fair and equitable to Gulf's customers. I also explain and support other non-revenue related tariff changes proposed by Gulf to improve our overall pricing menu. Finally, I discuss the load research used in the cost-of-service study.

Q. How does your testimony relate to Gulf Witness McGee's testimony?

A. Mr. McGee discusses the justification and need for the Advanced Pricing Package described in his testimony. I support the calculations used in rate design, including all calculations presented in Mr. McGee's testimony.

Q. Are you sponsoring any exhibits?
A. Yes. Exhibit LPE-1, consisting of three schedules, was prepared under my supervision and direction, and the information contained therein is true and correct to the best of my knowledge and belief.

Q. Are you sponsoring any of the Minimum Filing Requirements (MFRs) submitted by Gulf?
A. Yes. These are listed in Schedule 1 of my exhibit. To the best of my knowledge, the information contained in these MFRs is true and correct.

I. RATE DESIGN PRINCIPLES AND METHODOLOGY

Q. Are there any overall goals that Gulf seeks to achieve through its rate design and proposed pricing?
A. Yes. Gulf's pricing package represents a continuation of our strategy of simplicity in our rates, consideration of costs, and recognition of the need to use pricing as a tool to improve customer satisfaction by offering options to customers to manage their electric usage. Gulf's rate design and proposed pricing provides equity and fairness among customers, and enhances Gulf's conservation efforts. It also provides for administration of the rates in an objective and non-discriminatory manner.

Q. Please provide an overview of Gulf's retail rates.

A. Gulf's Tariff for Retail Electric Service (Tariff) contains rate schedules for the various types of customers served by Gulf. These include residential customers; small, medium, and large business customers; and outdoor service such as street lighting. Each of these types of customers is served through separate rate schedules, which are designed to reflect the differences in the usage characteristics of each customer type and the difference in cost incurred by Gulf in supplying service to each customer type.

Q. Please describe, in general, these rate schedules.

A. Rate schedules generally contain specific prices that are to be applied to each customer's electric usage amount. Most rate schedules incorporate a Base Charge, a fixed amount which includes the costs of providing service that do not vary with usage. Another price component is the Energy Charge, which reflects costs associated with supplying the amount of electricity consumed throughout the month. Rate schedules may also include a Demand Charge component, which reflects the Company's cost of supplying service to meet the maximum demand the customers place on Gulf's system. Finally, in addition to the specific prices, the rate schedules contain terms and conditions. Together, the prices, terms, and conditions describe the way customers' monthly bills are determined.

Q. Besides the rate schedules, are there other contents of Gulf's Tariff that are relevant to the determination of customers' bills?

A. Yes. Gulf's Tariff also includes rules and regulations, as well as technical terms and abbreviations that are relevant to rate administration. Rate schedules often contain words and phrases whose meanings or implications are explained in these other sections of the Tariff.

Q. Please identify the major steps necessary to translate an increased revenue requirement into a specific set of rates.

A. There are two basic steps in this process. First, the total amount of the increased revenue sought is allocated, or spread, across the various customer classes. In making this allocation, consideration is given to the relative costs of service for each rate class, as well as fairness and equity. The second step is to design the specific rate components for each rate class. In developing these rate components – Base Charges, Energy Charges, and Demand Charges – we again consider the costs associated with providing service, as well as fairness and equity. Other considerations at this step include rate stability, customer acceptance and understanding, effects on conservation and energy efficiency, and objectivity in administration of the rates.

II. ALLOCATION OF RATE INCREASE TO RATE CLASSES

Q. Turning to the first step of the rate design process, how did you allocate the revenue increase across the customer classes?

A. The proposed rates are designed to achieve Gulf's requested overall revenue requirement, including the requested base rate increase of $106,782,000 provided by Gulf Witness Ritenour. The increase to base rate revenue has been allocated across the various rate classes as shown in MFR E-8. The results of the cost-of-service study prepared and presented by Gulf Witness O'Sheasy serve as an important guide. The overall base rate increase of 19.2 percent has been allocated across rate classes in order to move the rate of return for each class toward the overall retail average rate of return. In doing so, we have respected certain traditional limits. First, because an overall rate increase is requested, no rate class is assigned a rate decrease. Second, the base rate percentage increase for each class is limited to no more than 1.5 times the overall retail average percentage increase to base rates. As shown in MFR E-8 and summarized on Schedule 2 of my exhibit, the increases allocated to each rate class represent base rate increases of 15.9 percent to 28.8 percent.

Q. Please explain the information labeled "Indexed Rate of Return" on Schedule 2 of your exhibit.

A. These index figures show how the rate of return for a rate class compares to the Company's overall retail rate of return. A 1.00 indexed rate of return was achieved for classes representing almost 94 percent of Gulf's retail customers.

III. RESIDENTIAL RATES

Q. What changes to residential rates does Gulf propose in order to recover the allocated share of revenue requirements from that rate class?

A. In developing residential rates that achieve the overall proposed revenue level for that rate class, we have included an increase to the Base Charge in Gulf's residential rates, as described by Mr. McGee. The Base Charge for residential rates will continue to be billed as a daily amount as accepted and approved in Docket No. 130140-EI. We also propose a corresponding decrease to the Energy Charge components of residential rates as described by Mr. McGee. The calculations supporting these residential rates were prepared under my supervision and provided to Mr. McGee.

Q. Is Gulf proposing any new rate options for residential customers?

A. Yes. As stated by Mr. McGee, Gulf is proposing optional demand rates for residential customers. These optional rates will consist of a Residential Service - Demand (RSD) rate and a Residential Service - Demand Time-of-Use Conservation (RSDT) rate. We also are proposing one new rate rider, the Low Income Rider, as described by Mr. McGee, to accompany the new rate structure. The calculations supporting these residential rates and riders were prepared under my supervision and provided to Mr. McGee.

Q. How do these new residential rates work?

A. The Residential Service-Demand rate consists of a daily Base Charge, an Energy Charge, and a Maximum Demand Charge based on hourly demand. This structure is similar to demand rates currently offered to Gulf's business customers.

The Residential Service-Demand Time-of-Use Conservation rate consists of a daily Base Charge, an Energy Charge, a Maximum Demand Charge based on hourly demand, and an On-Peak Demand Charge based on hourly demand. Again, this structure is similar to demand time-of-use rates currently offered to Gulf's business customers. This time-of-use rate, RSDT, has been designed following a technique established in Gulf's last two rate cases. This approach uses a Base Charge and Energy Charge that is the same for both Rate RSD and Rate RSDT, with the time differentiation in the demand charge component.

Q. How does Gulf plan to educate residential customers on demand rates?

A. Gulf's website will have educational graphics and narratives available to educate residential customers on demand billing and how billing demand might be impacted by usage patterns. Customer Service Representatives and Residential Marketing Representatives will also be trained on the new residential demand rates to assist customers. This will enable customers to better judge if these optional demand rates would be beneficial to them.

IV. SMALL AND MEDIUM BUSINESS RATES

Q. What changes are you proposing to the rates serving small and medium size business customers to implement the rate increase?

A. First, we propose changes to the Base Charge components of these rates. The customer-related unit costs from Mr. O'Sheasy's cost-of-service study support the proposed Base Charge levels. Secondly, for the rates with distinct Demand Charges, the proposed rate design preserves the relationships between Demand and Energy Charges of the present rates and includes Demand Charges that are reasonably based on demand-related costs. Finally, the overall rate levels have been designed to achieve the requested revenue for these rate classes.

V. LARGE BUSINESS RATES

Q. Please describe the changes proposed to rates serving large business customers in order to implement the base rate increase.

A. The proposed rates for large business customers are designed to achieve the total test year base rate revenue requirement for these rate classes. Rates with distinct Demand Charges have been developed preserving the basic relationships between Demand and Energy Charges found in current rates.

The companion time-of-use rates, Rates General Service - Demand Time-of-Use Conservation (GSDT) and Large Power Service – Time-of-Use Conservation (LPT), have been designed following a technique established in Gulf's last two rate cases. This approach uses energy prices that are the same for both the standard rates and their respective time-of-use counterparts, with the time differentiation in the Demand Charge component. The rate design also preserves, to the extent practical, respective class On-Peak and Maximum Demand Charge relationships.

The Base Charges for these rate schedules are set mindful of the customer-related costs determined in the cost-of-service study sponsored by Mr. O'Sheasy.

Q. What other changes are proposed to business rates?

A. Rate Schedules GSDT and LPT currently offer a critical peak rate option. This critical peak option allows business customers to participate in a form of critical peak pricing. Structurally, the option introduces a third Demand Charge for customers on the GSDT and LPT rates. This third tier Demand Change is in addition to the Maximum Demand Charge, On-Peak Demand Charge, Energy Charge and Base Charge rate components found in these rates. The Demand Charge applicable to the critical peak period is higher than the On-Peak Demand Charge, but customers with load management abilities may substantially reduce their demand during these short periods. We believe the relationship among the price tiers for the LPT critical peak option needs to be improved and propose several modifications to the critical peak option for this rate. Additionally, we propose to remove the critical peak option for GSDT.

Q. What changes do you propose to improve the LPT critical peak rate option?

A. Gulf proposes to use the Energy Conservation Cost Recovery (ECCR) Clause to achieve the price differential among the three Demand Charge tiers for the LPT critical peak option. Currently, the price differentials among the tiers are achieved by setting different base rate Demand Charges. In the proposed method, the base rate Maximum Demand Charge and On-Peak Demand Charge will be the same for LPT and LPT critical peak option. The differentiation in the overall prices for the critical peak option will be achieved by applying different ECCR charges for On-Peak Demand and Critical Peak Demand. The ECCR charges will be determined in the ECCR docket on an annual basis. Additionally, Gulf proposes to modify the limitations on when a critical peak period can be issued. Gulf Witness Floyd discusses the benefits of these changes and the mechanics of determining ECCR charges.

Q. Why is Gulf proposing to remove the critical peak option from Rate Schedule GSDT?

A. Gulf is proposing to remove the critical peak option for GSDT due to a lack of customer response. The option has been available since April 2012 and no customers have ever taken service under this option.

VI. BUSINESS INCENTIVE RIDERS

Q. Is Gulf proposing any changes to its existing business incentive rate riders?

A. Yes. Gulf is proposing updates to the employment verification process and the definition of qualifying new load for our three pilot Business Incentive Riders, Rate Schedule Small Business Incentive Rider (SBIR), Rate Schedule Medium Business Incentive Rider (MBIR), and Rate Schedule Large Business Incentive Rider (LBIR). We also propose a modification to the employment requirement in the LBIR. Finally, Gulf is proposing to remove the expiration date on these three pilot riders (SBIR, MBIR, and LBIR). Gulf Witness Terry provides a description of the need for, and expected benefits of, these modifications. These riders can be found on the revised tariff sheets attached as Schedule 3 of my exhibit.

Q. How do these incentive riders work?

A. The structures of the riders are straightforward. All provide for incentives in the form of credits applied to the base Demand and Energy Charges of the customer's applicable rate schedule. They require a minimum five-year term, and the credits applied to the base Demand and Energy Charges are reduced each year of the five-year term. The specific base rate charge credits are shown on the second page of each of the riders. Also, the riders are applicable only to new load. New load is that which is added after the effective date of the riders. These rate riders include in their respective Applicability sections a list of Rate Schedules with which they may be combined. The riders also require documentation verifying that the availability of the rider is a significant factor in the customer's location or expansion decision.

Q. What is the proposed modification to the Large Business Incentive Rider?

A. We are requesting to modify the employment requirement on the LBIR. Currently, the LBIR requires the prospective customer to have 25 full-time employees per 1,000 kW of qualifying load. We propose that the employment requirement for this rider be changed to 50 full-time employees in total. Ms. Terry provides the rationale for this modification.

Q. Is Gulf proposing any new business incentive riders?

A. Yes. Gulf is proposing the Extra-Large Business Incentive Rider (XLBIR), which can be found on the revised tariff sheets attached as Schedule 3 of my exhibit. The XLBIR will have a similar structure as the current business incentive riders with the following modifications. The XLBIR will only be available to larger customers with 5 MW or more of qualifying load. The XLBIR will also require a minimum ten-year term with the credits applied to the base Demand and Energy Charges being reduced each year of the ten-year term. Gulf proposes that the employment requirement for this rider be 50 full-time employees, consistent with the proposed modifications to the LBIR. Ms. Terry provides a description of the need for, and expected benefits of, this rate rider.

VII. OTHER TARIFF CHANGES

Q. Is Gulf proposing any general changes to its rates for unmetered outdoor service?

A. Yes. Gulf is proposing to remove some lighting fixtures from Rate Schedule OS and close others for new installations. Gulf is also proposing to close for new installation some additional facilities options. Gulf has modified Form 19 – Optional Relamping Service Agreement Customer-Owned Street and General Area Lighting, Form 20 – Optional Up Front Payment of Fixture(s), and Form 24 – Customer-Owned Lighting Agreement (Without Relamping Service Provisions) to reflect these changes. Gulf also proposes to modify Form 4 – Outdoor Service - Lighting Pricing Methodology.

Q. Please describe why you are proposing these changes to Gulf's outdoor service menu.

A. Gulf is proposing to remove six fixtures that have been rendered obsolete by technology advances. None of these fixtures are currently in place, and none are anticipated to be sold. Additionally, Gulf is proposing to close for new installation all Metal Halide fixtures and 21 High Pressure Sodium fixtures, which are being phased out by manufacturers in favor of customers' preference for LED fixtures. We also propose to close for new installation 16 LED fixtures that have also been rendered obsolete by technology advances. Last, Gulf is proposing to close three pole options offered as additional facilities. These poles have been rendered obsolete by cheaper or more reliable options currently available.

Q. What modifications are proposed to Form 4?

A. Gulf proposes to revise Form 4 to update the labor rates and overhead rates and to include Revenue Tax in the Maintenance Charge for LED Fixtures.

Q. Has Gulf designed the proposed rates in this case recognizing and allowing for customer migration across rates?

A. Yes. As in previous cases, the proposed rates are designed recognizing that customers may migrate, or move, to different rates for which they are eligible. This occurs when changes in rate levels, structure, or availability make alternative rates more economical. Recognition of this migration should be handled by allowing consideration of such migrations in the rate design process, as we have done, and as the Commission has approved in prior rate orders.

Q. Is Gulf proposing any non-revenue related tariff changes to its Tariff in this case?

A. Yes. We propose a number of ministerial changes which are intended to update portions of Gulf's Tariff which have become stale or are in need of clarification. These proposed changes generally serve to clarify contract forms and correct references. The proposed changes do not add or increase any charges for Gulf's services.

VIII. LOAD RESEARCH

Q. Please provide an overview of Gulf's Cost of Service Load Research.

A. Gulf routinely performs Cost of Service Load Research every three years in accordance with FPSC Rule 25-6.0437. This Load Research is designed to estimate the monthly coincident peak kW demand (MCP) and non-coincident peak kW demand (NCP) of Gulf's customers, grouped by rate class. Load Research is conducted following a sampling plan that is designed to provide an accurate estimate of the peak demands. That sampling plan is filed with the Commission for review and approval in the year prior to data collection. In the months following the data collection year, Gulf analyzes the collected load research data and submits a report to the Commission for review. That report contains the monthly coincident peak demands, monthly non-coincident peak demands, annual energy, and number of customers for each rate class, as well as other details regarding sample sizes and statistical accuracies.

Q. What load research results are being used in this proceeding?

A. Gulf's 2015 Cost of Service Load Research Study, filed with the Commission on June 9, 2016, pursuant to Rule 25-6.0437, provides the load research basis of the cost-of-service study in this proceeding. These results are appropriate and used in the cost-of-service study prepared and filed by Mr. O'Sheasy in this case.

Q. Does Gulf's 2015 Cost of Service Load Research sample design meet the requirements of the Cost of Service Load Research Rule 25-6.0437?
A. Yes. The sample design meets or exceeds the requirements of the referenced rule.

IX. CONCLUSION

Q. Are the rates and charges proposed in this case fair, just and reasonable?
A. Yes. The rates, prices, and terms shown on the tariff sheets filed with this case will achieve the requested revenue requirement; represent fair, just and reasonable pricing of Gulf's retail electric services; improve our pricing as a customer service tool; and provide opportunities to improve customer satisfaction with Gulf. I have included all the revised tariff sheets in Schedule 3 of my exhibit.

The Cost of Service Load Research used in this proceeding has been previously filed with the Commission, meets the Commission's requirements in Rule 25-6.0437, and is appropriate for use by Mr. O'Sheasy in the cost-of-service study.

Q. Does this conclude your testimony?
A. Yes.

ERRATA SHEET

Direct Testimony of: **James R. Dauphinais**
Date: **January 13, 2017**
Docket Nos.: **160186-EI / 160170-EI**

Page	Line	Error or Amendment	Reason For Change
15	4	"2000" should be "2003"	Correction
15	16	"2000" should be "2003"	Correction

Under penalties of perjury, I declare that I have reviewed my January 13, 2017 Direct Testimony and together with the corrections and amendments listed above, hereby subscribe to the same.

James R. Dauphinais
James R. Dauphinais

March 10, 2017
Date

DIRECT TESTIMONY

OF

JAMES R. DAUPHINAIS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 160186-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

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

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

A. I am appearing on behalf of the Florida Office of Public Counsel ("OPC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. During my employment with Northeast Utilities Service Company ("Northeast Utilities"), prior to the implementation of FERC Order Nos. 888 and 889, the transmission planning organization I was employed within was integrated with, and part of the same functional organization, as Northeast Utilities' generation planning organization. This integration led to significant involvement by transmission planning, including myself, in resource planning analyses (e.g., the analysis of the potential net benefit of retirement of existing generation resources) and resource planning in transmission planning analyses (e.g., whether to proceed with economic transmission upgrades). In addition, while employed at Northeast Utilities, I made significant usage of the General Electric Company Multi-Area Production Simulator ("MAPS") to analyze the generation production cost associated with various transmission operating and planning alternatives on the Northeast Utilities system.

Subsequently, during my employment with BAI since 1997, I have become further involved with resource planning issues initially in support of my colleagues at BAI and later in a lead position. This work has included the review of electric utility resource plans, the review of proposed certificates of public convenience and necessity for new electric utility generation resources, the forecasting of future market prices, the forecasting of future utility rates and the evaluation of long-term power supply options. I have conducted this work both for intervenors in regulatory proceedings and specific retail end-use customer clients of BAI who were evaluating their future power supply options. I have also been extensively involved in the development of Independent

System Operator ("ISO") and Regional Transmission Organization ("RTO") - administered power markets including, but not limited to, issues related to markets for energy, operating reserves and capacity.

Q. PLEASE IDENTIFY SOME OF THE CASES IN WHICH YOU PROVIDED TESTIMONY WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. In the past 12 years, I have provided testimony on resource planning and/or the prudency issues related to the resource planning in Indiana Utility Regulatory Commission ("IURC") Cause No. 42643, Louisiana Public Service Commission ("LPSC") Docket No. U-30192, IURC Cause No. 43393, IURC Cause No. 43396, Colorado Public Utilities Commission ("CPUC") Docket Nos. 09A-324E and 09A-325E, IURC Cause No. 43956, IURC Cause No. 44012, New Mexico Public Regulatory Commission ("NMPRC") Case No. 13-00390-UT and NMPRC Case No. 15-00261-UT.

In a number of these proceedings, I either had extensive involvement in the review of the utility's Strategist® analysis, or had a Strategist® analysis performed under my direction and supervision based upon data provided by subject utility.[1]

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY HEREIN?

[1]Strategist®, which includes a module called Proview®, is a computer software tool produced by Ventyx that allows resource planners to examine a very large number of alternative resource portfolios with the goal of identifying through an optimization algorithm the most cost effective resource portfolio for an electric utility. It can also be used in a probabilistic mode to test the robustness (i.e., risk) of specific resource portfolios over a wide range of assumption variations. Strategist® is used by Gulf in the development of its annual 10-year site plans. Other commercial software tools that have some or all of the functionality of Strategist® include System Optimizer®, PLEXOS® and Aurora XMP®.

A. I present testimony with respect to the request of Gulf Power Company ("Gulf" or "Company") to assign the cost of its portion of the Scherer Unit 3 generation facility that is not committed to wholesale unit power sales[2] to its retail customers. This includes addressing Gulf's claims regarding the existence of a regulatory compact, whether assignment of Scherer Unit 3 to retail customers is a prudent resource planning decision by Gulf on behalf of its native load customers,[3] and whether the Scherer Unit 3 capacity is used and useful with respect to serving Gulf's native load customers.

The fact that I do not address any other particular issues in my testimony or am silent with respect to any portion of Gulf's direct testimony in this proceeding should not be interpreted as an approval of any position taken by Gulf in direct testimony.

Q. PLEASE DESCRIBE WHAT YOU REVIEWED AND ANALYZED IN PREPARING YOUR DIRECT TESTIMONY.

A. I have reviewed and analyzed: (i) Gulf's application; (ii) the Direct Testimony and Exhibits of its witnesses Xia Liu, Jeffrey Burleson and Terry Deason; (iii) Gulf's response to interrogatories and requests for production documents related to the issues addressed by my testimony; (iv) the deposition transcript of Xia Liu; (v) the Commission's November 22, 2016 Order in Docket No. 160007-EI; and (vi) certain Gulf and The Southern Company ("Southern") filings with the Federal Energy Regulatory Commission ("FERC") and Securities and Exchange Commission

[2]For purposes of this testimony, when using this term, I am referring to the multi-year firm wholesale power sales Gulf has made from its share of Scherer Unit 3.

[3]Gulf's native load customers, as Gulf defines it, consist of both its retail customers and its wholesale requirements customers. They do not include Gulf's wholesale unit power sales customers or any other wholesale customers.

("SEC"). I applied my knowledge and experience in conducting my review and analysis of the foregoing.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I conclude and recommend the following:

- Through its actions over the past 10 to 15 years, Gulf has broken any regulatory compact it believes it entered with the Commission over 35 years ago with respect to Scherer Unit 3 by treating the proposed assignment of Scherer Unit 3 capacity to its retail customers as a revenue source option to support Gulf's earnings rather than as a resource option available to serve Gulf's retail customers;

- Based on Gulf's actions with respect to Scherer Unit 3 over the past 35 years, the Commission's evaluation of whether the cost for Scherer Unit 3 should be assigned to Gulf's retail customers should be conducted in the same manner as any other evaluation of an incremental resource addition by Gulf;

- Specifically, Gulf failed to demonstrate the Scherer Unit 3 capacity is both needed by its retail customers, and is the most cost-effective resource option available to its retail customers, such that the proposed assignment of the capacity to its retail customers is consistent with providing reliable electric service to those customers at the lowest reasonable cost -- Gulf has failed to demonstrate this is the case;

- As a result, Gulf has not met its burden to demonstrate that its proposed assignment of Scherer Unit 3 capacity to serve its retail customers was a prudent decision on behalf of its retail customers, or that the capacity is used and useful with respect to serving those customers; and

- For all of the foregoing reasons, the Commission should reject Gulf's proposal in this proceeding to assign the cost of Scherer Unit 3 capacity to its retail customers.

In her direct testimony, OPC witness Donna Ramas presents specific revenue requirement adjustments to implement my recommendation that the Commission reject Gulf's proposal in this proceeding to assign Scherer Unit 3 capacity to its retail customers.

Q ARE THERE OTHER IMPLICATIONS WITH RESPECT TO YOUR RECOMMENDATION?

A Yes. In its November 22, 2016 Order in Docket No. 160007-EI, the Commission deferred for resolution whether to include in Gulf's Environmental Cost Recovery Clause ("ECRC") certain environmental compliance investments and expenses associated with Gulf's share of Scherer Unit 3 that is not committed to wholesale unit power sales after December 31, 2015. Specifically, the Commission allowed the initial inclusion of the costs in Gulf's ECRC subject to a determination in the current proceeding with respect to whether any of the costs of Scherer Unit 3 are recoverable from Gulf's retail customers. As a result, if my recommendation to the Commission in this current proceeding is accepted, Gulf should not be permitted to recover any Scherer Unit 3 costs in its ECRC and should have to refund any amounts already collected from its retail customers.

<u>II. REGULATORY TREATMENT OF SCHERER UNIT 3 CAPACITY</u>

A. Background

Q. PLEASE DESCRIBE SCHERER UNIT 3.

A. Scherer Unit 3 is an 848 MW Powder River Basin ("PRB") coal-fired steam generation facility located in Georgia that began commercial operation on January 1, 1987. Gulf owns an undivided 25% (approximately 212 MW) share of the generation facility. Except on a very limited basis, Gulf's entire share of Scherer Unit 3 was committed to Gulf's firm wholesale power customers from the beginning of its operation in 1987 until the end of 2015 -- a total of 29 years.

Starting on January 1, 2016, Gulf alleges that it began making the uncommitted portions of its Scherer Unit 3 capacity available to its retail customers on a dedicated basis (first 110 MW beginning on January 1, 2016 and then another 50 MW beginning on June 1, 2016). Gulf has termed this a "rededication" of Gulf's share of Scherer Unit 3 to Gulf's retail customers. However, over the operating life of Scherer Unit 3, the Commission has never recognized any more than 19 MW of Scherer Unit 3 being dedicated to serve Gulf's retail customers, and even that 19 MW of capacity was later committed by Gulf to its long-term firm wholesale power sales. Furthermore, this recognition was limited to the determination of a one-time tax refund amount to retail customers, where the effect of the recognition was to reduce the amount of the refund. Scherer Unit 3 has never been included in Gulf's retail rates.

Q HAS GULF EVER SHARED WITH RETAIL CUSTOMERS THE PROFITS FROM WHOLESALE UNIT POWER SALES FROM ITS SHARE OF SCHERER UNIT 3?

A No, it has not. While Gulf's retail customers have never been responsible in rates for any portion of Scherer Unit 3, neither did Gulf's retail customers ever receive the benefit of any portion of Gulf's profits from the wholesale unit power sales from its share of Scherer Unit 3 during the 29-year period that ended in December 2015.

Q DID GULF MAKE ITS WHOLESALE UNIT POWER SALES FROM SCHERER UNIT 3 PURSUANT TO COST-BASED RATES OR MARKET-BASED RATES?

A. The first round of its firm wholesale power sales from its share of Scherer Unit 3, which ended in May 2010, were all made pursuant to cost-based rates set by the FERC (Gulf's response to Citizens' Interrogatory No. 175).[4] However, the second round of firm wholesale power sales, which began in June 2010, were made pursuant to market-based rates authorized by FERC. Under market-based rates, Gulf was allowed to earn whatever price it was able to obtain from its counterparties, which allowed it the opportunity to earn revenues in excess of its cost to provide the sales. Thus, it had the opportunity under market-based rates to earn an implied return on equity in excess of any that might be authorized under retail rates by this Commission or cost-of-service wholesale rates authorized by FERC.

Q IS THERE ANY DATA AVAILABLE WITH RESPECT TO THE REVENUES EARNED BY GULF FROM ITS WHOLESALE UNIT POWER SALES FROM ITS SHARE OF SCHERER UNIT 3 FROM JANUARY 1987 THROUGH MAY 2010 AND FROM JUNE 2010 THROUGH DECEMBER 2015?

A Yes. These sales and other information regarding Gulf's share of Scherer Unit 3 were reported in Gulf's annual FERC Form 1 filings. I have summarized this information below in Table JRD-1.[5]

[4]In Exhibit No. JRD-1, I have provided a copy of all of Gulf's responses to interrogatories and requests for production of documents that I cite to in my direct testimony.

[5] For some of the years summarized in Table JRD-1, most significantly from 1987 through 1992, the total MWh sold under the wholesale unit power sales agreements exceeded the total reported generation from Gulf's share of Scherer Unit 3. I have assumed this was due to supplemental energy sales under those agreements principally driven by low capacity factor issues with Scherer Unit 3. To estimate the net revenue amounts presented in Table JRD-1, I assumed the per MWh cost of those supplemental energy sales was roughly equal to the per MWh fuel cost of Scherer Unit 3.

TABLE JRD-1

Summary of Gulf Power Company
Wholesale Unit Power Sales from Scherer Unit 3
(1987-2015)

Year	Revenue Earned ($millions)	MWh Sold	Revenue Earned per MWh Sold	Fuel Expense per MWh	Net Revenue per MWh Sold	Total Net Revenue ($millions)	Total kW Sold	Net Revenue per kW Sold
1987	96.34	1,553,013	$ 62.03	$ 31.23	$ 30.80	47.83	185,000	$ 259
1988	91.03	1,444,202	$ 63.03	$ 26.65	$ 36.38	52.53	149,000	$ 353
1989	51.60	1,154,136	$ 44.70	$ 26.21	$ 18.49	21.34	149,000	$ 143
1990	51.88	1,265,359	$ 41.00	$ 22.12	$ 18.88	23.89	149,000	$ 160
1991	47.66	1,103,275	$ 43.19	$ 20.87	$ 22.32	24.63	149,000	$ 165
1992	51.25	1,041,512	$ 49.21	$ 20.75	$ 28.46	29.65	201,000	$ 147
1993	49.40	972,336	$ 50.80	$ 18.85	$ 31.96	31.07	196,000	$ 159
1994	42.70	839,255	$ 50.88	$ 17.65	$ 33.23	27.89	177,000	$ 158
1995	41.55	944,667	$ 43.98	$ 17.02	$ 26.97	25.47	212,000	$ 120
1996	45.22	1,069,000	$ 42.30	$ 17.16	$ 25.15	26.88	212,000	$ 127
1997	43.00	923,406	$ 46.56	$ 18.44	$ 28.13	25.97	212,000	$ 123
1998	36.93	703,031	$ 52.52	$ 17.27	$ 35.25	24.79	212,000	$ 117
1999	40.18	1,044,337	$ 38.47	$ 17.16	$ 21.31	22.26	212,000	$ 105
2000	41.99	1,094,292	$ 38.37	$ 18.51	$ 19.87	21.74	212,000	$ 103
2001	47.08	1,276,557	$ 36.88	$ 18.44	$ 18.44	23.54	212,000	$ 111
2002	48.49	1,286,320	$ 37.70	$ 20.37	$ 17.33	22.30	212,000	$ 105
2003	49.52	1,387,709	$ 35.69	$ 19.96	$ 15.72	21.82	212,000	$ 103
2004	48.17	1,486,600	$ 32.41	$ 17.47	$ 14.94	22.21	212,000	$ 105
2005	54.09	1,668,819	$ 32.41	$ 17.66	$ 14.75	24.61	212,000	$ 116
2006	56.16	1,406,049	$ 39.94	$ 20.55	$ 19.39	27.26	212,000	$ 129
2007	54.35	1,590,360	$ 34.17	$ 20.66	$ 13.52	21.50	212,000	$ 101
2008	55.73	1,296,555	$ 42.99	$ 21.95	$ 21.03	27.27	212,000	$ 129
2009	57.61	1,372,658	$ 41.97	$ 21.37	$ 20.60	28.28	212,000	$ 133
2010	66.18	1,218,055	$ 54.33	$ 23.65	$ 30.69	37.38	212,000	$ 176
2011	97.84	1,605,570	$ 60.94	$ 25.83	$ 35.11	56.37	212,000	$ 266
2012	72.81	556,619	$ 130.80	$ 27.57	$ 103.23	57.46	212,000	$ 271
2013	77.80	767,743	$ 101.34	$ 27.87	$ 73.47	56.40	212,000	$ 266
2014	89.42	1,125,554	$ 79.45	$ 28.98	$ 50.47	56.81	212,000	$ 268
2015	74.89	595,311	$ 125.81	$ 28.23	$ 97.58	58.09	212,000	$ 274

Source: Gulf's FERC Form 1 Filings

Q. WHAT DOES THE "TOTAL NET REVENUE" THAT IS SHOWN IN YOUR TABLE JRD-1 REPRESENT?

A. It represents the total revenue Gulf earned after fuel expenses. It is essentially the contribution made to cover the non-fuel expenses, including non-fuel O&M expenses, depreciation, return and taxes for the portion of the Gulf share of Scherer Unit 3 that has been sold pursuant to the wholesale unit power contracts. Note that on a per kW basis, these net revenues jumped considerably after Gulf's wholesale unit power sale contracts fully migrated to market-based rates in 2011. (The portion of this contribution left after covering Gulf's non-fuel O&M, depreciation, interest and other non-fuel expenses for Scherer Unit 3 would be the pre-tax profit earned by Gulf from sales under the contracts.)

Q. HOW DOES THE NET REVENUE ON A PER KW SOLD BASIS EARNED BY GULF IN 2015 UNDER THE WHOLESALE UNIT POWER SALES CONTRACTS COMPARE WITH THE PER KW NET REVENUE GULF WOULD EARN UNDER RETAIL RATES PURSUANT TO GULF'S PROPOSAL TO ASSIGN 160 MW OF ITS SCHERER UNIT 3 CAPACITY TO ITS RETAIL CUSTOMERS?

A. The net revenue from the wholesale unit power sale contracts was $274 per kW in 2015. Under its proposed base rates, Gulf's non-fuel revenue requirement for 160 MW (160,000 kW) of Scherer Unit 3 would be $19.4 million (Gulf's response to Citizens' Interrogatory No. 177). Adding in the portion of Scherer Unit 3 costs that would be recovered through Gulf's ECRC for the test year would raise this to a total of

$34.9 million of non-fuel clause revenue or $212 per kW during the test year. This is $62 per kW less than the $274 per kW amount Gulf collected under its wholesale unit power sale contracts in 2015. Thus, under market-based rates in 2015, Gulf collected approximately $62 per kW more for Scherer Unit 3 capacity than it presumably would have if the capacity had instead been included in Gulf's retail rates. For the 160 MW of Scherer Unit 3 capacity that Gulf proposes to include in retail rates in the test year for this proceeding, this provided Gulf approximately $10 million of additional annual revenues for Scherer Unit 3 versus what Gulf would have presumably been able to earn under retail rates for Scherer Unit 3.[6] As I have noted, Gulf retained all of its profits over the years from its wholesale unit power sales from Scherer Unit 3 -- none of those profits were ever shared with its retail customers.

Q. WAS GULF REQUIRED BY FERC TO SELL POWER AT MARKET-BASED RATES STARTING IN 2010, OR WAS THAT A CHOICE MADE BY GULF?

A. No, it was a choice made by Gulf. Gulf sought authorization from FERC to sell power at market-based rates. In addition, even when such authorization was obtained from FERC, Gulf still could have chosen to continue to sell power from Scherer Unit 3 pursuant to cost-based rates rather than market-based rates. Instead, Gulf chose to use market-based rates for its wholesale unit power sales contracts starting in June 2010, and appears from its FERC Form 1 filings to have handsomely profited from that choice.

[6] $10 million ≈ 160,000 kW x $62 per kW.

Q. HAS GULF PREVIOUSLY ATTEMPTED TO INCLUDE A PORTION OF ITS SHARE OF SCHERER UNIT 3 IN BASE RATES?

A. Yes. As Gulf witness Deason indicates in his direct testimony, Gulf made a previous attempt to assign to its retail customers the cost of its share of Scherer Unit 3 that is not covered by wholesale unit power sales. Specifically, in its base rate proceeding in Docket No. 891345-EI, Gulf proposed to include in its retail rates 63 MW of Scherer Unit 3 capacity that was at the time not covered by its wholesale unit power sales contracts. In Order No. 23573 in that proceeding, the Commission denied Gulf's request. In its decision, the Commission found Gulf, and the Southern electric system as a whole, appeared to be well able to achieve their respective target planning reserve margins without the 63 MW of Scherer Unit 3 capacity. The Commission also noted that, by 1995, the entire 63 MW of Scherer Unit 3 capacity in question would be sold under wholesale unit power sales contracts, and would not be available to retail customers any sooner than 2010. Additionally, the Commission indicated the following:

> Under Southern's contract with Gulf States Utilities, Gulf had committed to sell 44 MW of Scherer 3 to Gulf States Utilities during the test year 1990 through May, 1992. Gulf States Utilities failed to perform its contractual obligations and on July 1, 1988, FERC ruled that Southern no longer had to perform under the contract. It is clear that Gulf would not have requested the 63 MW of Scherer to be put in rate base had Gulf States Utilities not defaulted on their contracts. When Gulf made the decision to purchase 25% of Scherer 3 it was aware of the potential that their contract with Gulf States Utilities might not be honored. Since the profits from the unit power sales go to Gulf's stockholder, they should bear the risk of default, and not Gulf's ratepayers. Therefore, we remove all of Plant Scherer from rate base. All profits and losses derive from unit power sales of Scherer, and any costs or benefits accruing from any settlement with Gulf States Utilities are to go to the stockholders of Gulf Power Company. Gulf's ratepayers, who will not see the profits from Gulf's unit power sales

> contracts, should not be required to pay when such a contract falls through.

(Order No. 23573 at page 13, included as page RC-13 of Mr. Deason's ExhibitJTD-2)

The importance of this last finding is that it shows that the Commission at the time was not going to allow Gulf to use its retail customers as the guarantor of cost recovery with respect to Gulf's losses in the wholesale market associated with its share of Scherer Unit 3, since all the profits from Gulf's wholesale unit power sales from Scherer Unit 3 go to Gulf's stockholder(s), and are not shared with Gulf's retail customers.

Q. IN HIS DIRECT TESTIMONY, MR. DEASON MAKES REFERENCE TO ANOTHER PROCEEDING INVOLVING A DETERMINATION WITH RESPECT TO THIS ISSUE. PLEASE ELABORATE ON THAT PROCEEDING AS WELL.

A. Mr. Deason is referring to the 1998 tax savings refund proceeding in Docket No. 890324-EI. It is important to recognize that Docket No. 890324-EI did not involve the setting of base rates. In that proceeding, for purposes of determining a one-time tax refund, the Commission in Order No. 23536 on September 27, 1990 allowed the imputation of 19 MW of Gulf's share of Scherer Unit 3, which up until that point had never been used to support Gulf's wholesale unit power sales, into rate base as an adjustment that reduced the tax refund due to retail customers. However, this decision did not go to the much more impactful question of whether any portion of Scherer Unit 3 (either the 19 MW or the other 44 MW) should actually be recoverable in Gulf's rates. This latter issue was addressed just six days later in Commission Order No. 23573 on October 3, 1990. As I have discussed above, the Commission in Order No. 23573 rejected the inclusion of any portion of Scherer Unit 3 in retail rates.

Q. DURING THE 29-YEAR PERIOD THAT ENDED IN DECEMBER OF 2015, WAS GULF'S SHARE OF SCHERER UNIT 3 THAT WAS COMMITTED TO ITS WHOLESALE UNIT POWER SALES AVAILABLE TO SERVE GULF'S RETAIL CUSTOMERS?

A. Gulf has indicated that, to the extent wholesale purchasers did not call upon the Scherer Unit 3 capacity committed to them, Scherer Unit 3 capacity was available to Gulf to: (i) serve Gulf's retail customers, (ii) be dispatched to meet other Southern operating company needs or (iii) make wholesale opportunity sales (Gulf's responses to Citizens' Interrogatories Nos. 171, 172 and 175). The extent, if any, to which such availability ever actually benefited Gulf's retail customers was not presented in Gulf's direct case in this proceeding.

Regardless, non-firm, as-available usage of Scherer Unit 3 by Gulf for Gulf's retail customers, by itself, would not justify inclusion of Scherer Unit 3 in Gulf's retail rates anymore than, for example, qualifying facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA") would be for making as-available energy sales to Gulf. The bottom line is that Gulf's retail customers could not rely on the non-firm, as-available energy actually being made available to them from Scherer Unit 3.

B. Treatment of Scherer Unit 3 in Gulf's Planning

Q. HOW HAS GULF TREATED ITS SHARE OF SCHERER UNIT 3 IN ITS RESOURCE PLANNING?

A. In every ten-year site plan that Gulf prepared from 2000 through 2015, its share of Scherer Unit 3 was included throughout the 10-year forecast period with a matching equal wholesale unit power sale obligation, which had the effect of entirely excluding Gulf's share of Scherer Unit 3 from being available to meet the resource planning needs of Gulf's retail customers. This is shown on Schedules 7.1 and 7.2 of each of these ten-year site plans. Even as late as in the 2015 Ten-Year Site Plan, Gulf was forecasting that its share of Scherer Unit 3 would be committed to Gulf's wholesale unit power sales through at least 2024. In addition, in each of Gulf's annual Ten-Year Site Plans from 2003 through 2015, Gulf consistently made the following statement:

> "Gulf has a 25% ownership in Unit 3 at Georgia Power Company's Scherer Electric Generating Facility which is completely dedicated to wholesale unit power sale contracts."[7]

There is absolutely no evidence in Gulf's annual ten-year site plans from 2000 through 2015 that Gulf ever had any intention of using its share of Scherer Unit 3 to serve or benefit Gulf's retail customers. Serving Gulf's retail customers appears as a new revelation in Gulf's 2016 Ten-Year Site Plan, which replaces the statement with respect to complete, unconditional dedication of Scherer Unit 3 to Gulf's wholesale

[7] 2003 Gulf Ten-Year Site Plan at 3; 2004 Gulf Ten-Year Site Plan at 3; 2005 Gulf Ten-Year Site Plan at 4; 2006 Gulf Ten-Year Site Plan at 4; 2007 Gulf Ten-Year Site Plan at 4; 2008 Gulf Ten-Year Site Plan at 4; 2009 Gulf Ten-Year Site Plan at 5; 2010 Gulf Ten-Year Site Plan at 4; 2011 Gulf Ten-Year Site Plan at 4; 2012 Gulf Ten-Year Site Plan at 5; 2013 Gulf Ten-Year Site Plan at 5; 2014 Gulf Ten-Year Site Plan at 5; and 2015 Gulf Ten-Year Site Plan at 4.

unit power sales contracts with the following new statements that are obviously tailored to the theme of Gulf's filed direct testimony in this proceeding:

> Gulf has a 25% undivided ownership share in Unit 3 and a proportional undivided ownership interest in the associated common facilities at the Scherer Electric Generating Facility located near Macon, Georgia. Gulf's ownership interest in Plant Scherer Unit 3 was acquired as part of its resource planning for meeting the long-term needs of its retail customers. With the encouragement and support of the FPSC, Gulf has historically committed its ownership interest in Plant Scherer to off-system sales through a succession of several wholesale power sales contracts since Unit 3 began commercial operation in 1987.

(Gulf's 2016 Ten-Year Site Plan at 4).

In addition, in its 2016 Ten-Year Site Plan 10-year forecast tables, Schedules 7.1 and 7.2, Gulf for the first time included no wholesale unit power sales obligations beyond the expiration of its latest Scherer Unit 3 wholesale unit power sales contracts in December 2015, May 2016 and December 2019 (Gulf 2016 Ten-Year Site Plan at 89-90).

Q. IS THIS THE ONLY EVIDENCE OF GULF HAVING A SUDDEN CHANGE IN ITS INTENTIONS FOR SCHERER UNIT 3?

A. No, it is not. In Southern's 2014 10-K filing with the SEC, Southern included the following statements with respect to the Scherer Unit 3 wholesale unit power sales contracts:

> Gulf Power serves long-term contracts associated with Gulf Power's co-ownership of a unit with Georgia Power at Plant Scherer, covering 100% of Gulf Power's ownership of that unit in 2015, and 41% for the next five years. These capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2014. Gulf Power is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on Gulf Power's earnings.

(The Southern Company 2014 10-K filing at I-14).

In its 2015 10-K filing, Southern included the following statements:

> Through 2015, capacity revenues represented the majority of Gulf Power's wholesale earnings. Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, Gulf Power currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Although Gulf Power is actively evaluating alternatives relating to this asset, including replacement wholesale contracts, the expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts will have a material negative impact on Gulf Power's earnings in 2016 and may continue to have a material negative impact in future years. In the event some portion of Gulf Power's ownership of Plant Scherer Unit 3 is not subject to replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market."

(The Southern Company 2015 10-K filing at I-14).

What in 2014 had been a "could have a material negative impact on Gulf Power's earnings" became in 2015 a "will have a material negative impact on Gulf Power's earnings in 2016 and may continue to have a material negative impact in future years." In addition, Southern reported in 2015 that an amount of Scherer Unit 3 might be sold into the Southern power pool or into the wholesale power market. There is no indication in either 10-K filing that Gulf might choose to seek to assign cost recovery for Scherer Unit 3 to its retail customers.

However, this all changed when Gulf delivered a letter to the Commission on May 5, 2016 requesting recognition of Gulf's ownership in Scherer Unit 3 as being in-service to retail customers when and as the contracts expire. Shortly thereafter, in its first quarter of 2016 10-Q filing, Southern indicated the following:

> Through 2015, capacity revenues from long-term non-affiliate sales out of Gulf Power's ownership of Plant Scherer Unit 3 (205 MWs) represented the majority of Gulf Power's wholesale earnings. The capacity revenues associated with these contracts covering 100% of Gulf Power's ownership represented 82% of Gulf Power's wholesale capacity revenues in 2015. Due to the expiration of a wholesale contract at the end of 2015 and another wholesale contract at the end of May 2016, Gulf Power's remaining contract in sales from the unit from June 2016 through 2019 will cover approximately 24% of the unit. The expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts are not expected to have a material impact on Southern Company's earnings. The alternatives Gulf Power is actively evaluating include, without limitation, rededication of the asset to serve retail customers for whom it was originally planned and built, replacement long-term wholesale contracts or other sales into the wholesale market, or an asset sale. On May 5, 2016, Gulf Power delivered a letter to the Florida PSC requesting recognition of Gulf Power's ownership of Plant Scherer Unit 3 as being in-service to retail customers when and as the contracts expire. The ultimate outcome of this matter cannot be determined at this time.

(The Southern Company First Quarter 2016 10-Q filing at 26).

Thus, Gulf in its proposal for Scherer Unit 3 in this proceeding is seeking to solve the earnings problem Southern had identified in its 2014 and 2015 10-K filings by calling upon Gulf's retail customers to assure cost recovery for its shareholders for Scherer Unit 3.

Q. HAS GULF PROVIDED ANY STUDIES OR ANALYSIS SHOWING IT CURRENTLY HAS A NEED FOR ADDITIONAL CAPACITY TO SERVE ITS RETAIL CUSTOMERS?

A. No, it has not. Even after deducting the Scherer Unit 3 capacity not committed to Gulf's remaining wholesale unit power sales from its 2016 Ten-Year Site Plan, Gulf is not forecasting a need for any new capacity additions for its native load customers until June 2023 (Gulf 2016 Ten-Year Site Plan at 3). In addition, in response to

Citizens' Interrogatory No. 174, Gulf indicated it has not performed any analysis, nor had any analysis performed on its behalf, to evaluate utilizing Gulf's ownership share of Scherer Unit 3 to serve retail customers starting in 2016 versus other resource alternatives. Also, for a number of reasons, which I will address later in my direct testimony, Gulf claimed it was unnecessary for such an analysis to be performed.

Regardless, the lack of an analysis, combined with Gulf's statements and assumptions in its annual ten-year site plans from 2000 through 2015, clearly show that Gulf's intention to use its Scherer Unit 3 capacity to serve its retail customers is a very recent development -- not part of a plan that has existed for several years. Moreover, until recently, Gulf's publicly stated intention was to continue to dedicate Scherer Unit 3 to making wholesale unit power sales for the benefit of Gulf's stockholder(s) through at least 2024.

Q. IS THERE ADDITIONAL EVIDENCE SHOWING THIS WAS THE CASE?

A. Yes, there is. Gulf's responses to discovery in this proceeding show that, for at least five years, Gulf has been heavily focused on finding a new source of revenue for its share of Scherer Unit 3 capacity when its latest wholesale unit power sales contracts expire in December 2015, May 2016 and December 2019. In response to Staff's Interrogatory No. 65, Gulf indicated:

> Although the Company had diligently marketed the output of Scherer Unit 3 over the last five years, including responding to formal requests for proposals as well as providing unsolicited offers, it has been unable to find a buyer for the output of the unit.

Gulf, in response to Citizens' Interrogatory No. 130, further detailed its efforts to enter into new long-term contracts for Scherer Unit 3, or to make an asset sale for Scherer Unit 3.

In Citizens' Request for Production of Documents No. 96, Gulf was asked to provide any written studies, cost benefit analysis or evaluations conducted by or for Gulf with regard to its options for its Scherer Unit 3 upon termination of the wholesale unit power sales contracts in December 2015, May 2016 and December 2019. In response, Gulf provided for review a large number of presentations and other documents which include summaries of an extensive amount of analyses that were performed by or on behalf of Gulf, with respect to finding a revenue source for Gulf regarding Scherer Unit 3 upon termination of the wholesale unit power sales contracts in December 2015, May 2016 and December 2019.

From my review of those documents, it is clear Gulf was seeking the highest shareholder-benefitting revenue opportunity available for its Scherer Unit 3 capacity. Furthermore, Gulf's analyses did not examine whether Scherer Unit 3 was needed for Gulf's retail customers or whether Scherer Unit 3 was the most cost-effective resource choice for Gulf's retail customers. The analyses were instead focused on finding a new revenue source for Gulf for Scherer Unit 3. For example, in a **September 16, 2011 presentation titled "Gulf Power Scherer 3 Strategy Update," the focus of the presentation is on identifying potential off-takers for the Scherer Unit 3 capacity and on a pricing strategy to maximize revenues. As outlined on Slide 3 of that presentation, the capacity price guidance from Gulf was to seek a price of [redacted] per kW-month, but not to settle for a price of less than [redacted] per kW-month. In addition, on Slide 4 of that presentation, Gulf Power Retail is identified as one of the other possible off-takers of the Scherer Unit 3 capacity** (Gulf's response to Citizens' Request for Production of Documents No. 96 at 16186-OPC-POD-96-65 through 160186-OPC-POD-96-77).

Even more compelling are the slides from an undated presentation that was also included in the documents provided by Gulf. **In this other presentation, pricing strategies are again discussed. In addition, the sixth slide in it very clearly lays out how Gulf was considering its options. It was weighing marketing the Scherer Unit 3 capacity in the wholesale market at an estimated market price of [redacted] to [redacted] per kW/month, versus leaving Scherer Unit 3 in the Southern Company power pool with a [redacted] to [redacted] per kW/month value, versus pursuing retail rate basing the unit** (*Id.* at 160186-OPC-POD-96-183 through 160186-OPC-POD-96-191). To complete the puzzle, as I have indicated, for the test year in this proceeding, Gulf's proposal to bring 160 MW of Scherer Unit 3 into retail rates would effectively yield it revenues of $212 per kW-year or $17.67 per kW/month between base rates and its ECRC. Clearly, Gulf was not examining what is best for its retail customers; it was examining what was best for its shareholders.

C. Alleged Regulatory Compact for Scherer Unit 3

Q. MR. DEASON IN HIS TESTIMONY ALLEGES A REGULATORY COMPACT SHOULD APPLY TO GULF'S INVESTMENT IN SCHERER UNIT 3 BASED

ON THE CIRCUMSTANCES UNDER WHICH GULF MADE THAT INVESTMENT. HOW DO YOU RESPOND?

A. Based on my review of the relevant orders and transcripts, the scenario presented by Gulf to the Commission during informal workshops on October 9, 1978 (Docket No. 780714-EU) and on February 16, 1981 (undocketed), in which Gulf was supposedly "encouraged" by the Commission in Order No. 9628 in Docket No. 800001-EU, is not the one which Gulf has followed over the intervening 35 years. Any vestige of an informal regulatory compact between the Commission and Gulf that might have existed relating to Gulf's share of Scherer Unit 3 capacity has long been broken by the course of action Gulf actually chose to follow in the ensuing 35 years which followed.

Q PLEASE EXPLAIN THE SCENARIO THAT WAS PRESENTED BY GULF THOSE MANY YEARS AGO.

In the October 9, 1978 workshop, Gulf presented a scenario where it essentially would have to construct expensive capacity at its Caryville site (or elsewhere) if it did not pursue purchasing a portion of the Scherer generating units. Gulf was essentially asking the Commission to be able to recover cancellation costs for its Caryville project so that it could pursue its needed capacity at a much lower cost by purchasing a portion of the Scherer generation units (Mr. Deason's Exhibit No. JTD-2 at RC-93 through RC-103 RC-150). In addition, Gulf left the Commission at the time with the impression that Gulf had to act fairly quickly with respect to the Scherer opportunity (Id. at RC-149 through RC-150).

In Docket No. 800001-EU, Gulf sought actually to recover in rates its Caryville cancellation costs. In its Order No. 9628, the Commission allowed rate recovery of the cancellation costs subject to refund in the event the Scherer transaction was not consummated within one year, or the cancellation was not otherwise justified (Id. at RC-161 through RC-162 and RC-164 through RC-165). The Commission clearly expressed concern that the cancellation cost recovery had been justified by the proposed Scherer transaction to meet a Gulf capacity need at lower cost, but that in the two years since it first approached the Commission about the proposed transaction, Gulf had not acted upon it, potentially to the detriment of its retail customers.

In the February 16, 1981 informal workshop, Gulf updated its Scherer transaction scenario. Essentially, Gulf's load projection had fallen further to the point that if the Caryville capacity were to be constructed it would not be needed until 1993. As a result, pursuing the Scherer capacity in lieu of Caryville would provide the Scherer capacity to Gulf four to six years ahead of Gulf's need for that capacity for its retail customers. However, Gulf had identified an opportunity to sell at least a portion of the output of the Scherer capacity to other utilities until Gulf needed it for its retail customers, and Gulf expressed confidence that it could market the remaining capacity during that period of time as well. As a result, Gulf was seeking informal assurance from the Commission that it would be supportive of Gulf purchasing the out-of-state Scherer capacity even though the capacity would not initially be used by Gulf's retail customers. (Id. at RC-193, RC-194, RC-201 and RC-205). Very shortly thereafter, Gulf proceeded to sign a contract to acquire the Scherer capacity, and executed wholesale unit power sales for delivery through 1993. (Deason Direct at 12). Gulf was then permitted to recover its cancellation cost for Caryville, pursuant to Order No. 9628.

In summary, the scenario under which the alleged informal regulatory compact was made was one in which Scherer's capacity would be utilized to serve Gulf's retail customers within six years of entering service, not 29 years after entering service and not -- as it turned out -- only when Gulf could no longer find a better revenue opportunity for its shareholders in the wholesale market than the revenues it could earn under retail rates for the capacity. Gulf has only sought to serve its retail customers with its Scherer capacity when it has been unable to find better market opportunities for itself, and until now, excluded its share of Scherer Unit 3 from its resource planning for its native load customers by consistently forecasting a wholesale unit power sales obligation equal to its Scherer Unit 3 capacity out to the end of Gulf's ten-year planning horizon.

D. Recommended Regulatory Treatment for Scherer Unit 3

Q. HOW SHOULD THE COMMISSION TREAT ITS REVIEW OF GULF'S PROPOSAL TO BRING SCHERER UNIT 3 INTO RETAIL RATES?

A. In light of how Gulf has actually utilized and planned to utilize its Scherer Unit 3 capacity over the past 29 years to serve its own interest rather than that of its retail customers, I recommend the Commission review Gulf's proposal in the same manner it would review any other Gulf proposal to add a new capacity resource to serve retail customers. Specifically, in order to incorporate the unit into retail rates, Gulf would have needed to demonstrate that the assignment of the Scherer Unit 3 capacity to its retail customers is a prudent decision on behalf of its retail customers and that the capacity is used and useful in serving the needs of its retail customers. To that end, Gulf would have needed to demonstrate that it both needs the Scherer Unit 3 capacity, and that the Scherer Unit 3 capacity is its most cost-effective resource choice for providing reliable electric service to its retail customers. In its direct testimony, Gulf failed to meet its burden of proof on this issue.

III. NEED FOR AND COST-EFFECTIVENESS OF SCHERER UNIT 3

Q. DOES GULF CURRENTLY HAVE ANY NEED FOR ADDITIONAL GENERATION CAPACITY IN ORDER TO MEET ITS PLANNING RESERVE MARGIN TARGETS?

A. No, it does not. As I indicated earlier in my testimony, with or without the Scherer Unit 3 capacity that is not committed to its remaining wholesale unit power sales, Gulf's own projections show that it will not need additional capacity to meet its planning reserve margin target of 15% until 2023. Gulf presented its planning reserve margin forecast with and without the Scherer Unit 3 capacity by year in its response to Staff Interrogatory No. 64. Not utilizing its uncommitted Scherer Unit 3 capacity to serve what it characterizes as its native load customers will simply increase its forecasted capacity need in 2023 from 654 MW to 866 MW.[8]

[8] Page 89 of Gulf's 2016 Ten-Year Site Plan includes a new capacity addition of 654 MW in 2023 in order to maintain a target planning reserve margin of 15% with Gulf's uncommitted portion of Scherer Unit 3 assigned to native load customers. Removing the uncommitted Scherer Unit 3 capacity would increase the need by 212 MW from 654 MW to 866 MW.

Q. PUTTING ASIDE THAT GULF DOES NOT CURRENTLY NEED CAPACITY TO MEET ITS PLANNING RESERVE MARGIN TARGET, DOES GULF HAVE A NEED FOR ADDITIONAL BASE LOAD CAPACITY?

A. No, it does not. Gulf's FERC Form 1 filings for the past 25 years show that Gulf has been a significant net seller of energy at wholesale to the Southern power pool and to the remainder of the wholesale market. For example, in 2015, according to its FERC Form 1 filing, Gulf sold 2,631,518 MWh at wholesale on a non-requirements basis and purchased 1,916,617 MWh at wholesale (Gulf's 2015 FERC Form 1 at Page 401a). As a result, over the year as a whole, Gulf had net wholesale sales of 714,901 MWh. These levels of wholesale energy sales will not change even with Gulf's uncommitted share of Scherer Unit 3 assigned it its retail customers. Furthermore, on page 74 of Gulf's 2016 Ten-Year Site Plan, Gulf indicates that even after the expiration of its 885 MW Purchased Power Agreement ("PPA") with Shell, which is sourced from a combined cycle generation facility in Alabama, Gulf's capacity need in 2023 that will be driven by that expiration will be for peaking generation in the form of new combustion turbine generation – not new base load capacity.

Q. HAS GULF PERFORMED ANY ANALYSIS TO SHOW THAT ITS NATIVE LOAD CUSTOMERS HAVE A NEED FOR ITS SCHERER UNIT 3 CAPACITY THAT IS NOT COMMITTED TO ITS REMAINING WHOLESALE UNIT POWER SALES, OR THAT THIS CAPACITY IS THE MOST COST-EFFECTIVE RESOURCE ALTERNATIVE FOR ITS NATIVE LOAD CUSTOMERS?

A. No, it has not. As I noted earlier in my testimony, when asked in Citizens' Interrogatory No. 174 to provide any analysis that it has performed of this nature, Gulf indicated that it had not performed, nor had performed on its behalf, any such analysis. Gulf also indicated that it did not believe such an analysis was necessary for three reasons.

Q. WHAT WAS THE FIRST REASON GIVEN?

A. Gulf asserted that it is returning an existing resource to serve its customers consistent with the original purpose for which it was planned, acquired, and ultimately built, and is not evaluating it as a new resource versus other alternatives.

Q. HOW DO YOU RESPOND TO THIS ASSERTION?

A. This is essentially Gulf's informal regulatory compact argument. As I discussed earlier in my testimony, Gulf over the past 29 years has not utilized its Scherer Unit 3 capacity in a manner consistent with the scenario it presented to the Commission over 35 years ago. For 29 years (from the beginning of Scherer Unit 3's commercial operation), the capacity was devoted to providing profits for Gulf and Gulf is only now proposing to assign it to its retail customers because it cannot find a better revenue opportunity for itself in the wholesale market. Therefore, to the extent that any regulatory compact ever existed, it was broken by Gulf long ago. As I have recommended, the Commission should evaluate the proposed assignments of Gulf's Scherer Unit 3 capacity the same way that it would evaluate any other proposed new resource alternative.

Q. WHAT WAS THE SECOND REASON GIVEN BY GULF NOT TO PERFORM AN ANALYSIS?

A. Gulf believes any analysis, if performed, of operating Scherer Unit 3 post-2015 on behalf of its retail customers would show that it is decisively in the retail customers' best interest. Gulf also asserts that Scherer Unit 3 provides capacity value to Gulf Power, as well as energy value, as a resource dispatched on low variable cost Powder River Basin ("PRB") coal. Gulf goes on to indicate it believes those benefits would easily outweigh the costs to continue to operate Scherer Unit 3, given that it is already a well-controlled unit equipped with a baghouse, a selective catalytic reduction system ("SCR"), and a flue gas desulfurization system ("FGD").

Q. HOW DO YOU RESPOND TO THIS SECOND REASON?

A. There are two problems with this argument. First, Gulf would have the Commission only evaluate the value the Scherer Unit 3 capacity might provide against the operating and going forward capital costs of the facility. This ignores the depreciation expense and return on investment that Gulf's retail customers would have to pay through retail rates for the net book value of the capacity of Scherer Unit 3, which is approximately $1,200 per kW (Gulf's response to Citizens' Interrogatory No. 128), largely because of the SCR and FGD investments that Gulf made in the facility in the mid to late 2000s. In its 2016 Assumptions to the Annual Energy Outlook, the Energy Information Agency ("EIA"), has estimated the total overnight capital cost of a new advanced combined cycle generation facility to be only $1,060 per kW and that of a new advanced combustion turbine generation facility to be only $683 per kW (EIA 2016 Assumptions to the Annual Energy Outlook at page 108).

Second, coal-fired generation, even coal-fired generation burning PRB coal, is not the low cost source of energy it once was. As shown in Table JRD-1 earlier in my testimony, Gulf's FERC Form 1 filings report that the average fuel cost of Scherer Unit 3 has been over $28 per MWh from 2013 through 2015. SNL Financial reports that the average spot on-peak market price for energy for trading at Into Southern in 2016 was only $27.20 per MWh. The average around-the-clock market price for energy during this period, which would add in off-peak market prices for energy, was likely even lower. Furthermore, a new advanced combined cycle generation facility is estimated by the EIA to have a heat rate of 6,300 Btu/kWh (Id. at page 107). At that heat rate, natural gas prices would need to exceed $4.44 per MMBtu in order to cause the average fuel cost of a new advanced combined cycle generation facility to exceed $28 per MWh. Current Henry Hub forward annual strips for natural gas are all, as of January 6, 2017, trading below $3.85 per MMBtu for delivery through 2029.

Q. WHAT IS GULF'S THIRD REASON FOR NOT PERFORMING AN ANALYSIS?

A. Gulf believes Scherer Unit 3 provides other, non-quantifiable benefits, such as maintaining a diverse fuel supply, reducing fuel price volatility, providing a hedge against rising gas prices, and not contributing to greenhouse gas emissions in the state of Florida.

Q HOW DO YOU RESPOND TO THIS LAST ARGUMENT?

A Scherer Unit 3 may provide some of these benefits, but it does so at a premium versus other resource choices. The cost of that premium may not outweigh the benefits. This is another reason why a reasonable analysis of Scherer Unit 3 versus other resource options (including the option of not adding any new resources in light of the fact that Gulf does not currently have a capacity need until 2023 with or without the uncommitted Scherer Unit 3 capacity) should have been provided in order for Gulf to have met its burden to demonstrate whether Scherer Unit 3 is a cost-effective choice for Gulf's retail customers. Software tools like Strategist®, which Gulf already used in its integrated resource planning at the Southern electric system level, could have been utilized to examine these questions using probabilistic techniques. Gulf has failed to do so for its proposal for Scherer Unit 3.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO GULF'S REQUEST TO ASSIGN ITS UNCOMMITTED SCHERER UNIT 3 CAPACITY TO ITS RETAIL CUSTOMERS AND INCORPORATE THAT CAPACITY INTO GULF'S RETAIL RATES?

A I recommend that the Commission reject Gulf's proposal. Gulf's own Ten-Year Site Plan shows that Gulf's native load customers do not currently have a need for capacity until 2023, and even then it is for peaking generation, not for base load generation. In addition, Gulf has failed to meet its burden to produce an analysis in its direct case that reasonably shows that Scherer Unit 3 is the most cost-effective resource alternative available to Gulf to reliably serve its native load customers. Such alternatives would include one of adding no new resource at all, in addition to other resource alternatives, since Gulf's native load customers currently have no need for additional generation capacity.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

DIRECT TESTIMONY AND EXHIBITS

OF

ROXIE MCCULLAR

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 160186-EI

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roxie McCullar, CPA. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a licensed Certified Public Accountant in the state of Illinois. I am a member of the Society of Depreciation Professionals, the American Institute of Certified Accountants, and the Illinois CPA Society. I received my Master of Arts degree in Accounting from the

University of Illinois in Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal. Over the past 19 years I have filed testimony in over 50 state regulatory proceedings on cost allocation, universal service, and depreciation issues.

Q. HAVE YOU PREPARED AN APPENDIX THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown on the attached Appendix A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Florida's Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address certain depreciation related issues presented in Gulf Power Company's ("Gulf" or "Company") testimony and filings in this proceeding.

SUMMARY

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes. I recommend that:

(1) The depreciation rates shown on Exhibit RMM-1 be approved for Gulf Power;

(2) The Company should keep the Commission and other parties informed regarding the status of the negotiations of any possible contract extension for the Pace Plant.

DEFINITION OF DEPRECIATION

Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission ("FERC") definitions contained in FERC Uniform System of Accounts (18 CFR part 101 ("FERC USOA")) state:

> 12. *Depreciation,* as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1]

The FERC USOA definition of "depreciation" specifically states depreciation is a "loss in service value." FERC defines service value as "the difference between original cost and net salvage value of electric plant."[2]

Exhibit RMM-12 includes the FERC USOA sections referenced in this testimony.

Q. IS THIS THE SAME DEFINITION USED BY MR. WATSON AS STATED IN HIS TESTIMONY?

A. No. Contrary to the FERC USOA definition, Mr. Watson stated that under his definition depreciation is not a loss in value. He stated: "Depreciation is a process of allocation, not valuation."[3] Mr. Watson further explained: "the amount allocated to any one accounting

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[1] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. (18 CFR part 101).
[2] FERC USOA Definition 37 (18 CFR part 101).
[3] Page 5, line 20 of Watson Direct Testimony.

period does not necessarily represent an actual loss or decrease in value that will occur during that particular period."[4]

Q. IS MR. WATSON'S DEFINITION OF DEPRECIATION APPROPRIATE FOR THIS PROCEEDING?

A. No. Mr. Watson used the definition of "depreciation accounting," not "depreciation." In fact, he stated: "The term 'depreciation,' as used herein, is considered in the accounting sense…"[5]

Q. WHAT IS THE SIGNIFICANCE OF THE DIFFERENCE BETWEEN "DEPRECIATION" AND "DEPRECIATION ACCOUNTING"?

A. "Depreciation accounting," as defined by the American Institute of Certified Public Accountants ("AICPA") is used for purposes such as filings made under the jurisdiction of the Security Exchange Commission ("SEC"). "Allocation, not valuation" is part of the "depreciation accounting" definition used for those purposes.

However, in a utility regulatory proceeding such as this, where the depreciation expense impacts the rates charged to ratepayers, it is appropriate to calculate "depreciation" that is related to the service value consumed by the ratepayers in the course of service, as discussed in the FERC USOA definition.

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[4] Page 5, line 24 - page 6, line 1 of Watson Direct Testimony.
[5] Page 5, lines 17-18 of Watson Direct Testimony.

Q. DOES A STANDARD DEPRECIATION TEXT DISCUSS THE DIFFERENCE BETWEEN "DEPRECIATION" AND "DEPRECIATION ACCOUNTING"?

A. Yes. Page 14 of the text Public Utilities Depreciation Practices, when discussing the AICPA definition of depreciation accounting, states:

> This definition of depreciation accounting brings the 'allocation of cost' concept into much clearer focus. It de-emphasizes the concept of depreciation expense as a 'loss in service value' or an 'allowance' and emphasizes the concept of depreciation expense as the cost of an asset which is allocable to a particular accounting period.[6]

Exhibit RMM-11 includes the relevant pages from Public Utilities Depreciation Practices published by National Association of Regulatory Utility Commissioners ("NARUC") in 1996.

Q. WHAT DEFINITION OF DEPRECIATION DO YOU RELY ON IN THIS TESTIMONY?

A. Since this is a utility regulation proceeding, I rely on the FERC USOA definition of "depreciation" which focuses on the "loss of service value," unlike the definition of "depreciation accounting" relied on by Mr. Watson, which "is a process of allocation, not valuation."

In other words, depreciation, as discussed in this testimony, conforms to the FERC USOA definition.

[6] Page 14 of Public Utilities Depreciation Practices, published by National Association of Regulatory Utility Commissioners (NARUC), 1996.

CORRECTED SMITH CC RESERVE IN DEPRECIATION RATE STUDY

Q. DID YOU REVIEW THE COMPANY'S DEPRECIATION RATE STUDY AT DECEMBER 31, 2016?

A. Yes, I first began with a review of the Depreciation Rate Study at December 31, 2016, filed as Appendix A on July 14, 2016 in Docket No. 160170-EI. That study showed an increase of $23.4 million in annual depreciation accrual, based on December 31, 2016 plant in service amounts.[7] OPC's first round of discovery regarding the July 14, 2016 Depreciation Rate Study asked about an "overall negative book reserve for Smith CC" that was included in the Depreciation Rate Study. The Company's response stated:

> An error was made in the calculation of the book reserve for the Plant Smith Combined Cycle (Smith CC) in the Depreciation Study filed with the Florida Public Service Commission (FPSC) on July 14, 2016. A corrected Study was filed with the FPSC on September 20, 2016. The correction changed the book reserve for the Smith CC from a negative amount to a positive $31,407,661.[8]

Q. WHAT IMPACT DID THIS CORRECTION TO SMITH CC BOOK RESERVE HAVE ON THE PROPOSED ACCRUAL INCREASE?

A. The correction to the Smith CC book reserve decreased the proposed depreciation annual accrual by $2.9 million, based on December 31, 2016 plant in service amounts.[9] The corrected Depreciation Rate Study filed on September 20, 2016 showed an increase of $20.4 million in annual depreciation accrual, based on December 31, 2016 plant in service amounts.[10]

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[7] Page 123 of Appendix B of Company's July 14, 2016 filing in Docket No. 160170-EI.
[8] Gulf response to OPC ROG-10 in Docket No. 160170-EI.
[9] $20,414,266 from page 124 of corrected Appendix A of Company's July 14, 2016 filing in Docket No. 160170-EI less $23,387,345 from page 123 of Appendix A of Company's July 14, 2016 filing in Docket No. 160170-EI. ($20,414,266 - $23,387,345 = -$2,973,079).
[10] Page 124 of Appendix B of Company's September 20, 2016 filing in Docket No. 160170-EI.

The adjustments to the Depreciation Rate Study discussed in this testimony are to the Company's corrected Depreciation Rate Study filed on September 20, 2016 in Docket No. 160170-EI, and filed as Exhibit DAW-1 in Docket No. 160186-EI.

ACCOUNT 365 AVERAGE SERVICE LIFE

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE PROJECTION LIFE FOR ACCOUNT 365, OVERHEAD CONDUCTORS & DEVICES?

A. Yes, I recommend a 50-year life with a R0.5 curve for Account 365, Overhead Conductors & Devices.

Q. WHAT LIFE DID THE COMPANY PROPOSE FOR ACCOUNT 365, OVERHEAD CONDUCTORS & DEVICES?

A. The Company proposed a 45-year life with a R1 curve. Page 80 of the Depreciation Rate Study states:

> A longer life would not be unreasonable but should be stabilized going forward. The SPR-B analysis indicates a life as long as 50 in the top three ranked life and dispersion curve combinations. The 45 year life and an R1 dispersion curve is ranked in the top three across the bands and has fair CIs with excellent REIs.[11]

Q. WHAT IS MEANT BY "SPR-B" ANALYSIS IN THE ABOVE QUOTE?

A. The term Simulated Plant-Record Balances ("SPR-B") is defined by NARUC as follows:

> A trial-and-error model used to estimate the average service life of a depreciable group. The SPR model simulates retirements and the resultant plant balances for combinations of standardized survivor curves and

[11] Page 80, Exhibit DAW-1 (Depreciation Rate Study).

average service lives and compares the results to the historical data until a good match is found.[12]

The "closeness of fit between calculated and actual balances in the Simulated Plant-Record Model" is measured by the conformance index ("CI").[13] The higher the CI the better the fit of the curve.

The retirement experience index ("REI") "is the percentage of installations from the oldest vintage that would have retired by the end of the most recent year in the chosen band of years if the installations retired according to the specified survivor curve. The higher the REI the more assurance that a unique retirement pattern was used in the SPR simulation."[14]

Q. HOW ARE THE CI AND REI INTERPRETED IN CONSIDERING THE CLOSENESS OF FIT FOR THE RESULTS OF THE SPR-B ANALYSIS?

A. Mr. Alex E. Bauhan, the author of the SPR-Balances method proposed the following rankings of CIs.[15]

CI	Value
over 75	excellent
50 to 75	good
25 to 50	fair
under 25	poor

In the discussion of the SPR method, NARUC points out that:

[12] Page 325, Public Utilities Depreciation Practices, published by NARUC, 1996.
[13] Page 317, Public Utilities Depreciation Practices, published by NARUC, 1996.
[14] Page 324, Public Utilities Depreciation Practices, published by NARUC, 1996.
[15] Page 96, Public Utilities Depreciation Practices, published by NARUC, 1996.

> Bauhan states that the CI should be 'good' or better (i.e., at least 50) in order for a life determination to be considered entirely satisfactory.[16]

and

> According to Bauhan, results with an REI less than 'fair' (i.e., less than 33%) should be discarded regardless of the CI.[17]

Q. PAGE 80 OF THE DEPRECIATION RATE STUDY QUOTED ABOVE REFERENCES THE TOP THREE FITS ACROSS THE BANDS. IS YOUR RECOMMENDED 50-YEAR R0.5 CURVE IN THE TOP THREE FITS?

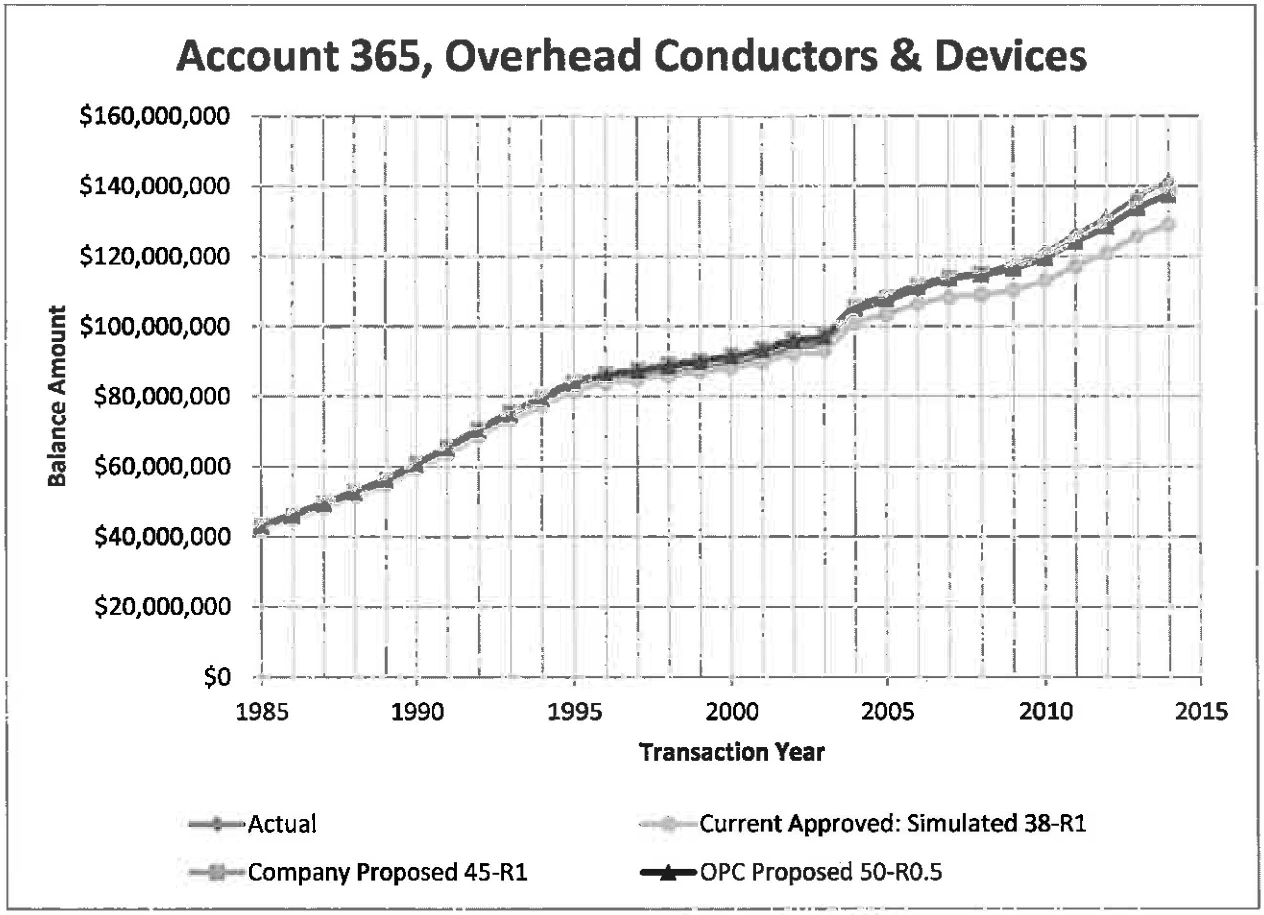
A. Yes, my recommended 50-year R0.5 curve is in the top three fits.

The average service life of the top three fits are 45-years, 50-year, and 55-years. The Company's proposed 45-year is at the bottom of the range. My recommended 50-year life is in the middle of the range.

Based on the analysis and review of the information provided in this proceeding, I recommend a 50-year R0.5 curve for Account 365. Exhibit RMM-3 shows the calculation of the average remaining life using the 50-year R0.5 curve

[16] Page 99, Public Utilities Depreciation Practices, published by NARUC, 1996.
[17] Page 99, Public Utilities Depreciation Practices, published by NARUC, 1996.

Below is a graph of the actual balances and the simulated balances produced by the Company's proposed and my recommended life and curves.



<u>ACCOUNT 369.1 AVERAGE SERVICE LIFE</u>

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE PROJECTION LIFE FOR ACCOUNT 369.1, OVERHEAD SERVICES?

A. Yes, I recommend a 46-year life with a R0.5 curve for Account 369.1, Overhead Services.

Q. WHAT LIFE DID THE COMPANY PROPOSE FOR ACCOUNT 369.1, OVERHEAD SERVICES?

A. The Company proposed a 42-year life with a R1 curve. Page 87 of the Depreciation Rate Study states:

> Discussions with Company personnel indicate load and relocations are the primary drivers of retirement for overhead services. The SPR-B analysis shows the top ranked curves have poor to fair CIs but excellent REIs across the bands analyzed. The 42-year life expectancy and an R1 dispersion curve is in the top three ranked curves[18]

Q. PAGE 87 OF THE DEPRECIATION RATE STUDY QUOTED ABOVE REFERENCES THE TOP THREE FITS ACROSS THE BANDS. IS YOUR RECOMMENDED 46-YEAR R0.5 CURVE IN THE TOP THREE FITS?

A. Yes, my recommended 46-year R0.5 curve is in the top three fits.

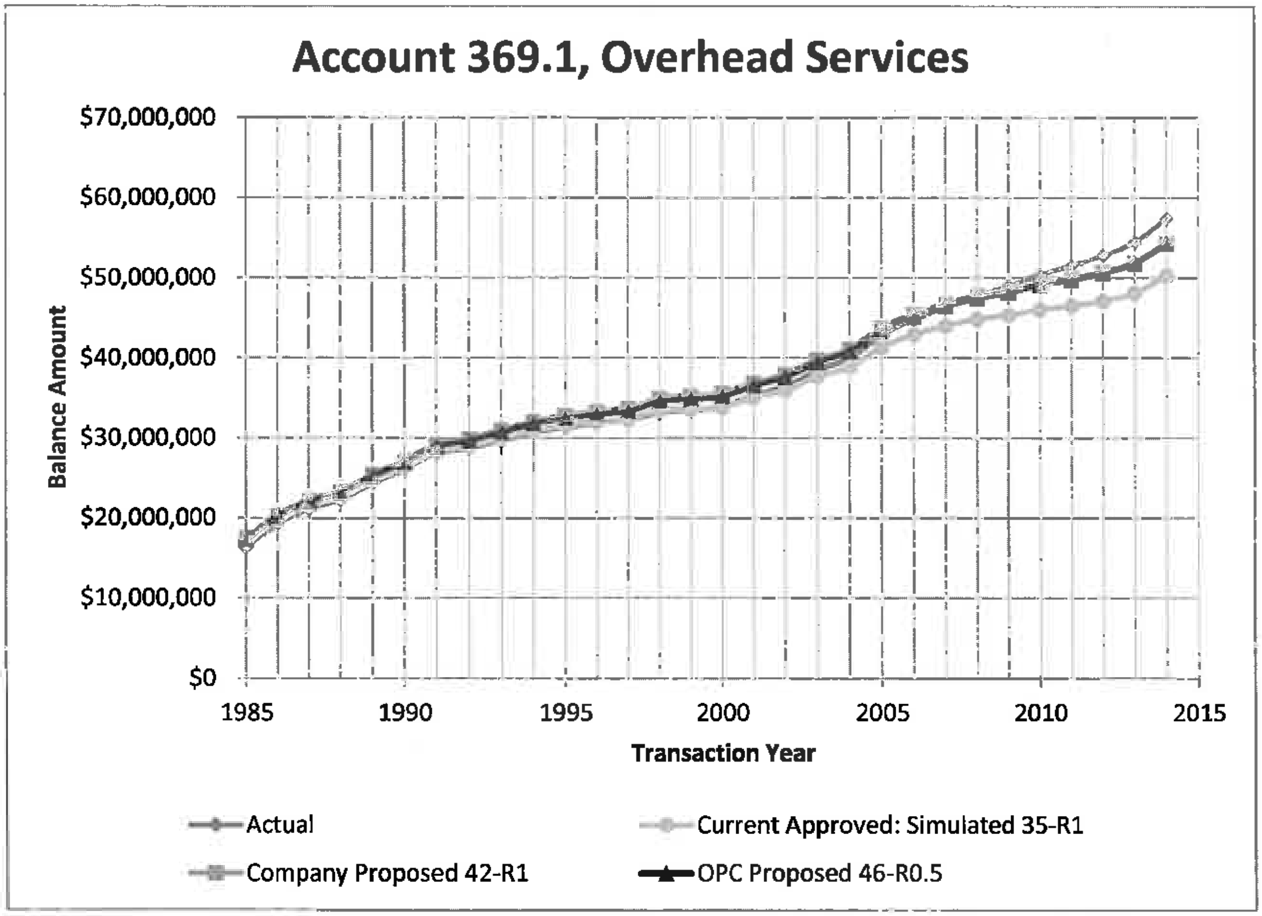
The average service life of the top three fits are 42-years, 46-years, and 51-years. The Company's proposed 42-year is at the bottom of the range. My recommended 46-year life is in the middle of the range.

Based on the analysis and review of the information provided in this proceeding, I recommend a 46-year R0.5 curve for Account 369.1.

Exhibit RMM-4 shows the calculation of the average remaining life using the 46-year R0.5 curve.

[18] Page 87, Exhibit DAW-1 (Depreciation Rate Study).

Below is a graph of the actual balances and the simulated balances produced by the Company's proposed and my recommended life and curves.



PRODUCTION PLANT INTERIM RETIREMENT RATIOS

Q. DO YOU HAVE ANY RECOMMENDATION REGARDING THE COMPANY'S PROPOSED INTERIM RETIREMENT RATIOS?

A. Yes. The Company's calculation of the interim retirement ratios ("IRR") for Account 312, Boiler Plant Equipment, Account 314, Turbogenerator Equipment, and Account 315, Accessory Electric Equipment included final retirement amounts.

I recommend a 0.73% IRR for Account 312, Boiler Plant Equipment, a 0.93% IRR for Account 314, Turbogenerator Equipment, and a 0.50% IRR for Account 315, Accessory Electric Equipment.

Q. PLEASE EXPLAIN WHAT IS MEANT BY AN IRR ESTIMATE.

A. The IRR is "the ratio of the interim dollars retired from a group during a period divided by the total dollars in service at the beginning of the period." [19] An interim retirement is defined as follows:

> As used in life span analysis, retirements of component parts of a major structure prior to the complete removal of the retirement unit from service.[20]

The IRR estimates the retirement pattern of the components of the structure before the final retirement of the structure. For example, a roof often does not last the entire life of a building, so the retirement of the roof when a new roof is installed and the building will continue to be in service would be considered an interim retirement. However, the final retirement of the building, and any roof on the building at the time, is considered a final retirement. In the life span analysis, the final retirement is the date when the entire structure and components will retire at once.

The inclusion of a final retirement in the calculation of the IRR is incorrect. The final retirements are separately included in the depreciation rate calculation in addition to the IRR.

[19] Page 321, Public Utilities Depreciation Practices, published by NARUC, 1996.
[20] Page 321, Public Utilities Depreciation Practices, published by NARUC, 1996.

NARUC states:

> the interim retirement life table … may be developed by subtracting final retirements from total booked retirements[21]

NARUC also states:

> When developing the survivor curve for the life span group properties, however, final retirements are not included.[22]

Q. WHAT FINAL RETIREMENTS DID THE COMPANY INCLUDE IN THE CALCULATION OF THE IRR FOR ACCOUNT 312, BOILER PLANT EQUIPMENT, ACCOUNT 314, TURBOGENERATOR EQUIPMENT, AND ACCOUNT 315, ACCESSORY ELECTRIC EQUIPMENT?

A. In discovery, the Company stated that the final retirement amounts for Plant Crist Units 1-3 were included in the IRR calculations for Account 312, 314, and 315.[23] The following is the table of final retirements included in the IRR calculations.[24]

Units	Year	Account 312 ($)	Account 314 ($)	Account 315 ($)	Total ($)
Plant Crist Unit 1	2003	975,843	919,271	286,398	2,181,512
Plant Crist Unit 2	2006	1,171,365	1,363,687	222,550	2,757,602
Plant Crist Unit 3	2006	2,036,536	3,349,254	345,675	5,731,465
Total Plant Crist		**4,183,744**	**5,632,212**	**854,623**	**10,670,579**

Since the Company analyzes the interim retirements from 2005-2014 to estimate the IRR, the amounts of final retirements for Plant Crist Unit 1 in 2003 do not impact the

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[21] Page 148, Public Utilities Depreciation Practices, published by NARUC, 1996.
[22] Page 146, Public Utilities Depreciation Practices, published by NARUC, 1996.
[23] Gulf response to OPC ROG-141 (Docket No. 160186) and OPC ROG-17 (Docket No. 160170).
[24] Gulf response to OPC ROG-141 (Docket No. 160186).

Company's recommended IRR.[25] However, the final retirements in 2006 of Plant Crist Units 2 and 3 are improperly included in the Company's IRR calculations.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATED THE IRR.

A. Attached as Exhibit RMM-5 are pages 136-138 of Exhibit DAW-1, which show the calculation of the IRR for Accounts 312, 314, and 315

Looking at Account 314 on page 137 of Exhibit DAW-1, in the middle of the page, the "IRR" is shown as 1.0791%. This is calculated by dividing the "Average Retirement" of $3,356,509 by the "PIS" of $311,048,014. The PIS is the Plant in Service balance in account 314 at December 31, 2014. The Average Retirement is the average of the retirements shown for the 10-year period 2005-2014, as shown below.

Year	Retirement
2005	218,391
2006	6,909,778
2007	4,410,652
2008	1,141,101
2009	838,520
2010	6,249,585
2011	2,304,259
2012	8,935,933
2013	1,158,638
2014	1,398,230
Total Retirement	33,565,086
Average Retirement	3,356,509
2014 PIS	311,048,014
IRR	1.0791%

[25] Pages 41-42, Exhibit DAW-1 (Depreciation Rate Study).

Based on this calculation, the Company proposes a 1.08% IRR for Account 314.[26]

Q. WHAT IRR RESULTS FROM THE PROPER EXCLUSION OF FINAL RETIREMENT AMOUNTS IN THE CALCULATION OF THE INTERIM RETIREMENT PATTERN?

A. As shown in the response quoted above for Account 314, the Company's IRR calculation includes the final retirement amount of $1,363,687 for Crist Unit 2 in 2006 and $3,349,254 for Crist unit 3 in 2006.[27] This is a total of $4,712,941 final retirements included in 2006. Below is the calculation of the IRR that excludes the final retirement amounts in 2006.

Year	Retirement	Final Retirement	Adjusted
2005	218,391		218,391
2006	6,909,778	4,712,941	2,196,837
2007	4,410,652		4,410,652
2008	1,141,101		1,141,101
2009	838,520		838,520
2010	6,249,585		6,249,585
2011	2,304,259		2,304,259
2012	8,935,933		8,935,933
2013	1,158,638		1,158,638
2014	1,398,230		1,398,230
Total Retirement	33,565,086		28,852,145
Average Retirement	3,356,509		2,885,214
2014 PIS	311,048,014		311,048,014
IRR	1.0791%		0.9276%

As shown in the above table, the corrected IRR is 0.93% for Account 314.

[26] Page 42, Exhibit DAW-1 (Depreciation Rate Study).
[27] Gulf response to OPC ROG-141 (Docket No. 160186).

Q. WHAT IS EXHIBIT RMM-6?

A. Attached as Exhibit RMM-6 is the corrected IRR calculation for Accounts 312, 314, and 315.

I recommend a 0.73% IRR for Account 312, Boiler Plant Equipment, a 0.93% IRR for Account 314, Turbogenerator Equipment, and a 0.50% IRR for Account 315, Accessory Electric Equipment.

<u>Account 390 Future Net Salvage</u>

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S PROPOSED FUTURE NET SALVAGE PERCENT FOR ACCOUNT 390, STRUCTURES AND IMPROVEMENTS?

A. Yes. I am recommending a 0% future net salvage percent for Account 390, compared to the Company's proposed -5% future net salvage percent for this account.

Q. PLEASE EXPLAIN WHAT IS MEANT BY NET SALVAGE.

A. Net salvage is defined as "the salvage value of property retired, less the cost of removal."[28] Salvage value is defined as "the amount received for property retired, less any expenses incurred in connection with the sale or in preparing the property for sale; ..."[29] Cost of removal is defined as "the cost of demolishing, dismantling, tearing down or otherwise

[28] Definition 19 of FERC USOA (18 CFR part 101).
[29] Definition 35 of FERC USOA (18 CFR part 101).

removing electric plant, including the cost of transportation and handling incidental thereto."[30]

Q. WHAT IMPACT DOES NET SALVAGE HAVE ON DEPRECIATION RATES?

A. Positive net salvage results in a lower depreciation rate, everything else equal. Negative net salvage results in a higher depreciation rate, everything else equal.

As stated in NARUC's Public Utilities Depreciation Practices:

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage.[31]

In calculating the depreciation rates, it is necessary to estimate future net salvage, which is an estimate of what the net salvage will be when the investment now in service retires in the future.

Q. PLEASE EXPLAIN THE COMPANY'S SUPPORT FOR THE PROPOSED -5% FUTURE NET SALVAGE FOR ACCOUNT 390.

A. According to the Company, the Depreciation Rate Study "conservatively recommends retention of negative 5 percent net salvage for this account."[32] The Depreciation Rate Study indicates that the -5% is a "conservative" recommendation because "[i]n the most recent

[30] Definition 10 of FERC USOA (18 CFR part 101).
[31] Page 18, Public Utilities Depreciation Practices, published by NARUC, 1996.
[32] Pages 98-99, Exhibit DAW-1 (Depreciation Rate Study).

bands, the five-year and 10-year averages show negative 17.99 and negative 7.74 percent net salvage, respectively."[33]

The -17.99% and -7.74% historical net salvage amounts referenced in the Depreciation Rate Study can be found in the net salvage analysis included on page 157 of Exhibit DAW-1. The relevant page is attached as page 4, Exhibit RMM-7 to this testimony

Q. DO YOU AGREE WITH THE HISTORIC NET SALVAGE AVERAGE RELIED ON BY THE COMPANY IN THE DEPRECIATION RATE STUDY?

A. No. The historic net salvage analysis for Account 390 excludes gross salvage received from the retirement of one of the assets included in the account.

Page 4 of Exhibit RMM-7 shows a retirement in 2008 of $5,822,914 in account 390. In discovery, the Company stated that $5,641,104 of this $5,822,914 retirement in 2008 was "related to the sale of the Pace Boulevard office building in Pensacola."[34] Additionally in discovery, the Company stated that it received $4,297,789 for the sale of the Pace Boulevard office building.[35] The Company credited $1,445,879 of this $4,297,789 amount received to Account 108, Accumulated Provision for Depreciation and the remaining $2,851,910 to account 421.1, Gain on Disposition of Property.[36]

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[33] Page 98, Exhibit DAW-1 (Depreciation Rate Study).
[34] Gulf response to OPC ROG-23 (Docket No. 160170-EI).
[35] Gulf response to OPC ROG-24 (Docket No. 160170-EI).
[36] Gulf responses to OPC ROG-162 and 166.

Q. WHAT IS YOUR UNDERSTANDING OF THE FLORIDA PUBLIC SERVICE COMMISSION'S PREVIOUS RULINGS REGARDING THE GAIN ON A SALE OF UTILITY PROPERTY?

A. It is my understanding that the Commission's policy is to amortize the gain over a five-year period. The Commission stated in Order No. 13537:

> We have addressed the issue of the actual sale of Utility property in FPL's last full rate case and in a number of other rate cases. In those cases, we determined that gains or losses on the disposition of property devoted to, or formerly devoted to, public service should be recognized above the line and that those gains or losses, if prudent, should be amortized over a five-year period. We reaffirm our existing policy on this issue.[37]

Q. HAVE YOU BEEN ABLE TO CONFIRM THAT THE $2,851,910 BOOKED TO ACCOUNT 421.1, GAIN ON DISPOSITION OF PROPERTY WAS AMORTIZED ABOVE THE LINE OVER A FIVE YEAR PERIOD?

A. No. Regarding the $2,851,910 gain, the Company stated in response to discovery:

> Since the asset that was sold was being recovered in retail rates, the gain on the sale of the building was credited back to Gulf's retail customers in October 2008.[38]

I reviewed the Company's filing in a previous case, Docket No. 110138-EI. The Company's Schedule C-29 in that previous case shows the $2,852,000 gain in 2008, but I was unable to confirm that any amortization of that gain was included in the Company's

[37] Order No. 13537, issued July 24, 1984, in Docket No. 830465-EI. Also, see Order No. PSC-07-0913-PAA-GU, issued November 13, 2007, in Docket No. 060657-GU.
[38] Gulf response to OPC ROG-163(c).

requested revenue requirement for the projected 2012 test year. The Company's Schedule C-29 from Docket No. 110138-EI is attached as Exhibit RMM-8.

I also reviewed the Company's FERC Form 1 for the year 2008. Page 117, line 40 shows $0 in Account 421.1 in the year 2008. However, Page 450.1 does indicate that $1,445,879 was credited to Account 108 in 2008. Exhibit RMM-9 includes the referenced pages from the Company's 2008 FERC Form 1

Since the $2,851,910 gain should have been returned to the Company's ratepayers, OPC has issued discovery regarding how "the gain on the sale of the building was credited back to Gulf's retail customers."[39] As of the filing of this testimony, OPC has not received responses to those discovery requests. I reserve the right to supplement or modify my testimony based on my review of the outstanding discovery on this issue.

Q. WHAT AMOUNTS ARE PROPERLY INCLUDED IN ACCOUNT 108, ACCUMULATED PROVISION FOR DEPRECIATION?

A. FERC's USOA states:

> 108 Accumulated provision for depreciation of electric utility plant.
> A. This account shall be credited with the following:
> (1) Amounts charged to account 403, Depreciation Expense, or to clearing accounts for current depreciation expense for electric plant in service.
> ...
> B. At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of

[39] OPC ROG-189 and 190.

removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.[40]

In other words, the depreciation expense and the gross salvage go into the depreciation reserve ("credit") while the cost of removal and an amount equal to the investment that retires are taken out of the depreciation reserve ("debit").[41]

Q. DID THE COMPANY INCLUDE THE $1,445,879 CREDITED TO ACCOUNT 108, ACCUMULATED PROVISION FOR DEPRECIATION AS SALVAGE IN ITS HISTORIC SALVAGE ANALYSIS?

A. No. As stated in the FERC USOA, Account 108 "shall be credited with the salvage value and any other amounts recovered." The $1,445,879 credited to Account 108 was part of the amount recovered from the retirement and sale of the Pace Boulevard office building, which is salvage. As stated above, FERC USOA states that salvage is "the amount received for property retired …"[42]

Q. Please explain how the Company's exclusion of the $1,445,879 as salvage impacts the depreciation rate calculation for Account 390.

A. Understating the historic salvage can result in the understatement of the future salvage because the historic past salvage is reviewed when estimating the future salvage.

[40] FERC USOA (18 CFR part 101).
[41] See description of account 108 parts (A) and (B) in 18 CFR 201-Uniform System of Accounts (USOA).
[42] Definition 35, FERC USOA (18 CFR part 101).

The receipts from the sale of the building the Company credited to Account 108 is properly recognized as salvage in Account 108, as stated in FERC USOA.

The Company estimated the future net salvage amount partially based on the historic net salvage analysis that excluded the recognition of the salvage received for the sale of the Pace Boulevard office building.[43]

Q. WHAT WERE THE HISTORIC NET SALVAGE PERCENTS AS DETERMINED BY THE COMPANY, EXCLUDING THE $1,445,879 SALVAGE?

A. Excluding the $1,445,879 salvage from the historical net salvage analysis results in a 10-year average of a -7.74% and an overall 34-year average of -8.76%.[44]

Q. WHAT ARE THE HISTORIC NET SALVAGE PERCENTS WHEN THE GROSS SALVAGE RECEIVED FROM THE SALE OF THE PACE BOULEVARD OFFICE BUILDING ARE INCLUDED IN THE ANALYSIS?

A. Attached as Exhibit RMM-10 is the historic net salvage analysis for Account 390, including the salvage of $1,445,879 received in 2008 for the sale of the Pace Boulevard office building and credited to Account 108.

As is shown on this Exhibit RMM-10 the 10-year average is a +9.87% and the overall 34-year average is +2.13%.[45]

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[43] Page 98, Exhibit DAW-1 (Depreciation Rate Study).
[44] Page 156, Exhibit DAW-1, Appendix E-2 (Depreciation Rate Study) and Depreciation Rate Study work papers provided in response to OPC POD-4 in Docket No. 160170.
[45] The 5-year average still shows a -17.99% since the 2008 year would not be included in that average.

The historic net salvage averages that include more years of data are more representative of the future expectations since the Company is proposing an average service life of 46 years for this account.

Based on the expected life of this account, the trend of the historic net salvage with the inclusion of the proceeds from the sale of an asset in 2008, and review of the information provided in this proceeding, I recommend a 0% future net salvage ratio for Account 390.

Q. IS THE FUTURE NET SALVAGE PERCENT THE ONLY DIFFERENCE BETWEEN YOUR RECOMMENDED DEPRECIATION RATE AND THE COMPANY'S PROPOSED DEPRECIATION RATE FOR ACCOUNT 390?

A. No. I also correct what appears to be a typographical error. The Company's depreciation rate was calculated using a 30.7 average remaining life, which appears to be calculated using a 45-year average service life, instead of the Company-proposed 46-year average service life. Based on the Company's recommended average service life of 46 years and the R1.5 curve shape, the average remaining life is 31.66 years. I used the 31.66 years remaining life in the calculation of my recommended depreciation rate for this account.[46]

[46] I am not recommending a change in the Company's proposed average service life or survivor curve.

RETIREMENT YEAR OF PACE PLANT

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE COMPANY'S PROPOSED RETIREMENT YEAR OF 2018 FOR THE PACE PLANT (PEA RIDGE)?

A. Yes. The Company is recommending a 2018 retirement year for Pace Plant, due to the end of the current contract. In response to discovery, the Company indicated that it is still in negotiations regarding the possible extension of the contract for the Pace (Pea Ridge) site.[47]

I recommend that the Company inform the Commission regarding the status of the negotiations, and review the Company's proposed retirement year based on any possible contract extension. I further recommend that the Company adjust the depreciation rate to recognize any change in the retirement date.

DISMANTLEMENT STUDY

Q. DID YOU REVIEW THE COMPANY'S TESTIMONY REGARDING THE 2016 DISMANTLEMENT STUDY?

A. Yes, I did review the 2016 Dismantlement Study filed as Appendix B on July 14, 2016 in Docket No. 160170-EI and as Exhibit JJH-1, Schedule 6 in Docket No. 160186-EI.

It is my understanding that since the Dismantlement Study shows a "surplus in the accumulated dismantlement reserves," the Company is proposing to offset that surplus

[47] Gulf response to OPC ROG-9 and ROG-20 (Docket No. 160170).

with the $62.5 million Other Cost of Removal regulatory asset established in the Settlement Agreement in Docket No. 130140-EI.[48]

Therefore, the Company is not including any recovery of its estimated future dismantlement costs in this proceeding.

I am not recommending any adjustments to the Company's Dismantlement Study.

IMPACT ON THE COMPANY'S FILED REVENUE REQUIREMENT

Q. What adjustment did the Company make to depreciation expense based on its proposed change to the depreciation rates?

A. Adjustment 43 in the Company's calculated revenue requirement shows a $7,291,000 increase in expense due to the Depreciation Rate Study and Dismantlement Study based on the Company's projected December 31, 2017 test year.[49]

The adjustments I made to the proposed depreciation rates, as discussed in this testimony, reduce the Company's adjustment 43 by $1,556,000. This reduction is shown on Exhibit RMM-2, and was provided to OPC Witness Donna Ramas.

[48] Pages 18-19 of Hodnett Direct Testimony.
[49] The depreciation rates and accrual amounts shown in Exhibit RMM-1 are based on December 31, 2016 plant in service amounts.

Q. WHAT IS EXHIBIT RMM-13?

A. Exhibit RMM-13 consists of copies of discovery responses referenced in my testimony and exhibits.

<u>CONCLUSION</u>

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. For the reasons stated above, I recommend that:

(1) The depreciation rates shown on Exhibits RMM-1 be approved for Gulf Power;

(2) The Company keep the Commission and other parties informed regarding the status of the negotiations of any possible contract extension for the Pace Plant.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DIRECT TESTIMONY

OF

DONNA RAMAS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 160186-EI

INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission ("PSC" or "Commission") on several prior occasions. I have also testified before many other state regulatory commissions.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit DMR-1, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Citizens of the State of Florida ("Citizens") for the Office of Public Counsel ("OPC").

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

A. I am presenting OPC's overall recommended revenue requirement for Gulf Power Company ("Gulf" or "Company") in this case. I also sponsor several adjustments to the Company's proposed rate base and operating income.

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

A. Yes. Jim Dauphinais presents Citizens' recommendations regarding Scherer Unit 3 and Roxie McCullar presents Citizens' recommendations on depreciation and dismantlement. Dr. Randall Woolridge presents Citizens' recommended capital structure, capital cost rates and overall rate of return.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I first present the overall financial summary for the base rate change, showing the revenue requirement recommended by Citizens. This is based on Dr. Woolridge's capital structure and rate of return recommendation, the adjustments sponsored in this testimony, and the adjustments sponsored by Mr. Dauphinais and Ms. McCullar. I then provide a brief overview of the basis of the Company's projected test year and address some concerns with the Company's budget and forecast timing that are specific to this proceeding. Finally, I present my proposed adjustments which impact the test year revenue requirements. Exhibit DMR-2 presents the schedules and calculations in support of this testimony. Exhibit DMR-3 consists of copies of discovery responses referenced in this testimony.[1]

OVERALL FINANCIAL SUMMARY

Q. PLEASE DISCUSS THE EXHIBIT YOU PREPARED IN SUPPORT OF YOUR TESTIMONY.

A. Exhibit DMR-2, totaling 19 pages, consists of Schedules A-1, B-1 through B-4, C-1 through C-12, and D.

Schedule A-1 presents the revenue requirement calculation, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the recommendations made by Citizens' witnesses Dauphinais, McCullar and Woolridge. Schedule B-1 presents OPC's adjusted rate base and Schedule B-2 identifies each of the adjustments impacting rate base recommended by OPC in this case. Schedules B-3 through B-4 provide supporting calculations for several of the rate base adjustments addressed in this testimony. OPC's adjusted net operating income is presented on Schedule C-1, and the recommended net operating income adjustments are identified on Schedule C-2.

[1] For several of the voluminous POD responses provided by Gulf, only the portions of the response referenced in this testimony are provided in Exhibit DMR-3.

Schedules C-3 through C-12 provide supporting calculations for the adjustments to net operating income I sponsor.

Q. WOULD YOU PLEASE DISCUSS SCHEDULE D?

A. Schedule D presents Citizens' recommended capital structure and overall rate of return, based on the revisions to Gulf's proposed capital structure recommended by Dr. Woolridge and the rate of return on equity and debt rates recommended by Dr. Woolridge. The capital structure ratios are based on the ratios recommended by Dr. Woolridge; however, the capital structure dollar amounts differ from his recommendations only to the extent that I applied the pro rata adjustments to the capital structure that are needed to synchronize Citizens' recommended rate base with Dr. Woolridge's recommended capital structure. As presented in Dr. Woolridge's testimony and shown on Schedule D, OPC's recommended overall rate of return is 5.09%.

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

A. As shown on Exhibit DMR-2, Schedule A-1, OPC's recommended adjustments in this case result in a revenue decrease for Gulf Power Company, on a Florida jurisdictional basis, of $2,087,000. This is $108,869,000 less than the $106,782,000 base rate increase requested by Gulf in its filing. While OPC's recommended adjustments result in a $2,087,000 revenue decrease, additional adjustments to Gulf's revenue requirement may be appropriate. The adjustments recommended by OPC's witnesses to date in this proceeding are based on the amount of analysis conducted in the timeframe allowed for in the procedural schedule in this case.

Q. OPC WITNESS JIM DAUPHINAIS RECOMMENDS THAT SCHERER UNIT 3 BE EXCLUDED FROM GULF'S REVENUE REQUIREMENTS. HAVE YOU REFLECTED THE IMPACT OF THIS RECOMMENDATION IN YOUR EXHIBIT?

A. Yes. On Exhibit DMR-2, Schedules B-2 and C-2, I included the adjustments that are needed to remove Scherer Unit 3 from the revenue requirements in this case, consistent with Mr. Dauphinais' recommendation. The amounts included in Gulf's 2017 adjusted test year for Scherer Unit 3 were provided by the Company in response to Citizens' Interrogatory 124. The Scherer Unit 3 adjustments in Exhibit DMR-2, Schedule C-2 include the removal of $3,846,000 of Other Operating Revenues that the Company has identified in response to Citizens' Interrogatory 124 as "FERC Account 447 – Sales to Non-Associated Companies." The impact on revenue requirement associated with the Company's proposed treatment of Scherer Unit 3 that is identified on page 15 of Gulf Witness Xia Liu's testimony does not include the offsetting impact of the $3,846,000 of Other Operating Revenues. Pending responses to outstanding discovery on this issue, I have removed the $3,846,000 of Other Operating Revenues on Schedule C-2 at this time.

<u>BASIS OF PROJECTED TEST YEAR</u>

Q. WHAT PERIOD DID GULF USE FOR THE TEST YEAR IN THIS CASE AND WHAT IS THE BASIS OF THE TEST YEAR?

A. The Company's adjusted revenue requirements are based on a projected test year ending December 31, 2017. In its planning and budgeting process, the Company produces an annual budget and a budget forecast for four subsequent years. Gulf's 2016 Budget and Forecast, consisting of budget year 2016 and forecast years 2017 through 2020, is the basis for the projected amounts incorporated in Gulf's projected 2017 test year. Thus, the projected 2017 test year is based on amounts incorporated in the 2016 Budget and Forecast.

Q. WHEN DID THE COMPANY BEGIN PREPARING THE 2016 BUDGET AND FORECAST?

A. An initial step of the budgeting process is the Budget Message that is issued by Gulf's Chief Financial Officer (CFO), Xia Liu, to the Planning Units. The 2016 Budget Message was issued by Ms. Liu on July 8, 2015,[2] which is over 18 months ago. Included as an attachment to the 2016 Budget Message were O&M and capital budget guidelines for the Planning Units to reference in preparing their 2016 budget and forecast. The final approved 2016 O&M and capital budgets for 2016 and the final 2017 through 2020 forecasts were distributed from Ms. Liu on February 3, 2016,[3] almost a year ago.

Q. GIVEN THE AMOUNT OF TIME THAT HAS PASSED SINCE THE 2016 BUDGET AND FORECAST WAS PREPARED, HAS A MORE RECENT FINAL BUDGET BEEN PROVIDED?

A. No, apparently not as of the date this testimony was prepared. The Company was requested to provide a more recent version of Gulf's projected monthly income statement, balance

[2] Response to Citizens' POD 8.
[3] Response to Citizens' POD 17.

sheet and utility plant balances for the period December 2016 through December 2017 than the versions provided as exhibits to Gulf witness Mason's testimony upon which the 2017 projected test year is based, if more recent versions are available. In response, the Company indicated that "There are no responsive documents for this request."[4] Thus, as of the date this testimony was prepared, the Company had not provided an update to the 2017 forecasts from the amounts presented in its 2016 Budget and Forecast.

Q. HAVE YOU REVIEWED THE ACCURACY OF THE 2016 BUDGET AND FORECAST BASED ON RECENT ACTUAL INFORMATION?

A. Yes, to the degree I was able to based on information provided by the Company. In response to Citizens' POD 19, the Company provided the quarterly O&M budget variance reports for the period December 2014 through June 2016. The report for the 2nd quarter of 2016 shows that as of June 2016, the actual non-clause O&M expenses for 2016 year to date were: 1) $6.2 million or 5.57% below budget for Gulf only; and 2) $2.3 million or 7.52% under budget for charges from Southern Company Services ("SCS") to Gulf. The same document shows that the Company has revised the projected 2016 non-clause O&M expenses specific to Gulf (i.e., excluding the portion charged from SCS) downward by $15.5 million or 6.68%. This reduces the 2016 budgeted non-clause O&M expenses from the $307,709,493 contained in the Company's approved 2016 Budget and Forecast to $292,207,769.

[4] Response to Citizens' PODs 20, 21 and 74.

In response to Citizens' POD 115, the Company provided the quarterly O&M budget variance reports for the 4th quarter of 2013 and for the 3rd quarter of 2016. The report for the 3rd quarter of 2016 shows as of September 2016, the actual non-clause O&M expenses for 2016 year to date were: 1) $7.98 million or 4.69% below budget for Gulf only; and 2) $4.66 million or 10.24% under budget for charges from SCS.

Q. HOW ACCURATE HAVE GULF'S NON-CLAUSE O&M EXPENSE BUDGETS BEEN FOR PRIOR YEARS?

A. Based on the 4th Quarter O&M budget variance report for the quarter ended December 31, 2013, the non-clause O&M expenses for Gulf only (excluding charges from SCS) was $18.9 million or 8.61% under budget. The same document shows that the non-clause O&M expenses charged to Gulf from SCS were $4.6 million or 8.30% under budget. Thus, on a combined Gulf and SCS basis, Gulf's actual non-clause O&M expenses were $23.5 million under budget in 2013.

Based on the 4th Quarter O&M budget variance report for the quarter ended December 31, 2014, the non-clause O&M expenses for Gulf only (excluding charges from SCS) was $6.0 million or 2.50% under budget in 2014.

Based on the 4th Quarter O&M budget variance report for the quarter ended December 31, 2015, the non-clause O&M expenses for Gulf only (excluding charges from SCS) was $8.9 million or 3.54% under budget. The same document shows that the non-clause O&M expenses charged to Gulf from SCS were $3.2 million or 5.32% under budget. Thus, on a combined Gulf and SCS basis, Gulf's actual non-clause O&M expenses were $12.1 million under budget in 2015.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE 2017 FORECAST AMOUNTS THAT WERE USED BY THE COMPANY AS THE BASIS IN PREPARING THE 2017 TEST YEAR IN ITS FILING?

A. Yes. In the remaining sections of this testimony, I recommend several adjustments to the forecasted amounts incorporated in the Company's 2017 projected test year. However, since the Company has not provided either its preliminary or its final 2017 Budget and Forecast, additional adjustments beyond those presented in this testimony may be appropriate.

<u>RECOMMENDED ADJUSTMENTS TO RATE BASE AND NET OPERATING INCOME</u>

Q. WOULD YOU PLEASE DISCUSS EACH OF YOUR SPONSORED ADJUSTMENTS TO GULF'S FILING?

A. Yes, I will address each adjustment I am sponsoring below.

<u>Removal of Vacant Positions</u>

Q. PLEASE PROVIDE A SUMMARY OF THE LABOR COSTS INCLUDED IN THE 2017 PROJECTED TEST YEAR FOR GULF EMPLOYEES.

A. Company MFR Schedule C-35 shows a projected average number of employees during the test year of 1,463 and projected test year total payroll cost of $143,011,260, consisting of

$121,023,102 in base payroll and $21,988,159 in “variable payroll.” The schedule also identifies fringe benefit costs of $36,971,542 resulting in total payroll and fringe benefit costs for the projected 1,463 employees of $179,982,802. Of the total $179,982,802, $114,577,427 is included in the adjusted test year O&M expenses as a significant portion of the payroll and fringe benefit costs are applied to capital or removed from the test year through the various clause adjustments or other adjustments. The $114,557,427 of payroll and benefit costs remaining in the adjusted test year O&M expense is for 1,450 Gulf employees and includes $80,381,375 for base payroll, $15,720,049 for variable payroll and $18,476,003 for fringe benefits.[5] This does not include the Southern Company Services (“SCS”) employee costs charged to Gulf.

Q. ARE THE LABOR COSTS BASED ON ACTUAL FILLED POSITIONS?

A. No. The labor costs are based on the forecasted positions incorporated in the Company’s 2016 Budget and Forecast for the 2017 forecast period, reduced by 13 employees to reflect the impact of the workforce reduction resulting from the planned installation of kiosks in Gulf’s offices discussed in Gulf witness Bentina C. Terry’s direct testimony. The result is the inclusion of labor costs associated with 1,450 forecasted Gulf positions.

Q. HOW DOES THE FORECASTED EMPLOYEE COMPLEMENT[6] INCORPORATED IN THE ADJUSTED 2017 TEST YEAR COMPARE TO HISTORIC EMPLOYEE LEVELS?

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[5] Response to Citizens’ Interrogatory 6.

[6] The number of employees (or “complement”) discussed throughout this testimony is on a full-time equivalent basis.

A. Company MFR Schedule C-35 shows that the actual average number of Gulf employees declined from 1,413 in 2013 to 1,397 in 2014 and 1,388 in 2015. The actual number of employees as of September 2016 declined even further to 1,357 employees.[7] Despite these consistent declines in the employee level, MFR Schedule C-35 shows that the Company projected a significant increase in employee complement between the historic year ended December 31, 2015 of 1,388 to 1,463 for the 2017 test year. This is an increase of 5.4%. After Gulf's adjustment to remove 13 employees from the 2017 test year, the filing still includes a 4.5% increase above the actual average 2015 employee levels.

Q. DOES GULF'S ACTUAL EMPLOYEE COMPLEMENT TYPICALLY EQUAL ITS BUDGETED EMPLOYEE COMPLEMENT?

A. No. During 2014, the Company budgeted for 1,470 employees. The actual average number of employees during 2014 was 1,397 and the actual number of employees as of December 2014 was 1,384, which was 86 less than budgeted.[8]

During 2015, the Company budgeted for 1,486 employees. The actual average number of employees during 2015 was 1,388 and the actual number of employees in December 2015 was 1,391, which was 95 less than budgeted.[9]

During 2016, the Company budgeted for 1,477 employees. As of September 2016, the actual number of Gulf employees was 1,357, which are 120 less than budgeted. In fact,

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[7] Response to Citizens' Interrogatory 1.
[8] Response to Citizens' Interrogatory 1 and Gulf MFR Schedule C-35.
[9] *Ibid.*

the number of employees has steadily been declining, going from 1,378 in May 2016 to 1,374 in June, 1,370 in July, 1,363 in August and 1,357 in September. The decline is consistent for all employee groups. The number of exempt employees went from 620 at December 2015 to 611 as of September 2016. The number of non-exempt, non-union employees went from 272 in December 2015 to 258 in September 2015. Similarly, the number of union employees went from 494 in December 2015 to 480 in September 2016.[10] Clearly, the Company's forecasted 4.5% increase in employee complement is not being realized; rather, the employee complement continues to decline.

Q. DO YOU AGREE THAT THE LABOR COSTS INCLUDED IN THE 2017 PROJECTED TEST YEAR SHOULD BE BASED ON THE COMPANY'S FORECASTED EMPLOYEE COMPLEMENT?

A. No, absolutely not. The Company's actual employee complement has been consistently below the budgeted amount for many years. Additionally, the Company's employee complement has continued to decline.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. As previously indicated, as of September 2016 the Company had 120 less employees than budgeted. Exhibit DMR-2, Schedule C-3 shows that the average per employee base payroll included in Gulf's adjusted test year O&M expenses is $55,435. This excludes the "variable payroll" (a/k/a, incentive compensation),[11] which is addressed separately in the

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[10] *Ibid.*

[11] The term "variable payroll", as used by Gulf, includes the Performance Pay Plan ("PPP"), Performance Stock Plan ("PSP") and stock options expense.

following section of this testimony. The schedule also shows the average per employee fringe benefit costs for medical and other group insurance, employee savings plan and worker's compensation that is included in the adjusted test year O&M expense is $9,013. These would include the employee benefits for which the costs more directly relate to the employee complement. The resulting combined average per employee O&M expense incorporated in the Company's adjusted test year for base payroll and certain fringe benefits is $64,448 ($55,435 + $9,013). This average amount per employee of $64,448 excludes the portion of labor costs going to capital and the portion charged to customers through the various clauses and only includes the amounts remaining in the test year O&M expense in this case.

As shown on Exhibit DMR-2, Schedule C-3, I recommend that the most recent number of vacant positions, or 120 positions, be removed from the 2017 test year at the average per employee O&M expense of $64,448, resulting in a recommended reduction to test year labor O&M expense of $7,733,760. This results in the adjusted test year labor costs, exclusive of the incentive compensation portion, being based on the most recent employee levels coupled with Gulf's anticipated employee reductions for 2017, such as the employee reductions associated with Gulf's implementation of the self-service kiosks for which the associated capital expenditures are incorporated in the Company's filing.

Q. GULF WITNESS SUSAN D. RITENOUR INCLUDED AN ADJUSTMENT IN THE TEST YEAR TO REDUCE LABOR COSTS FOR THE IMPACTS OF THE

HIRING LAG EXPERIENCED BY GULF. DOES YOUR ADJUSTMENT RESULT IN A DOUBLE-COUNTING OF THE HIRING LAG ADJUSTMENT?

A. No, it does not. It is appropriate to include both the hiring lag adjustment proposed by Ms. Ritenour and the vacancy adjustment recommended in this testimony. Ms. Ritenour's adjustment accounts for the impacts of employee turnover resulting in positions being temporarily unfilled as a result of voluntary and involuntary separations, retirements, deaths and transfers. My recommended adjustment accounts for the fact that many positions will remain vacant, consistent with the actual long-standing experience of Gulf. In response to Citizens' Interrogatory 48, the Company acknowledged that the hiring lag adjustment made by Ms. Ritenour does not factor in the impact of budgeted but vacant positions that are not filled in a given year. In its response, the Company also contends that the amounts in its test year budget "…includes only positions that are necessary to provide safe and reliable electric service to our customers and are projected to be filled."

Q. DO YOU FIND PERSUASIVE THE COMPANY'S CONTENTION THAT THE TEST YEAR, INCLUDING THE CURRENTLY VACANT POSITIONS, INCLUDES "…ONLY POSITIONS THAT ARE NECESSARY TO PROVIDE SAFE AND RELIABLE ELECTRIC SERVICE TO OUR CUSTOMERS AND ARE PROJECTED TO BE FILLED"?

A. Absolutely not. As indicated previously in this testimony, the Company's actual employee complement has over many years been consistently and substantially lower than budgeted, and has resulted in many vacant positions. To the best of my knowledge, the Company has not claimed that it has not been providing safe and reliable electric service to its customers during the many years that these budgeted positions have been vacant.

Incentive Compensation/Variable Pay Expense

Q. WHAT AMOUNT IS INCLUDED IN GULF'S ADJUSTED 2017 TEST YEAR FOR VARIABLE PAY OR INCENTIVE COMPENSATION EXPENSE?

A. MFR Schedule C-35 shows the 2017 forecasted test year includes $21,988,159 in incentive compensation, which Gulf has characterized as "at-risk" or "variable" payroll costs, for the forecasted level of Gulf employees. After the removal of the capital amounts, amounts recovered through clauses, and adjustments in Gulf's filing, $15,720,049 remains in the Company's adjusted test year O&M expense associated with forecasted Gulf employees. The $15,720,049 included in test year O&M expense consists of $13,576,581 for the Performance Pay Plan ("PPP"), $2,127,201 for the Performance Share Plan ("PSP") and $16,267 for Stock Options expense.[12]

In addition, the test year adjusted O&M expenses include $7,786,287 for incentive compensation (or variable payroll) forecasted to be charged to Gulf from affiliated entities. The $7,786,287 includes $6,130,791 for PPP, $1,579,617 for PSP, $65,410 for Stock Option costs and $10,469 for "Other" undefined variable pay.[13] Thus, on a combined basis, the adjusted test year O&M expense includes $23.5 million for various forms of incentive compensation.

[12] Response to Citizens' Interrogatory 11.
[13] Response to Citizens' Interrogatory 15.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE VARIABLE PAYROLL/INCENTIVE COMPENSATION EXPENSE INCLUDED IN THE TEST YEAR?

A. Yes. First, I recommend that 100% of the PSP expenses, Stock Option expenses and "Other" incentive compensation expenses be removed from the test year. Next, I recommend that the Gulf PPP expenses be reduced by $1,124,141 to remove the portion associated with the 120-position vacancy adjustment previously discussed. I then recommend that the remaining PPP be reduced by $3,089,703 to reflect the forecasted test year at the targeted payout level instead of an amount in excess of target. I then recommend that 33.33% of the remaining Gulf PPP expenses be removed, reducing the PPP Expense by an additional $3,120,912. Finally, I recommend that $3,057,713 of the PPP expenses charged to Gulf by affiliated entities be removed.

Q. CAN YOU PLEASE DESCRIBE THE PERFORMANCE SHARE PLAN?

A. The Performance Share Plan is a long term incentive program. Beginning in the 2017 test year, the Company is reducing the number of employees that participate in the Long Term Incentive Program from over 100 participants to 30 participants, shifting the costs by increasing the base pay for employees that will no longer participate in the PSP.[14] Under the Company's PSP, participating employees receive a grant of performance units at the beginning of the three-year performance period that are denominated in units representative of shares of Southern Company stock. At the end of each three-year period, employees <u>may</u> receive shares of Southern Company common stock. Gulf witness James M. Garvie's

[14] Direct testimony of James M. Garvie, page 13.

direct testimony, at page 12, indicates that the long-term goals under the plan consist of Southern Company total shareholder return, Southern Company earnings per share, and Southern Company equity weighted return on equity. Mr. Garvie's description of the PSP is consistent with the description of the long-term equity incentive program contained in Southern Company's 2016 Proxy Statement, which indicates 25% of the plan weighting is based on the Southern Company Earnings per Share goal, 25% is based on an equity-weighted ROE goal for Southern Company, and the remaining 50% is based on a Southern Company Total Shareholder Return (TSR) goal. The 2016 Proxy Statement, at page 44, includes the following statements with regards to the plan:

- "EPS supports our commitment to provide stockholders superior, risk-adjusted returns. Continuing to grow EPS is a factor in growing our dividend and TSR."
- "Equity-weighted ROE focuses on our efficiency at generating profits across our operating companies."
- "Keeping relative TSR at a 50% weighting for 2015 (as compared to a 60% weighting for the overall long-term program in 2014) ensures continued strong linkage to our stock price and alignment with investors while recognizing that market volatility can be the result of market cycles that are outside of management's control."

Clearly, each of the goals under the PSP, which is called the "long-term equity incentive pay program" in Southern Company's proxy statement, is focused on goals that benefit Southern Company's shareholders and directly links the interests of the plan participants with those of shareholders.

Q. DOES THE SIGNIFICANT REDUCTION IN THE NUMBER OF EMPLOYEES WHO WILL PARTICIPATE IN THE PLAN STARTING IN 2017 RESULT IN A LARGE REDUCTION IN THE PROJECTED TEST YEAR PSP EXPENSE THE COMPANY IS SEEKING TO INCLUDE IN RATES?

A. No. Gulf's response to Citizens' Interrogatory 11 shows the total PSP costs as $1,004,787 in 2013, $1,090,761 in 2014, $2,444,724 in 2015 and projected as $2,197,364 for the 2017 test year, $2,127,201 of which is included in the adjusted test year O&M expenses. Since the plan utilizes a three-year performance period, presumably the PSP cost reductions resulting from the significant reduction in participating employees will not occur until sometime after the 2017 test year, resulting in test year costs including both the labor costs that were shifted from the PSP expense to base labor costs and the projected 2017 PSP expenses.

Q. AT PAGE 25 OF HIS TESTIMONY, MR. GARVIE CONTENDS THAT GULF NEEDS TO PROVIDE A "LONG TERM, AT-RISK COMPENSATION PROGRAM" TO BE MARKET COMPETITIVE AND THAT OTHER UTILITIES AND MAJOR EMPLOYERS WITH WHOM GULF COMPETES FOR EMPLOYEES USE SUCH PROGRAMS. DO YOU FIND THIS TO BE A PERSUASIVE REASON TO ALLOW THE LONG TERM INCENTIVE PROGRAM TO BE CHARGED TO RATEPAYERS?

A. No, I do not. Mr. Garvie has presented no evidence demonstrating that regulated utilities in other jurisdictions are permitted to include long term incentive plan costs in rates charged to customers or that the comparisons are only to companies who are allowed to fully recover long term incentive compensation in rates. I have submitted testimony in rate case proceedings involving several of the peer group companies identified in Mr. Garvie's Exhibit No. __(JMG-1), Schedule 3, at pages 6 and 7. As a result of participating in those rate cases, I am aware that several of the peer group utilities identified by Mr. Garvie do not recover long term incentive plan costs in rates and do not recover the portion of their short term incentive plan costs that are determined based on achieving financial goals in rates. In any event, the relevant issue is not the extent to which other entities may provide such benefits, the relevant issue is who should bear the cost burden of Gulf's and Southern Company's long term incentive compensation plan – the shareholders or the ratepayers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PERFORMANCE SHARE PLAN COSTS INCLUDED IN GULF'S ADJUSTED TEST YEAR EXPENSES?

A. I recommend that the costs of the Performance Share Plan, as well as the Stock Options expense, be removed from adjusted test year O&M expenses. As previously indicated, the goals under the plan are tied to the Southern Company total shareholder return, Southern Company earnings per share, and Southern Company equity weighted return on equity. Thus, it is clear that the plan is focused on aligning the interests of the upper level executives that participate in the plan with Southern Company's shareholders, not Gulf's Florida ratepayers. As shown on Exhibit DMR-2, Schedule C-2, test year O&M expenses should be reduced by $2,143,000 to remove the Gulf PSP expense of $2,127,201 and Stock Options expense of $16,267. As shown on Schedule C-2, test year O&M expenses should also be reduced by an additional $1,655,000 to remove the projected test year charges to

Gulf from affiliates associated with PSP of $1,579,617, stock options of $65,410 and "other" variable pay of $10,469.[15] The amount of projected Stock Option Program expense included in the forecasted 2017 test year is minimal, as the Company has discontinued the program.

Q. IN YOUR OPINION, WOULD EXCLUSION OF THE RECOVERY OF THE PERFORMANCE SHARE PLAN EXPENSE FROM FLORIDA RATEPAYERS NEGATIVELY IMPACT GULF'S ABILITY TO ATTRACT AND RETAIN EMPLOYEES?

A. No. First, Gulf has indicated that the number of plan participants will significantly decline in the test year, going from over 100 participants to 30 participants. Thus, Gulf apparently does not view a significant reduction in plan participants as negatively impacting its ability to hire and retain employees. Additionally, the Commission disallowed the inclusion of the long term incentive compensation plan in rates in Gulf's 2012 test year rate case, yet the Company has continued the plan[16]. The Company has presented no evidence demonstrating that it was unable to attract or retain employees as a direct result of the Commission disallowing the recovery of the of the long term incentive plan cost in base rates.

Q. CAN YOU PLEASE DESCRIBE THE PERFORMANCE PAY PLAN?

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[15] The response to Citizens' Interrogatory 15 does not indicate what is included in the $10,469 of "Other" variable pay forecasted to be charged to Gulf from affiliates during the test year.

[16] See Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, In re: Petition for increase in rates by Gulf power Company, pages 91-98.

A. Yes. The Performance Pay Plan (PPP), which Company witness Garvie identifies as the annual portion of the "at-risk pay", is a short term incentive compensation plan that incorporates three categories of goals. Mr. Garvie describes the three categories of goals at page 10 of his testimony as: 1) Gulf operational performance, 2) Gulf net income performance, and 3) Southern Company earnings per share performance. The 2015 PPP final assessment provided by the Company in response to Citizens' POD 26 shows that the goals are weighted: 1/3 based on Southern Company's earnings per share ("EPS"); 1/3 based on business unit financial goals measured in net income; and 1/3 based on operational performance goals. The operational performance goals shown on the 2015 PPP scorecard include safety, customer satisfaction, generation, transmission and distribution SAIDI and SAIFI, and company culture.

Q. PREVIOUSLY IN THIS TESTIMONY, YOU RECOMMENDED THAT THE IMPACT OF 120 VACANT POSITIONS BE REMOVED FROM THE FORECASTED 2017 TEST YEAR. DO THESE VACANCIES ALSO IMPACT THE TEST YEAR INCENTIVE PLAN EXPENSE?

A. Yes. The Performance Pay Plan expense incorporated in the adjusted test year O&M expense, totaling $13,576,581, is based on Gulf's forecasted employee level, inclusive of the vacant positions, offset slightly by the Company's hiring lag adjustment. Consistent with my recommended removal of the base payroll and fringe benefit costs for the 120 vacant positions from the test year, the PPP costs included in the adjusted test year O&M expenses for these 120 vacant positions should also be removed. As shown on Exhibit

DMR-2, Schedule C-4, the PPP expense should be reduced by $1,124,141 to remove the amount of incentive plan expense associated with the vacant positions.

Q. PLEASE DISCUSS THE SECOND ADJUSTMENT TO GULF'S PPP EXPENSE SHOWN ON EXHIBIT DMR-2, SCHEDULE C-4.

A. One of the electronic workpapers provided by the Company for MFR Schedule C-35[17] shows that the estimated PPP payout incorporated in the 2017 test year is based on an assumed achievement of 133% of target. Thus, Gulf has apparently assumed that the payouts under the PPP will exceed the PPP targets in the test year by 33%. In setting rates, the amounts incorporated in base rates for the short term incentive compensation plan (i.e., PPP), should be based on the targeted performance level under the plan and not on an assumption that the employees will exceed their targeted level in the future test year. Otherwise, the implication is that the targets are being set artificially low in order to increase pay or to overstate the revenue requirement. As such, I recommend that test year PPP expenses remaining in the test year, after my recommended removal of the costs associated with the 120 vacant positions, be reduced by $3,089,703 to reflect only the targeted payout level in base rates.

Q. WHAT IS THE BASIS OF THE THIRD ADJUSTMENT TO THE PPP EXPENSE SHOWN ON EXHIBIT DMR-2, SCHEDULE C-4?

A. As previously indicated, 1/3 or 33.33% of the PPP goals is based on Southern Company's earnings per share. Clearly, this goal is focused on benefitting the shareholders of Southern

[17] Workpapers provided electronically by Gulf in excel format in response to Citizens' Request for Production of Document Nos. 1 and 2.

Company and not Gulf's Florida ratepayers. As such, I recommend that 33% of the remaining PPP expense (i.e., amount remaining after removal of vacant positions and reduction to reflect payout at target level) be removed from the test year, resulting in an additional $3,120,912 reduction to the PPP expense.

Q. WHAT IS YOUR TOTAL RECOMMENDED ADJUSTMENT TO GULF'S PPP EXPENSE?

A. Gulf's request includes $13,576,581 for the PPP in its adjusted test year O&M expense. As shown on line 10 of Exhibit DMR-2, Schedule C-4, the combination of my three recommended adjustments to Gulf's proposed PPP expense results in a $7,334,756 reduction to test year expenses. This would allow for the inclusion of the remaining $6,241,825 in the test year ($13,576,581 - $7,334,756).

Q. WHAT AMOUNT IS INCLUDED IN THE ADJUSTED TEST YEAR FOR PPP COSTS PROJECTED TO BE CHARGED FROM AFFILIATED ENTITIES?

A. The Company's filing includes $6,130,791 for projected charges from affiliated entities associated with the PPP.[18]

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE PPP COSTS CHARGED FROM AFFILIATES?

A. Yes. Assuming the forecasted PPP costs charged from affiliates also incorporates the assumption that the PPP is paid out in excess of the targeted level at 133%, I recommend

[18] Response to Citizens' Interrogatory 15.

an adjustment be made to reduce the payout to target level. As shown on Exhibit DMR-2, Schedule C-5, reducing the payout to target level, test year expenses charged from affiliates should be reduced by $1,521,174. Additionally, I recommend that the resulting affiliate PPP expense at target level be reduced by 1/3 or 33.33% to remove the portion that is applicable to the Southern Company EPS goal previously discussed in this testimony. This would result in an additional $1,536,539 reduction to test year expenses. As shown on Exhibit DMR-2, Schedule C-5, overall I recommend that Performance Pay Program expenses projected to be charged to Gulf from Affiliated entities during the test year be reduced by $3,057,713 ($1,521,174 + $1,536,539).

<u>Supplemental Executive Retirement Plan Expense</u>

Q. WHAT AMOUNT IS INCLUDED IN THE COMPANY'S ADJUSTED TEST YEAR O&M EXPENSES FOR THE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")?

A. Gulf's adjusted test year expenses include $2,655,201 for supplemental or nonqualified pension benefits, inclusive of charges to Gulf from affiliated entities.[19] The amount included in adjusted test year expenses for non-qualified pension benefits specific to Gulf employees is $1,509,354.[20]

Q. WHAT IS A SERP OR A NONQUALIFIED PENSION PLAN?

[19] Response to Citizens' Interrogatory 4.
[20] Response to Citizens' Interrogatory 6.

A. Section 415 of the Internal Revenue Service ("IRS") Code sets dollar limitations on the amount of annual benefits that participants can receive from "qualified" pension plans. SERPs or other non-qualified pension plans are "non-qualified" plans which were developed by some companies in response to the IRS setting limitations on the amount of dollars that could to be paid out annually from qualified pension plans. The IRS limit on the annual amount that participants can receive at retirement age for qualified defined benefit pension plans currently is $210,000. The IRS limit on the annual compensation that may be used in calculating the qualified retirement benefits that are deductible is currently $265,000 in 2016. The Company's nonqualified pension plans provide additional retirement benefits to select executives that are above and beyond the level of benefits the participants already receive through their participation in the qualified pension plan and the employee savings plan.

Q. IS THE COMPANY'S SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN STILL OPEN FOR NEW PARTICIPANTS?

A. No. The Company's response to Citizens' Interrogatory 14 indicates that the participation in the SERP was frozen with no new executives added to the plan after January 1, 2016.

Q. SHOULD THE COSTS ASSOCIATED WITH THE NONQUALIFIED PENSION PLANS BE INCLUDED IN RATES CHARGED TO FLORIDA RATEPAYERS?

A. No. Gulf's revenue requirement includes the costs associated with funding the qualified retirement plan costs as well as the employee savings plan costs. The non-qualified plans provide benefits to a select group of highly compensated executives that are above and beyond the benefits they receive through participation in the qualified plans. As previously indicated, the non-qualified plans provide for retirement benefits above and beyond the generous limits already allowed for qualified pension plans under the IRS regulations. If the Company decides to provide additional benefits that exceed the generous IRS limitations on qualified pension plans, then I recommend that shareholders fund the cost of the additional non-qualified plans. As shown on Exhibit DMR-2, Schedule C-2, I recommend that test year expenses be reduced by $2,655,000 ($2,615,000 jurisdictional) to remove the SERP expense from the test year.

<u>Pension Expense and Contribution</u>

Q. ABOVE YOU DISCUSS THE NON-QUALIFIED PENSION PLAN. CAN YOU PLEASE DISCUSS THE AMOUNTS INCLUDED IN THE COMPANY'S FILING ASSOCIATED WITH THE QUALIFIED PENSION PLAN?

A. Gulf witness Garvie's direct testimony, at page 27, indicates that the 2017 forecast includes $2,810,000 of pension costs. Company MFR Schedule C-35 shows that the $2,810,000 of pension costs includes $2,360,000 for the supplemental pension plan (i.e., the non-qualified plan) and $450,000 for the qualified pension plan. The response to Citizens' Interrogatory 6 shows that the adjusted test year O&M expenses include a credit balance of ($328,409) in pension expense. In other words, the filing, as adjusted by the Company, assumes pension income instead of expense.[21]

[21] The response to Staff Interrogatory 121 shows the total pension costs as being: 1) ($328,409) in expense; 2) ($91,626) capitalized; and 3) $870,035 as "Other", which would include clauses and below-the-line accounts.

Q. WHAT ADJUSTMENT DID THE COMPANY MAKE TO ITS 2017 FORECASTED PENSION COSTS?

A. Mr. Garvie indicates at pages 27 – 28 of his testimony that lower discount rates caused by market conditions have reduced the funded status of the pension plan, resulting in increased cost projections. To mitigate the increases, he states that Gulf will make an $81 million contribution to the plan in December 2016, $71.5 million of which will go to the funded status of the Gulf plan, and $9.5 million of which would apply to Gulf's allocated portion of the Southern Company Services (SCS) plan. In its filing, Gulf increased working capital by $81 million for the anticipated plan contribution and reduced pension expense by $665,000 for the impact of the contribution. Given the fact that the pension expense in the filing is a negative amount, which is indicative of pension income, it is not clear why Gulf has incorporated such a large projected contribution to the plan in its filing.

Q. IS GULF REQUIRED TO MAKE A CONTRIBUTION TO THE PLAN IN 2016?

A. No. The Form 10-Q filed with the Securities and Exchange Commission for the quarter ended September 30, 2016 indicates that no mandatory contributions to the qualified pension plan are anticipated for 2016. The 10-Q also shows that the net periodic pension costs for Gulf Power for the nine-month period ended September 30, 2016 was $5 million lower than for the nine-month period ended September 30, 2015. Thus, the pension expense has been declining for Gulf Power.

The 10-Q also discloses that a $125 million voluntary contribution was made to the Southern Company Gas qualified pension plan in September 2016; however, no reference was made to contributions being made to other Southern Company subsidiary plans. As will be discussed later in this testimony, Southern Company Gas was recently acquired by Southern Company.

Q. MR. GARVIE CITES LOWER DISCOUNT RATES AS CAUSING THE REDUCED FUNDED STATUS OF THE PENSION PLAN. AT THE TIME THE COMPANY PREPARED ITS FILING, WOULD IT HAVE BEEN KNOWN WHAT DISCOUNT RATES WILL BE USED IN THE 2017 ACTUARIAL CALCULATIONS USED IN DETERMINING THE PENSION PLAN EXPENSE THAT WILL BE RECORDED BY GULF IN 2017?

A. No. The discount rate, as well as other actuarial assumptions, to be used in determining the actual 2017 pension expense that will be recorded by Gulf are not determined until the end of 2016, which is after the date the Company's filing was prepared. Thus, the actual impact of any potential decline in the discount rate as compared to the discount rate used in preparing the 2017 forecast was not known at the time the testimony was prepared.

Q. DID INFORMATION PROVIDED TO THE COMPANY FROM THE ACTUARIAL FIRM IT USES FOR CALCULATING THE PENSION COSTS INDICATE THAT A LARGE CONTRIBUTION TO THE PLAN WAS NEEDED OR RECOMMENDED?

A. Citizens' POD 29 asked the Company to provide, in part, any information received from its outside actuarial firm regarding the $81 million contribution for December 2016 discussed in Mr. Garvie's testimony as well as information regarding cash contributions to the pension plan for 2016 and 2017.

*****BEGIN CONFIDENTIAL***** In its response, the Company provided an April 5, 2016 document from AON that included ten-year projections of Southern Company's retirement benefit plan costs and contributions. The document showed: a projected qualified pension cost for Gulf of $860,000 for 2017; the plan was projected to be 91.8% funded in 2017; and projected cash contributions to the Gulf plan would not occur until 2023.[22] An additional document was also provided that contained various qualified pension plan scenarios, which included a 75 basis point reduction in the discount rate assumption with and without additional December 2016 funding and projected minimum contributions with a 70 basis point reduction in the discount rate assumption. The scenario that contained a 70 basis point reduction in the discount rate showed a minimum contribution to the plan of $650,000 in 2017, but no minimum required contribution in 2016.[23] *****END CONFIDENTIAL***** This information, by itself, from the outside firm does not support the pension plan contribution and expense adjustment proposed by Gulf.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENT TO THE PLAN PENSION CONTRIBUTION AND PENSION EXPENSE INCLUDED IN THE COMPANY'S ADJUSTED TEST YEAR?

A. Yes. I recommend that the impact of the projected $81 million contributions be removed from working capital and that the associated adjustment to reduce pension expense by

[22] Confidential response to Citizens' POD 29 at 160186-OPC-POD-29-15, 17 and 19.
[23] Confidential response to Citizens' POD 29 at pages 160186-OPC-POD-29-1 to 5.

$665,000 be removed from the Company's adjusted test year. On Exhibit DMR-2, Schedule B-2, I reduce working capital by $81 million ($79,177,000 jurisdictional). On Exhibit DMR-2, Schedule C-2, I increase O&M expense by $665,000 ($655,000 jurisdictional).

Absent the Company providing documented proof substantiating that it did, in fact, make the $81 million contribution in December 2016, the Company's proposed increase in working capital should not be allowed. As indicated above, the actuarial assumptions for the 2017 plan year would have been selected by Gulf at the end of 2016. Additionally, the actual 2016 plan experience would now be known to the Company and its outside actuarial firm. If the Company did, in fact, make the contribution to the qualified pension plan and continues to seek inclusion of the contribution in its rebuttal testimony, then I recommend that as part of the rebuttal the Company also provide the current estimate of the 2017 pension expense (or income, if applicable) based on the actual 2016 plan experience and the 2017 actuarial assumptions that were selected in December 2016. The Company should also provide evidence that the contribution, if made, was prudent and results in a net benefit to customers. In the event of any potential proffered justification, the OPC should be afforded an opportunity to provide responsive testimony to such late-filed justification, if any.

Other Employee Benefits

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE TEST YEAR FOR OTHER EMPLOYEE BENEFITS AND HOW DOES THAT AMOUNT COMPARE TO PRIOR PERIODS?

A. The Company included $730,181 in its forecasted 2017 O&M expenses associated with Other Employee Benefits. This category of benefits includes deferred compensation, service awards, meals and travel, wellness programs, and other miscellaneous employee expenses. The actual expense for Other Employee Benefits charged to O&M expense was $380,689 in 2014, $461,749 in 2015 and $374,854 for January to August 2016.[24] The Company has projected a significant increase in these costs for the forecasted 2017 test year, increasing by $268,432 or 58% from the actual 2015 expense.

Gulf's response to Citizens' Interrogatory No. 13 shows that the Company is projecting deferred compensation costs and meal and travel costs to both more than double from the actual 2015 amount to the forecasted test year amount. The deferred compensation went from an actual 2015 expense of $120,895 to a projected expense of $266,409. Service awards costs are projected to increase from $191,385 to $265,711 in the projected test year. Meals and Travel costs are projected to increase from $46,030 in 2015 to $92,164 in the projected test year.

Q. ARE YOU RECOMMENDING THE FORECASTED 2017 OTHER EMPLOYEE BENEFITS EXPENSE BE ADJUSTED?

[24] Response to Staff Interrogatory 121.

A. Yes. I recommend that the expense be held at the actual 2015 expense level of $461,749. The Company has not supported the substantial projected increase in these costs. As shown on Exhibit DMR-2, Schedule C-2, I have reduced the Other Employee Benefits costs by $268,432, resulting in an adjusted test year expense of $461,749.

Payroll Tax Expense

Q. DO ANY OF YOUR RECOMMENDED ADJUSTMENTS IMPACT PAYROLL TAX EXPENSE?

A. Yes. In this testimony, I recommend several adjustments to the projected test year employee costs. This includes adjustments to remove the payroll expense associated with vacant positions and to reduce the incentive plan expense included in rates, each of which impacts payroll tax expense. Additionally, it does not appear that the Company reflected the impacts of its hiring lag adjustment on the test year payroll tax expense. On Exhibit DMR-2, Schedule C-6, I calculate the impact of the various labor adjustments and the Company's hiring lag adjustment on the projected test year payroll tax expense. As shown on this schedule, payroll tax expense should be reduced by $1,117,000 ($1,100,000 jurisdictional) to reflect the impact of the various labor cost adjustments. This amount was determined by applying the FICA rate of 7.65% to the various labor adjustments.

Property Damage Reserve Accrual

Q. HOW MUCH IS THE COMPANY CURRENTLY COLLECTING IN RATES ON AN ANNUAL BASIS FOR THE PROPERTY DAMAGE ACCRUAL?

A. The Company is currently collecting $3.5 million per year for the annual property damage accrual. This $3.5 million annual accrual rate was originally set in 1996 and was recently reevaluated by the Commission in Gulf's 2012 test year rate case.

Q. WOULD YOU PLEASE DISCUSS GULF'S PROPERTY INSURANCE RESERVE BALANCES?

A. Yes. In Gulf's last litigated base rate case, Docket No. 110138-EI, the Commission determined that the annual storm damage accrual should remain at $3.5 million and that the targeted reserve range should be increased from $48 million to $55 million. Through the annual collection of the reserve accrual of $3.5 million, the reserve balance has been steadily increasing, going from $24,045,884 at the beginning of 2010 to $40,173,002 as of October 2016.[25] Thus, over a period of 6 years and 10 months, the reserve balance has increased by approximately $16.1 million. The docketed case in which the current targeted reserve range of $48 million to $55 million was set used a 2012 test year. From the beginning of the 2012 test year in that case to October 2016 (a period of 4 years and 10 months), the balance in the reserve has increased by $9.7 million. Thus, the reserve is steadily increasing toward the targeted reserve balance established by the Commission as intended.

Q. WHAT IS THE COMPANY PROPOSING IN THIS CASE WITH REGARDS TO THE PROPERTY DAMAGE RESERVE ACCRUAL?

[25] Response to Citizens' Interrogatory 68.

A. Despite the steady progress being made towards achieving the targeted reserve balance, the Company is requesting a significant increase in the property damage reserve accrual. The Company proposes to increase the annual accrual by $5.4 million, resulting in an annual accrual of $8.9 million. Gulf's proposal would increase the currently approved annual accrual of $3.5 million by 154%.

Q. IS THE PROPERTY DAMAGE RESERVE INTENDED TO BE SUFFICIENT TO RECOVER THE COSTS OF ALL POTENTIAL STORMS THAT COULD IMPACT GULF?

A. No, it is not. As indicated by the Commission in its Order establishing Gulf's current targeted reserve balance, Order No. PSC-12-0179-FOF-EI, at page 29, the Commission's stated goal is that the reserve be sufficient to cover most, but not all, storms.

Q. IN THE EVENT A MAJOR STORM OCCURS CAUSING SIGNIFICANT DAMAGE TO GULF'S SYSTEM AND THE STORM COSTS EXCEED THE PROPERTY DAMAGE RESERVE BALANCE, ARE THERE OTHER OPTIONS AT THE COMPANY'S DISPOSAL FOR RECOVERY OF STORM COSTS THAT EXCEED THE RESERVE BALANCE?

A. Yes. As acknowledged at page 42 of Gulf Power Company's 2015 Annual Report (provided in MFR Section F – Miscellaneous Schedules, Volume One), "When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills." Thus, if a major storm occurs resulting in damages for which the costs exceed the storm reserve balance, the Company can request authorization of a storm cost recovery surcharge to recover prudently incurred restoration costs. The ability to seek recovery of the costs through a surcharge offsets Gulf's purported need to increase the balance to be recovered from ratepayers in current base rates. Under the various mechanisms available to Gulf to recover storm costs, the Company is adequately protected without the need to significantly increase the amount pre-collected in customer rates to fund the storm reserve.

Q. WHAT HAS BEEN THE ANNUAL LEVEL OF COSTS THE COMPANY HAS INCURRED FOR PROPERTY DAMAGES THAT HAS BEEN CHARGED TO THE PROPERTY DAMAGE RESERVE?

A. Company Exhibit JJH-1, Schedule 4 provided with the direct testimony of Company witness Janet J. Hodnett shows that over the period since Gulf's 2012 test year rate case, the annual average of "Non-Hurricane Charges to the Property Damage Reserve 2011 – August 2016" has been $1,029,000. Similarly, the Company's response to Citizens' Interrogatory 67 shows that for the period 2006 through October 2016 (a period of 10 years and 10 months), the total charges to the reserve inclusive of charges associated with hurricanes has been $12,045,461, resulting in average annual charges of $1,111,889. Thus, the annual reserve accrual has clearly exceeded the annual level of costs charged to the reserve, as demonstrated by the steady growth in the reserve balance.

Q. DID THE COMPANY SEEK TO INCREASE THE ANNUAL RESERVE ACCRUAL IN THE 2012 TEST YEAR RATE CASE?

A. Yes. In that case, the Company sought to increase the $3.5 million existing annual accrual by $3.3 million to $6.8 million annually. In its order, at page 29, the Commission determined that the record supported maintaining the annual accrual at $3.5 million, stating that "No pressing need has been identified to warrant an increase in the accrual at this time."[26]

Q. IN YOUR OPINION, HAS THE COMPANY DEMONSTRATED IN THIS CASE THAT THERE IS A PRESSING NEED TO INCREASE THE ANNUAL ACCRUAL ABOVE THE $3.5 MILLION THAT IS CURRENTLY AUTHORIZED?

A. No, it has not. As previously indicated, Gulf's property damage reserve balance has been steadily increasing. During that time, the annual costs charged to the property damage reserve has remained somewhat steady, averaging approximately $1 million per year since both the 2012 test year rate case and over a longer period of over ten years. The deductible levels for damage to insured property under the Company's insurance policies have remained the same since 2011.[27] Additionally, Gulf has been implementing storm hardening activities that are designed and intended to mitigate the impacts of storms on the Company's system. Of particular relevance to this issue is the fact that Gulf has the ability to seek recovery of storm damage costs through a surcharge mechanism if warranted. The Company has not demonstrated a pressing need to increase the annual accrual, particularly to the degree requested in this case.

[26] Order No. PSC-12-0179-FOF-EI at 29.
[27] Response to Citizens' Interrogatory No. 71.

Q. WHAT ADJUSTMENTS NEED TO BE MADE TO GULF'S FILING TO MAINTAIN THE EXISTING PROPERTY DAMAGE RESERVE ACCRUAL OF $3.5 MILLION PER YEAR?

A. As shown on Exhibit DMR-2, Schedule C-2, Gulf's proposed increase in the property damage reserve accrual of $5.4 million ($5,315,000 jurisdictional) should be removed. Additionally, as shown on Exhibit DMR-2, Schedule B-2, rate base should be increased by $2.7 million to remove the impacts of the Company's proposed adjustment on working capital.

<u>Insurance Expense</u>

Q. WHAT AMOUNT IS INCLUDED IN THE TEST YEAR IN FERC ACCOUNT 924 FOR ALL RISK INSURANCE EXPENSE AND HOW DOES THAT AMOUNT COMPARE TO PRIOR EXPENSE LEVELS?

A. Test year expenses in Account 924 – Property Insurance Expense include $4,716,972 for forecasted All Risk Insurance expense. The actual expense was $4,221,849 in 2014 and $4,099,815 in 2015. The Company's current projected expense for 2016, based on actual costs through September 30, 2016 and projected costs for the remaining three months of 2016, is $4,154,626.[28] Thus, despite the fact that the insurance expense has remained at approximately the $4.2 million level for the past three years, the Company has projected a $617,157 or 15% increase above the 2015 historic year expense in its filing.

[28] Company response to Citizens' Interrogatory 21.

Q. WHAT REASON DID THE COMPANY GIVE FOR THE PROJECTED 15% INCREASE IN THE INSURANCE COSTS?

A. The Company's response to Citizens' Interrogatory 21 indicates that the projected 2017 amounts are based on estimated insurance premiums and that "(t)he estimated premiums are based on prior premium rates escalated to account primarily for increases in property values due to inflation." Clearly, over the three-year period, 2014 through 2016, the costs have not increased due to "…increases in property values due to inflation."

Q. DOES THE COMPANY'S EXPLANATION JUSTIFY THE 15% INCREASE IN PROJECTED COSTS?

A. No. During the period 2014 through 2016, the actual all risk insurance expense has ranged between \$4.1 million and \$4.2 million, decreasing between 2014 and 2015 and slightly increasing between 2015 and 2016. The Company has not supported the projected 15% increase in these costs.

Q. HAVE THE COMPANY'S PAST FORECASTS OF PROPERTY INSURANCE EXPENSE BEEN ACCRUATE?

A. No, they have not. Based on a review Gulf's MFR Schedule C-6, the Company's property insurance expense recorded in Account 924, which would include the \$3.5 million annual storm reserve accrual and the annual All Risk Insurance expense, has been below the budgeted amount every year from 2011 through 2015.

Q. DO YOU RECOMMEND THE FORECASTED PROPERTY INSURANCE EXPENSE INCLUDED IN THE COMPANY'S FILING BE ADJUSTED?

A. Yes. I recommend that the Company's forecasted 2017 test year All Risk Insurance expense of $4,717,000 be reduced by $517,000 to $4.2 million, consistent with the actual costs incurred by the Company for the last three years. This $517,000 ($509,000 jurisdictional) reduction is included on Exhibit DMR-2, Schedule C-2.

<u>Uncollectible Expense</u>

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE ADJUSTED TEST YEAR EXPENSES IN ACCOUNT 904 – UNCOLLECTIBLE EXPENSE?

A. Gulf's test year expenses include $3,994,000 in Account 904 – Uncollectible Expense.

Q. HOW DOES THE AMOUNT INCLUDED IN THE ADJUSTED TEST YEAR COMPARE TO THE AMOUNT OF NET RETAIL WRITE-OFFS PRESENTED ON GULF'S MFR SCHEDULE C-11 FOR 2017?

A. On MFR Schedule C-11, the Company calculates its bad debt factor, which is the percentage of net retail write-offs (bad debt write-offs less recoveries of prior write-offs) to adjusted retail gross revenues. The schedule shows a four-year average bad debt factor for the period 2012 through 2015 of 0.2499% which Gulf then applies to the adjusted test year gross revenues, resulting in a projected amount of 2017 net write-offs of $3,149,000. The 0.2449% bad debt factor calculated on MFR Schedule C-11 is also used by the Company in calculating its net operating income multiplier on MFR Schedule C-44. The resulting net operating income multiplier that incorporates the 0.2449% bad debt factor is used to determine the amount of revenue increase needed for the Company.

The uncollectible expense included in the Company's filing of $3,994,000 is $845,000 higher than the projected net write-offs calculated on Company MFR Schedule C-11 of $3,149,000. To date, I have seen no information from Gulf explaining why the uncollectible expense included in the adjusted test year is so much higher (27%) than the result of applying the four-year average bad debt rate to the adjusted gross revenues.

Q. HAS THE COMPANY PROVIDED AN UPDATE OF THE UNCOLLECTIBLE EXPENSE IN PROJECTS TO INCUR IN 2017?

A. Yes. In response to Citizens' Interrogatory 183, the Company indicated that based on current information, it projects the uncollectible expense to be approximately $3.3 million in the 2017 test year.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO UNCOLLECTIBLE EXPENSE?

A. Yes. As shown on Exhibit DMR-2, Schedule C-2, I recommend the test year uncollectible expense included in Gulf's filing of $3,994,000 be reduced by $845,000, resulting in an adjusted uncollectible expense of $3,149,000. This results in the projected test year uncollectible expense being consistent with the expense that results from applying the four-year average bad debt rate to the adjusted test year gross retail revenues.

<u>Inflation Adjustment</u>

Q. YOU PREVIOUSLY INDICATED THAT THE 2016 BUDGET MESSAGE USED IN PREPARING 2016 BUDGET AND FORECAST WAS ISSUED OVER 18 MONTHS AGO IN JULY 2015. DID THE BUDGET MESSAGE INCLUDE GUIDANCE ON INFLATION?

A. Yes. Attachment D to the 2016 Budget Message provided “2016 Budget Assumptions.”[29] The Budget Assumptions included the following statement:

> Budget and cost estimates should be based on business needs and the actual expectations and projections of costs. The following information is provided for your use, only if applicable and in the absence of more appropriate factors or estimates.

The projected inflation incorporated in the Budget Assumptions was based on the Bureau of Labor Statistics: Consumer Price Index (Urban Consumer) from Moody’s Analytics that was issued in May 2014, which is over 2½ years ago.

Q. WHAT INFLATION RATE WAS PROVIDED IN THE 2016 BUDGET ASSUMPTIONS FOR 2017 AND HOW DOES THAT RATE COMPARE TO MORE RECENT FORECASTS?

A. The 2016 Budget Assumptions included a 3.7% inflation rate for 2017. The most recent 2017 Consumer Price Index received by the Company from Moody’s Analytics is 2.5% which was issued in November 2016.[30]

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[29] Response to Citizens’ POD 8

[30] Response to Staff Interrogatory 236.

Q. HAS THE COMPANY PROVIDED THE TOTAL AMOUNT OF O&M EXPENSE CONTAINED IN THE 2017 FORECAST, USED IN PREPARING THE 2017 TEST YEAR IN THIS CASE, THAT WAS BASED ON THE APPLICATION OF THE INFLATION FACTORS CONTAINED IN THE 2016 BUDGET ASSUMPTIONS?

A. In response to Staff Interrogatory 127, the Company stated as follows:

> The Consumer Price Index inflation factors are provided as part of the Budget Message only as an aid to Planning Units in developing their budget details. Quantification and justification of O&M expenses requires that the Planning Units examine and analyze the activities necessary to meet their goals and objectives, not simply escalate costs. Therefore, most Gulf Planning Units do not use the inflation factors in the preparation of their budgets or use them only to a very limited extent. Substituting the 3.7 percent included in the budget message for 3.6 percent would reduce the 2017 system adjusted O&M budget by $10,090. Please see page 2 for the calculation of this amount.

Page 2 of the response only identified amounts for the Generation, CFO and Corporate Planning Units as using the inflation rates, and only $10,089,772 of the budget amounts being inflated to the 2017 test year level. Intuitively, the $10,089,772 that the Company claims utilized the inflation factor in going from the 2016 budgeted amounts to the 2017 forecasted amounts seems extremely small when compared to the total 2016 non-clause O&M expense budget of $311,221,460. The portion of the 2016 non-clause O&M expense that was purportedly escalated is only 3.2% of the total budget. This would mean that 96.8% of the 2017 forecasted costs were not determined using inflation.

Q. ARE YOU RECOMMENDING A REDUCTION TO THE 2017 FORECASTED AMOUNTS INCORPORATED IN THE COMPANY'S FILING TO ACCOUNT FOR THE SIGNIFICANT REDUCTION IN THE PROJECTED 2017 CONSUMER PRICE INDEX?

A. Yes. I recommend that the outdated 3.7% inflation rate used by the Company in preparing the 2017 forecast be reduced to the current rate of 2.5%. As shown on Exhibit DMR-2, Schedule C-7, applying the lower inflation rate to the $10,089,772 that Gulf contends was inflated in the 2017 forecast results in a $121,000 reduction to the adjusted test year O&M expense. This should be considered the minimum inflation adjustment that should be made as I question the accuracy of the Company's contention in response to Staff Interrogatory 127 that such a small portion of the 2017 forecast was determined based on the application of inflation factors to the 2016 budgeted amounts. A larger inflation adjustment may be warranted.

<u>Southern Company Services Charges</u>

Q. WHAT AMOUNT DID THE COMPANY FORECAST FOR THE 2017 TEST YEAR FOR CHARGES FROM SOUTHERN COMPANY SERVICES ("SCS")?

A. In the 2016 Budget and Forecast that was used in preparing the 2017 test year in Gulf's filing, the Company forecasted $85,325,854 of charges from SCS to Gulf. Of the $85,325,854, $66,675,681 was for O&M expenses.[31] The remaining $18.65 million pertained to various non-O&M expense accounts, such as capital costs and below-the-line costs charged to FERC Account 426. After the various adjustments incorporated in the Company's filing, such as removal of O&M expenses that are recovered through various clauses and the pension expense adjustment, $64,289,000 remains in the Company's adjusted 2017 test year O&M expenses for charges from SCS.[32]

[31] Response to Citizens' Interrogatory 25.
[32] Response to Citizens' Interrogatory 22.

Q. WHEN WERE THE FORECASTED 2017 CHARGES TO GULF FROM SCS DEVELOPED THAT ARE INCORPORATED IN THE FILING FORECASTED BY GULF?

A. The charges from SCS that are incorporated in the 2017 test year were developed in 2015 as part of the 2016 budget and forecast process. The forecasted charges from SCS would include forecasted direct charges as well as forecasted costs that are allocated to Gulf from SCS based on numerous allocation factors used by SCS in charging costs to various operating companies. As explained in Gulf witness Janet J. Hodnett's testimony, at page 21, lines 18 – 19, the allocation factors that were used in preparing the forecast were based on 2016 budget allocators that were updated in 2015 based on 2014 actual data. In other words, the determination of the portion of the SCS costs that are allocated to Gulf for the 2017 test year were calculated based on 2014 data.

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE AMOUNT INCLUDED IN THE COMPANY'S ADJUSTED TEST YEAR O&M EXPENSE ASSOCIATED WITH COSTS FORECASTED TO BE CHARGED TO GULF FROM SCS?

A. Yes. Several of the adjustments previously discussed in this testimony include costs that are forecasted to be charged from SCS. These include: 1) the recommended removal of Performance Share Plan, Stock Option and "Other" unidentified variable pay charges from SCS to Gulf; 2) the recommended reduction to Performance Pay Program incentive compensation expenses charged to Gulf from affiliates; and 3) my recommended removal of the impacts of the forecasted voluntary pension plan contribution on pension expense, $271,000 of which is applicable to charges from SCS.

I also recommend that several categories of costs that are forecasted to be charged from SCS be excluded from base rates and not passed on to Florida ratepayers, resulting in an additional $2,013,000 reduction to the adjusted test year expenses.

Additionally, as will be explained in the next section of this testimony, Southern Company completed several significant acquisitions during 2016 that will impact the allocation factors that are used by SCS in allocating costs to Gulf and other operating companies that receive services from SCS. Since the allocation factors used in projecting the test year charges from SCS to Gulf were calculated based on 2014 data, they do not include the impacts of the recent Southern Company acquisitions. In the following section, I recommend an additional $6,362,000 reduction in the projected costs allocated to Gulf from SCS.

Q. WOULD YOU PLEASE DISCUSS EACH OF THE ADDITIONAL SCS COSTS YOU ARE RECOMMENDING FOR EXCLUSION FROM RATES AND EXPLAIN WHY THE COSTS SHOULD BE EXCLUDED?

A. Yes. The SCS charges that should be excluded from the test year and which have not been previously addressed in this testimony are shown on Exhibit DMR-2, Schedule C-8 which total $2,013,000 ($1,974,000 jurisdiction),[33] each of which are discussed below:

- SCS leases six active and one inactive Lear 45 fixed wing aircraft, leases one Sikorsky S76 C+ helicopter, and owns one Sikorsky S76 C+ helicopter. Test year expenses

[33] The jurisdictional separation factor for Other Operation & Maintenance expense on Gulf MFR C-1 was used for estimating the jurisdictional impact of the adjustment.

include $1,769,619 for charges from SCS associated with the operation and leasing of aircraft.[34] In response to Citizens' POD 132, Gulf indicates that there are no studies or analysis conducted by or for the Company, Southern Company and/or SCS regarding the cost effectiveness of using SCS aircraft for business travel as compared to publicly available air transportation. Given the significant costs charged to Gulf from SCS for the owned and leased aircraft, coupled with the lack of documentation and evidence demonstrating that the use of owned and leased aircraft is more cost effective than publicly available air transportation, I recommend that 50% of the costs be disallowed, resulting in an $884,810 reduction to the forecasted test year expenses.

- Forecasted test year O&M expenses in FERC Account 500 includes $153,853 associated with SCS Budget Work Orders ("BWO") 4799IN and $197,820 associated with BWO 4899IN is included in FERC Account 560. When asked for a "detailed description of what the projected costs are for" associated with these two BWOs, the Company responded: "Amount represents permanent tax differences for SCS income taxes."[35] The Company offered no further explanation for why the forecasted permanent tax differences for SCS's income taxes are projected to be charged to Gulf and included in Gulf's adjusted test year O&M expense in this case. The Company also has not demonstrated a benefit to Gulf's Florida ratepayers associated with these SCS tax issues. Therefore, I recommend that these costs be excluded from the test year, reducing test year expenses by $351,672.

[34] Response to Citizens' Interrogatory 33.
[35] Response to Citizens' Interrogatory 178 (public version).

- Test year expenses include $626,080 in BWO 47IV01 forecasted to be charged from SCS associated with Southern Company's new Energy Innovation Center that was recently opened in Atlanta, Georgia. The response to Citizens' Interrogatory 178 describes the costs as: "Development of new energy products and services at Southern's Energy Innovation Center." Gulf's response to Citizens' Interrogatory 181(e) describes the new Energy Innovation Center as one of the causes of a large projected increase in costs from SCS charged to FERC Account 923 between 2015 and the forecasted test year. The Company has not demonstrated a benefit to Gulf's Florida customers in the forecasted test year associated with Southern Company's new Energy Innovation Center, nor has it demonstrated that the costs of the center that are forecasted to be charged to Gulf will be outweighed by the benefits to Gulf's Florida customers. Gulf also has not demonstrated that the potential, future new products and services would not accrue to the benefit of Southern Company shareholders. Therefore, I recommend that the costs be excluded from the test year, reducing test year expenses by $626,080.

- Test year expenses include $149,968 in BWO 487C01 forecasted to be charged from SCS associated with Next Generation Nuclear R&D. The Company describes these costs as: "Research and development for non-light water reactor technology for the next generation of nuclear power plants."[36] Gulf witness Michael L. Burroughs indicated at his January 4, 2017 deposition that there are no plans at this time for Gulf to build a nuclear facility to serve its future Florida energy needs. Given the current

[36] Response to Citizens' Interrogatory 178.

lack of need for Gulf to build a nuclear facility to serve its Florida customers, the costs associated with SCS's research and development of the next generation of nuclear power plants should not be charged to Gulf's Florida ratepayers. Therefore, I recommend that the costs be excluded from the test year, resulting in a $149,968 reduction to test year expenses.

Southern Company Services – Allocation Adjustment

Q. IN ADDITION TO REMOVING SPECIFIC COSTS THAT ARE FORECASTED TO BE CHARGED TO GULF FROM SCS DURING THE TEST YEAR, SHOULD AN ADDITIONAL ADJUSTMENT BE MADE TO CHARGES FROM SCS ASSOCIATED WITH THE ALLOCATION FACTORS USED IN CHARGING COSTS TO GULF?

A. Yes. As previously mentioned, the allocation factors used in forecasting the costs to be allocated from SCS to Gulf during the 2017 test year were calculated in 2015 based on 2014 actual data. During 2016, Southern Company completed several significant acquisitions, the impacts of which are not included in the allocation factors that were used in forecasting the SCS expenses to be allocated to Gulf during the 2017 test year. Thus, an adjustment to the forecasted test year allocated charges from SCS should be made.

Q. WHAT ACQUISITIONS WERE COMPLETED BY SOUTHERN COMPANY DURING 2016?

A. In May 2016, Southern Company acquired all of the outstanding stock of PowerSecure International, Inc. for a purchase price of approximately $425 million, resulting in

PowerSecure becoming a wholly owned subsidiary of Southern Company. PowerSecure provides products and services in the areas of distributed generation, energy efficiency, utility infrastructure and solar energy.

On July 1, 2016, Southern Company completed a merger with Southern Company Gas (formerly known as AGL Resources, Inc.) for a purchase price of approximately $8.0 billion, resulting in Southern Company Gas becoming a wholly owned direct subsidiary of Southern Company. Southern Company Gas serves approximately 4.5 million customers and includes seven natural gas utilities operating in 7 states. The natural gas utilities include: Atlanta Gas Light in Georgia, Chattanooga Gas in Tennessee, Elizabethtown Gas in New Jersey, Elkton Gas in Maryland, Florida City Gas, Nicor Gas in Illinois and Virginia Natural Gas. Southern Company Gas also has wholesale and retail energy businesses and gas storage facilities. Clearly, this acquisition represents a significant expansion of Southern Company's operations.

Additionally, in September 2016 Southern Company Gas completed an acquisition of 50% of the equity interest in Southern Natural Gas, which owns a 7,000 mile pipeline system connecting various supply basins to various markets.

Q. IS THE NEWLY ACQUIRED SOUTHERN COMPANY GAS RECEIVING SERVICES FROM SCS?

A. Yes. Gulf's response to Citizens' Interrogatory 79 indicates that Southern Company Gas has been receiving the following categories of services from SCS "to varying extents":

General Executive and Advisory Services, Purchasing, Accounting and Statistical, Finance and Treasury, Taxes, Insurance and Pensions, Corporate, Rates, Budgeting, Business Promotion and Public Relations, Employee Relations, Systems and Procedures and Training.

Q. WILL THE ACQUISITIONS MADE BY SOUTHERN COMPANY IN 2016 IMPACT THE COSTS THAT WILL BE CHARGED TO GULF BY SCS DURING THE TEST YEAR?

A. Yes. As indicated above, Southern Company Gas has already begun receiving services from SCS. The addition of these entities will impact the calculation of the allocation factors that are used in allocating costs from SCS to the various Southern Company entities that it provides services to. The costs associated with many of the SCS functions will now be spread amongst a greater number of entities and should result in reductions to the costs that will be charged to Gulf from SCS.

Q. WAS THE COMPANY ASKED TO PROVIDE THE IMPACT OF THE SOUTHERN COMPANY ACQUISITIONS ON THE FORECASTED CHARGES TO GULF FROM SCS THAT ARE INCORPORATED IN ITS 2017 ADJUSTED TEST YEAR?

A. Yes. Citizens' Interrogatories 78 and 180 asked Gulf if these acquisitions will impact the costs allocated to Gulf from SCS and also for the impact on the 2017 adjusted test year resulting from the acquisitions. In response, the Company indicated that when the budget and forecast used in the filing was prepared during 2015, the merger with AGL resources was not contemplated for the 2017 forecast test year. Gulf's response to Citizens' Interrogatory No. 78 states: "As a result of the merger, certain allocation factors for Gulf may decrease; however, the budget for SCS will not be finalized until after December 31, 2016." Neither of Gulf's responses provided estimates of the impacts on the 2017 test year expenses forecasted to be allocated to Gulf from SCS that are incorporated in the Company's filing. Additionally, the Company disclosed in response to Citizens' Interrogatory 180, in part, that "Any impact of the Southern Natural Gas acquisition will not likely be included in the 2017 SCS budget due to the timing of when the acquisition was finalized in 2016." Thus, even when the 2017 budget is finalized, the Company does not anticipate that the impacts of the acquisition of Southern Natural Gas on the charges to Gulf from SCS will be included in its 2017 budget. Needless to say, it is disappointing that the Company has failed to meet its burden to even provide an informed and good faith estimate of the impacts of the recent Southern Company acquisitions and resulting changes in the SCS allocation factors on the adjusted test year expenses in its case.

Q. HAS THE ACQUISITION IMPACTED THE ALLOCATION FACTORS CURRENTLY BEING USED BY SCS IN CHARGING COSTS TO GULF?

A. Citizens' Interrogatory 73 asked the Company to provide, in part, a side-by-side comparison of the 2016 budget allocators used in this docket and the allocators currently being used in charging costs to Gulf from SCS. As part of its response, the Company provided a side-by-side comparison of the 2016 budget allocation rates (i.e., rates used in preparing the forecast test year charges from SCS to Gulf) to the current actual allocation rates being used by SCS. *****BEGIN CONFIDENTIAL***** I was able to reconcile most of the allocation factors shown in the response as the "2016 Plan Rates" to the allocation factors that were used in preparing the Company's projected test year charges from SCS in the filing, which were provided by Gulf in its Confidential response to Citizens' POD 44.[37] The comparison of the rates used in the test year to the current SCS allocation factors identifies many new and revised allocation factors being used which incorporate at least some of the additional operating entities post-acquisition. The response also provides the current allocation factors for the allocation factors that were not impacted by the acquisitions. Most of the allocation factors identified as currently in effect became effective in October 2016, which is post-acquisition.

The table below provides a comparison of some of the SCS allocation factors that were used by the Company in forecasting the test year charges from SCS to Gulf as compared to current allocation factors that were implemented by SCS in October 2016. Given the number of new allocation factors being used by SCS post-acquisition, the table below is not a straight apples-to-apples comparison. For example, for the employee factors and financial factors shown below, I have compared the SCS allocators that include most of the operating entities both before and after the acquisitions. Gulf's response to Citizens' Interrogatory 73 shows that SCS still has allocation factors that exclude the newly acquired entities that may be used in allocating certain costs for some of the SCS cost centers.

[37] Provided by Company in Confidential excel file titled: "OPC POD 44(A)_CONF-Attachment B".

TABLE CONFIDENTIAL Factor Title	Factor Used in 2017 TY Forecast	Current Factor With All Entities	Percentage Change
[redacted]	[redacted]	[redacted]	-3.00%
[redacted]	[redacted]	[redacted]	-24.20%
[redacted]	[redacted]		
[redacted]		[redacted]	-19.27%
[redacted]	[redacted]		
[redacted]		[redacted]	-14.48%
[redacted]	[redacted]		
[redacted]		[redacted]	-20.27%
[redacted]	[redacted]	[redacted]	-17.29%
[redacted]	[redacted]	[redacted]	-3.86%
[redacted]	[redacted]	[redacted]	-3.85%
[redacted]	[redacted]	[redacted]	1.63%

Source:
2017 TY Forecast from Tab "SCS Sofia All Ind" and consistent with Confidential response to Citizens ROG 73.
Current Factors from CONFIDENTIAL response to Citizens ROG 73.

As indicated in the above table, many of the allocation factors currently being utilized by SCS have declined since the factors used in calculating the forecasted test year charges from SCS were determined. *****END CONFIDENTIAL*****

Q. DO YOU RECOMMEND AN ADJUSTMENT BE MADE TO THE FORECASTED 2017 TEST YEAR EXPENSES ALLOCATED FROM SCS THAT ARE INCORPORATED IN GULF'S FILING?

A. Yes. The Southern Company acquisitions are significant events and the newly acquired entities are already receiving services from SCS. The addition of the newly acquired entities in the determination of the factors that are used to allocate costs from SCS will likely have a significant impact on the costs that will be allocated to Gulf from SCS, particularly when compared to the pre-acquisition allocation factors that were used by Gulf in preparing its filing. The Company has failed to meet its burden of providing an estimate of the impacts on the SCS allocated test year expenses incorporated in its filing that result from the recent Southern Company acquisitions and has already indicated that the full impact of the acquisitions will likely not be included in its 2017 SCS budget that is currently being prepared. Given Gulf's failure to provide the impacts, I have endeavored to estimate the potential impact on the forecasted test year expenses contained in Gulf's filing based on the information Gulf has provided to date in response to discovery in this case. As shown on Exhibit DMR-2, Schedule C-9, I recommend that the charges from SCS that remain in the adjusted test year O&M expenses, after reflecting the adjustments previously recommended in this testimony, be reduced by an additional 11%, resulting in an additional $6,362,000 reduction to test year expenses.

In the event the Commission does not adopt certain of my previously recommended adjustments to the test year expenses forecasted to be charged from SCS, totaling $6,455,000[38], then the recommended 11% reduction should be applied to each of the adjustments that the Commission does not adopt, thereby increasing the recommended $6,362,000 reduction shown on Exhibit DMR-2, Schedule C-9, line 8.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED 11% REDUCTION TO THE SCS CHARGES REMAINING IN THE ADJUSTED TEST YEAR O&M EXPENSES?

[38] Individual adjustments totaling $6,455,000 shown on Exhibit DMR-2, Schedule C-8 at lines 1 – 5 and Exhibit DMR-2, Schedule C-9 at lines 2 – 5.

A. First, I calculated the percentage of SCS charges included in the Company's test year expenses that were based on the projected allocation of costs from SCS. The costs that would be directly charged to Gulf from SCS would presumably not be impacted by the recent Southern Company acquisitions, only the allocated portion of the forecasted charges would be impacted. Costs that were forecasted to be charged to balance sheet accounts, such as capital accounts, and below-the-line to Account 426 were excluded in my calculation as they would not impact Gulf's test year O&M expenses. Based on a spreadsheet provided by the Company in response to Citizens' POD 44, as modified to remove capital costs and costs charged to below-the-line accounts[39], *****BEGIN CONFIDENTIAL***** 71.78% of the charges from SCS are projected to be allocated and 28.22% are projected to be directly charged.

As shown in the prior table, some of the allocation factors decline substantially once the newly acquired entities are factored in, and others change based on the Company's most recent calculations of the SCS allocation factors currently being used to charge costs to Gulf. The table previously presented with samples of some of the updates show changes ranging from an increase in an allocation factor of 1.63% to reductions in several of the factors being 14.48%, 19.27% and 20.27%. The table also shows that several of the allocation factors that do not incorporate the newly acquired entities in the calculations, such as coal generation, gas burned and load allocation factors, have also declined as compared to the amount used in preparing the Company's filing. In preparing the table, I

[39] Forecasted test year charges to Gulf from SCS by BWO and FERC account were provided by Gulf in response to Citizens' Interrogatory 25. This response was used to determine what amounts to remove in the response to Citizens' POD 44 to exclude the capital and below-the-line costs from the calculation.

reviewed the factors that were prevalent in the Company's calculation of the forecasted allocations from SCS incorporated in the Company's filing. Again, as previously indicated, many new allocation factors have been introduced post-acquisition, thus I was unable to provide a full side-by-side comparison of the factors used in preparing the Company's test year projections as compared to the factors currently in effect or to prepare a more precise estimate of the impacts of the new acquisitions on the 2017 SCS allocations to Gulf.

Given the information made available in this case, I recommend that the O&M expenses remaining in the adjusted test year associated with charges that are allocated to Gulf from SCS be reduced by 15% to reflect estimated impacts of the recent acquisitions. Applying the 15% reduction factor to the 71.78% of O&M expenses from SCS that were forecasted based on allocations (i.e., not direct charges) would result in a reduction of 10.77% (71.78% allocated x 15% reduction = 10.77%), which I have rounded to a recommended 11% reduction to the remaining SCS expenses. *****END CONFIDENTIAL*****

As shown on Exhibit DMR-2, Schedule C-9, application of the recommended 11% reduction factor to the remaining O&M expenses forecasted to be charged from SCS of $57,834,000 results in a recommended adjustment of $6,362,000 ($6,243,000 jurisdictional) to account for the impacts of the recent Southern Company acquisitions.

Deferred Return on Transmission Investment

Q. CAN YOU DESCRIBE THE DEFERRED EARNINGS ON CERTAIN TRANSMISSION PROJECTS THAT WERE ALLOWED AS PART OF THE STIPULATION AND SETTLEMENT AGREEMENT IN GULF'S PREVIOUS BASE RATE CASE?

A. Yes. Under item 10 of the Stipulation and Settlement Agreement in Gulf's prior rate case, Docket No. 130140-EI, filed November 22, 2013 ("2013 Settlement Agreement"), the Company was permitted to continue to accrue earnings equivalent to the AFUDC rate on its investment in certain transmission projects after the date the specified projects were placed into service. The additional earnings were deferred until January 1, 2017 under the terms of the 2013 Settlement Agreement. In its filing, the Company requests that the resulting regulatory asset for the return on transmission investment deferred through December 31, 2016 of $26,099,000 be amortized over a four-year period, resulting in an annual amortization expense of $6,525,000. The test year average unamortized balance is included in working capital in the Company's filing.

Q. DID THE 2013 SETTLEMENT AGREEMENT ADDRESS THE TIMEFRAME OVER WHICH THE RESULTING REGULATORY ASSET WOULD BE RECOVERED IN RATES?

A. No, it did not.

Q. DO YOU AGREE THAT THE REGULATORY ASSET SHOULD BE RECOVERED FROM RATEPAYERS OVER A FOUR-YEAR AMORTIZATION PERIOD?

A. No, I do not. The additional accrual of AFUDC-like earnings is similar to the application of AFUDC on assets under construction and residing in Construction Work in Progress. AFUDC accrued on assets under construction is recovered as part of depreciation expense over the life of the assets. The transmission assets for which the earnings were deferred for future recovery are long-lived assets that will be used and useful in providing service to customers over many years. Therefore, I recommend that the regulatory asset be amortized over the anticipated life of the transmission assets, consistent with the timeframe for which AFUDC is recovered on the assets.

Q. WHAT AMORTIZATION PERIOD DO YOU RECOMMEND FOR THE DEFERRED RETURN ON TRANMISSION INVESTMENT REGULATORY ASSET?

A. Gulf's response to Citizens' Interrogatory 66 shows that the majority of the transmission investments for which the earnings were deferred were recorded in FERC accounts 353 and 355, each of which have a 40-year remaining life in the Company's 2016 Depreciation Study.[40] Thus, I recommend that the resulting regulatory asset that was provided for in the 2013 Settlement Agreement be amortized over 40 years.

[40] Citizen's depreciation witness in this proceeding is not recommending a revision to Gulf's proposed depreciation lives for these two accounts.

Q. WHAT ADJUSTMENT IS NEEDED TO REFLECT YOUR RECOMMENDED 40 YEAR AMORTIZATION PERIOD?

A. As shown on Exhibit DMR-2, Schedule C-10, the annual amortization expense resulting from the recommended 40 year amortization period is $652,000, which is $5,873,000 less than Gulf's proposed amortization expense of $6,525,000. Additionally, working capital should be increased by $2,936,000 to reflect the impact of the longer amortization period on the 2017 test year unamortized regulatory asset balance.

<u>North Escambia Site</u>

Q. WHAT AMOUNT IS INCLUDED IN GULF'S REQUEST ASSOCIATED WITH THE NORTH ESCAMBIA SITE?

A. In this case, Gulf has included $13,043,000 ($12,679,000 jurisdictional) in Plant Held for Future Use ("PHFU") for 2,728 acres of land in North Escambia. It has also included $3,576,010 ($3,476,000 jurisdictional) in preliminary survey and investigation charges associated with the site in working capital. Thus, Gulf's proposed test year rate base includes $16,619,000 ($16,155,000 jurisdictional) for the North Escambia Site.

Q. DID GULF REQUEST INCLUSION OF THESE COSTS IN RATE BASE IN A PRIOR RATE PROCEEDING?

A. Yes. In Docket No. 110138-EI, the Company requested the inclusion of $27,687,441 ($26,751,000 jurisdictional) in rate base associated with North Escambia site costs, presenting it as a potential site for a future nuclear facility. Gulf has asserted that the North Escambia site is the only available location it has identified within its service territory that would be suitable for locating future nuclear generation. The $27,687,441 requested by Gulf in that docket included $18.1 million for 4,000 acres of land, $778,000 for other acquisition costs, $4.5 million for site investigation costs, $3 million for carrying costs, and other associated costs.[41]

Q. WHY IS THE COMPANY REQUESTING A LOWER AMOUNT FOR NORTH ESCAMBIA LAND IN THE CURRENT CASE?

A. The 4,000 acres at a cost of $18.14 million requested for inclusion in PHFU in the prior case included actual land purchases and projected additional purchases. PHFU in the current case includes the amount of land actually purchased, totaling 2,728 acres at a cost of $13 million. The land was acquired by the Company between 2008 through 2011 at costs ranging from $3,256.42 per acre to $78,302.85 per acre.[42]

Q. DID THE COMMISSION APPROVE INCLUSION OF THE ESCAMBIA SITE COSTS IN RATE BASE IN THE PRIOR RATE CASE?

A. No, it did not. In Order No. PSC-12-0179-FOF-EI, at page 26, the Commission rejected the inclusion of the Escambia site costs in rate base, finding, in part, as follows:

> 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 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

[41] Commission Order No. PSC-12-0179-FOF-EI at 26.
[42] Response to Citizens’ Interrogatory 118.

> 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. …

The same Order, at page 22, states that Gulf witness Burroughs indicated that in addition to being an option for future nuclear generation, the site was suitable for other generation technologies, including coal, gas and renewables.

Q. IF THE COMMISSION REJECTED INCLUSION OF THE ESCAMBIA SITE COSTS IN RATE BASE IN A PREVIOUS RATE CASE, WHY IS GULF INCLUDING THE COSTS IN THIS CASE?

A. Gulf witness Burroughs indicates that the Company's most recent Ten Year Site Plan reflects a projected 613 MW resource need in 2023. He also indicates that Gulf's current projections are that, if a gas-fired combined cycle (CC) plant is built to meet the forecasted 2023 need, the North Escambia site would be the lowest cost option as compared to other sites analyzed. Mr. Burroughs also indicated that if Combustion Turbine units (CT) are built to meet the forecasted 2023 need, the most economical alternative evaluated was to split the CTs between North Escambia and the Plant Smith location. Thus, the Company is once again seeking to include the North Escambia site costs in rate base through inclusion in PHFU and working capital.

Q. WERE THE NORTH ESCAMBIA SITE PRELIMINARY SURVEY AND INVESTIGATION COSTS GULF SEEKS TO INCLUDE IN RATE BASE, TOTALING $3,576,000, INCURRED IN THE PROCESS OF INVESTIGATING

THE FEASIBILITY OF THE SITE FOR PLACEMENT OF COMBINED CYCLE OR COMBUSTION TURBINE GENERATION UNITS?

A. No. The preliminary survey and site investigation costs the Company is seeking to include in rate base were associated with the possible placement of a nuclear facility at the site.[43] The Company provided a breakdown of the $3,576,010 in response to Citizens' Interrogatory 117. The response shows charges from outside consulting firms such as Bechtel and MacTec, costs associated with a meteorological tower installation, as well as affiliated costs including costs from Southern Nuclear. In its confidential response to Citizens' POD 90, the Company provided copies of the studies and reports that resulted from the preliminary survey and investigation costs incurred. The Confidential documents provided with the response *****BEGIN CONFIDENTIAL***** show that the report from Bechtel was for the "Escambia County, Florida Site Assessment and Layout Study for Multiple Nuclear Units", dated in August 2010, and was provided to the Project Manager at Southern Nuclear Company in Alabama.[44]

The Confidential response included a document titled "Summary of Geotechnical Studies - Celia Site Evaluation - Nuclear Siting Committee Activities."[45] The summary indicates that various studies were performed to evaluate the potential for development as a nuclear generation facility. The conclusion of the document indicated that additional geotechnical exploration needed to be done, recommending that it be done under "…a nuclear certified QA program" and that "This additional exploration will confirm that this is an acceptable

[43] Response to Citizens' Interrogatory 117.
[44] Company Confidential Response to Citizens' POD 90 at 160186-OPC-POD-90-2086.
[45] Company Confidential Response to Citizens' POD 90 at 160186-OPC-POD-90-2715 to 2720.

nuclear site, narrow down a suitable powerblock footprint location, and provide usable information for the conceptual design process." Thus, it is clear that the focus of the surveys and investigations were for determining the suitability for use of the property to site future nuclear operations and placement of potential nuclear facilities on property within the site.

If the Company, or one of its affiliates, decides to place a nuclear facility on the site at a future time, presumably the preliminary site studies and investigation would still benefit the construction and siting of the potential future nuclear facility if one is ever constructed. *****END CONFIDENTIAL***** Clearly, but for the effort to utilize the site for a nuclear plant, these costs would never have been incurred regardless of Gulf's claims that some use can be made of them for non-nuclear generation.

Q. HAS THE COMPANY MADE A FINAL DETERMINATION REGARDING WHETHER OR NOT ANY GENERATION UNITS WILL BE CONSTRUCTED ON THE ESCAMBIA SITE TO FILL GULF'S FORECASTED 2023 ENERGY NEEDS?

A. No, it has not. The information provided in this case indicates that Gulf is exploring various options for meeting its forecasted energy needs and that multiple sites are available to Gulf to construct future generation facilities. The Company's most recent Ten Year Site Plan filed in April 2016, at page 74, states: "Gulf's current plan is to either construct new generating facilities or purchase additional generating capacity by June 2023 of the current planning cycle following the expiration of its 885 MW Shell PPA." The Plan also states on page 74 that "Gulf will consider its existing Florida sites at Plant Crist in Escambia

County, Plant Smith in Bay County, and Plant Scholz in Jackson County, as well as its greenfield sites in Florida at Shoal River in Walton County, at Caryville in Holmes County, and at North Escambia in Escambia County as potential sites for locating future generating units in Northwest Florida." I have seen no information indicating that a final decision has been made to begin construction of new generation facilities on the North Escambia site. In fact, Gulf witness Burroughs agreed in a January 4, 2017 deposition that a determination has not yet been made regarding how Gulf will fill its forecasted 2023 energy needs and that the acquisition of additional generation capacity is still being considered.

It is my understanding that the numerous additional available sites are included in rate base and earning a return, either through inclusion in plant in service or inclusion in PHFU. Gulf is again seeking to include the additional North Escambia site in rate base as well.

Q. IF THE COMPANY DOES, IN FACT, DECIDE TO BUILD EITHER CC OR CT UNITS ON THE NORTH ESCAMBIA LAND TO MEET ITS FORECASTED FUTURE ENERGY NEEDS, HAVE YOU SEEN ANY EVIDENCE INDICATING THAT THE COMPANY WOULD NEED TO USE THE ENTIRE 2,728 ACRES FOR THE FACILITIES?

A. No, I have not. When the 2,728 acres were initially acquired by Gulf, it was being acquired as an option to site potential future nuclear facilities. The amount acquired was merely the stockpile of nuclear-capable land that had been collected before the decision to stop buying was made in the wake of the 2012 rate case order. The type of units that may be constructed on the site will impact the amount of land needed. In response to Citizens' Interrogatory

119, Gulf states that the number of acres needed for a gas fired CC on the site is dependent on requirements for obtaining a consumptive use permit, and that “[a] minimum of 2,728 acres will be required to obtain a consumptive use permit.” The response also indicates that the number of acres needed to place a CT on the site has not been determined. Despite the assertion in the response that the minimum acreage needed for a CC happens to equal exactly the amount of land previously purchased for siting a future nuclear facility, I have seen no substantive information indicating that the full 2,728 acres would be required to site a CC or CT on the Escambia land.

*****BEGIN CONFIDENTIAL*****A confidential document provided in response to OPC POD 91 provides a map showing the site potential for solar and CC/CT facilities. The map shows potential utility scale solar development on 400 to 550 acres of the land and 70 acres for potential “…single CC or 4CT footprint” as well as approximately 67 acres for substations.[46] Thus, the site map for the potential CC or CT units is minimal compared to the 2,728 acres Gulf is seeking to include in rate base in this case. Another map provided with the response showed additional potential solar facility locations on the site, indicating that two of the potential solar areas “may conflict with gas generation development” and several potential solar areas “may conflict with nuclear development.”[47] An additional document provided with the response, titled “Gulf Power Site Inventory” dated March 2016 indicates that a nuclear facility remains a potential application for the site, as well as natural gas CC and CT facilities and solar facilities. The document also indicates that there

[46] Confidential Response to Citizens’ POD 91 at 160186-OPC-POD-91-2 and 3.
[47] Confidential Response to Citizens’ POD 91 at 160186-OPC-POD-91-1.

is space for multiple units and applications on the North Escambia site.[48] *****END CONFIDENTIAL*****

Q. WHAT IS YOUR RECOMMENDATION WITH REGARDS TO THE NORTH ESCAMBIA SITE COSTS GULF SEEKS TO INCLUDE IN RATE BASE?

A. I recommend that the land included in PHFU be excluded from rate base. There are many additional sites already included in rate base that are available to be used to site future facilities. Gulf has not demonstrated that it has actual plans to construct facilities on the North Escambia site to meet its forecasted 2023 energy needs, nor has Gulf demonstrated that the entire 2,728 acres it acquired for a future potential nuclear facility will be needed to fill its forecasted 2023 energy needs. As shown on Exhibit DMR-2, Schedule B-2, I removed the full $13,043,000 ($12,679,000 jurisdictional) of North Escambia land costs from PHFU in rate base.

I also recommend that the Preliminary Survey and Investigation Costs be excluded from rate base. These costs were incurred during the period Gulf was considering the property for locating a future nuclear facility and were incurred for the purpose of evaluating whether or not the site was suitable for locating a nuclear facility. As shown on Exhibit DMR-2, Schedule B-2, I removed the full $3,576,000 ($3,476,000 jurisdictional) of North Escambia Preliminary Survey and Investigation Costs from the working capital component of rate base.

[48] Confidential Response to Citizens' POD 91 at 160186-OPC-POD-91-38 to 40.

Gulf Smart Energy Center

Q. WHAT IS THE GULF SMART ENERGY CENTER?

A. In this case, the Company is proposing to include $4 million of capital expenditures for construction of a "Smart Energy Center." The project is described in Gulf witness Terry's direct testimony, beginning at page 46. According to Ms. Terry, the proposed new facility will "… offer customer hands-on demonstrations where they can learn about the benefits of efficient electric end-use technologies as well as energy efficiency products and improvements" and the facility will "… showcase everything from electric transportation, comfort systems, cooking technologies and energy efficiency ideas for homes and businesses all under one roof." Gulf's response to Citizens' Interrogatory 46 indicates that the Smart Energy Center will provide a way for Gulf "… to expand [sic] role in educating and advising customers on ways to use energy more efficiently" and that the center will help customers "experience" technologies before buying.

Q. DID THE COMPANY CONDUCT A COST BENEFIT ANALYSIS FOR THE PROPOSED NEW SMART ENERGY CENTER?

A. No, it did not. Citizens' POD 77 asked the Company to provide a copy of the cost benefit analysis and any studies or analysis relied on by the Company in deciding to build the Gulf Smart Energy Center and in justifying the associated capital and operating expenditures. The Company responded that it did "… not possess documents which are responsive to this request." The response also indicated that the Company is requesting to recover capital expenditures and not operating expenses associated with the facility. However, based on a review of the capital additions in the Company's MFRs, it appears that the center was not projected to be completed until the end of 2017, thus, no operating expenses would be incorporated in the test year in the Company's request. Only the projected capital expenditures are incorporated in the current rate case.

Based on Gulf's response indicating that there were no cost benefit analyses or studies relied on in deciding to build the facility, it appears that Gulf did not conduct a study to determine if the building of a $4 million facility is the optimal use of ratepayer funds to be used in educating customers on energy efficiencies, or if such an approach is even cost effective.

Q. DO YOU AGREE THE CAPITAL COSTS ASSOCIATED WITH GULF CONSTRUCTING A NEW "SMART ENERGY CENTER" SHOULD BE CHARGED TO FLORIDA RATEPAYERS?

A. No, I do not. The Company has presented no evidence demonstrating that the costs of such a facility, projected to be $4 million in the Company's filing, are cost effective or reasonable. While such a facility may be a good public relations tool for Gulf and potentially allow Gulf to promote additional technologies that rely on electricity, I do not agree that the costs of the facility should be recovered from ratepayers, nor should ratepayers be expected to pay Gulf a return on the facilities. A "Smart Energy Center" is not a needed expenditure in the provision of cost effective and reliable energy service to Gulf's Florida ratepayers.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO REMOVE THE COSTS FROM THE TEST YEAR?

A. The Company's filing includes $1 million of expenditures in 2016 and $3 million of expenditures in the 2017 test year for the facility, resulting in $4 million of total expenditures. Based on a review of the Company's MFR Schedule B-8, it appears the project is projected to be placed into service in the final month of the test year. This is consistent with the Company's assertion in response to Citizens' Interrogatory 46 that there are no expenses in the test year for the Smart Energy Center as depreciation would not begin in the test year. Based on the $1 million of expenditures Gulf anticipated to make in 2016 and the full projected expenditures of $4 million, I reduced Construction Work in Progress by $2.5 million on Exhibit DMR-2, Schedule B-2 to remove the associated capital investment from the average forecasted test year rate base.

<u>Maintenance Outage Capital Expenditures</u>

Q. WHAT AMOUNT HAS THE COMPANY BUDGETED AND FORECASTED FOR 2016 AND 2017 CAPITAL EXPENDITURES ASSOCIATED WITH MAINTENANCE OUTAGES?

A. The Company's response to Citizens' Interrogatory 109 shows that the 2016 budget included $50,363,883 and the 2017 test year included $21,883,474 for capital expenditures associated with plant maintenance outages, exclusive of Scherer 3.[49]

[49] The 2016 budgeted and 2017 forecasted amounts for Scherer 3 is $2,819,780 and $6,281,514, respectively.

Q. HAS THE COMPANY REVISED THESE BUDGETED OR FORECASTED AMOUNTS?

A. Yes. Based on more recent information, the Company has reduced the budgeted 2016 amounts. Exhibit DMR-2, Schedule B-3 provides a side-by-side comparison of the maintenance outage capital expenditures contained in the Company's 2016 budget and the current 2016 projected amounts, by plant. As shown on the schedule, the Company's current projection is that the 2016 maintenance outage capital expenditures will be $7,053,551 lower than incorporated in the 2016 budget, exclusive of the Scherer 3 plant. The Company's response to Citizens' Interrogatory 109 provides explanations for the variances by plant, which includes descriptions such as decreases in the scope of some of the projects, some project costs being less than estimated, and the moving of some projects to 2018 or 2019.

Q. HOW WOULD THE REDUCTION IN THE 2016 BUDGETED CAPITAL EXPENDITURES IMPACT THE 2017 TEST YEAR?

A. The reduction in capital expenditures from what was budgeted in 2016 would reduce the plant in service and possibly the CWIP balances for the 2017 test year. As shown on Exhibit DMR-2, Schedule B-3, I recommend that the adjusted test year plant in service be reduced by $7,053,551 to reflect the impacts on the test year resulting from the reduction in 2016 maintenance outage capital expenditures. Additionally, the test year depreciation expense, based on the Company's proposed depreciation rates, should be reduced by $280,407 and accumulated depreciation should be reduced by $140,204 as a result of the recommended reduction to test year plant in service.

McDuffie Coal Terminal Inventory

Q. WHAT AMOUNT IS INCLUDED IN GULF'S REQUESTED WORKING CAPITAL BALANCE FOR IN-TRANSIT COAL?

A. Gulf's working capital request includes $20,934,000 for in-transit coal. This consists of $19,826,081 for coal inventory located at the McDuffie Coal Terminal, $682,308 for coal in-transit to Plant Daniel and $424,957 for coal in-transit to Plant Scherer.[50] In the 2012 test year rate case, the Company included $10,718,000 of in-transit coal in working capital. In his direct testimony, at page 39, Gulf witness Burroughs explains that the increase, which is approximately 95% above the 2012 test year level, is caused primarily by an increase in the quantity of coal being held at the McDuffie Coal Terminal.

Q. DID THE COMPANY EXPLAIN WHY THE COAL INVENTORY HELD AT THE MCDUFFIE COAL TERMINAL HAS INCREASED SO SIGNIFICANTLY?

A. Yes. In response to Citizens' Interrogatory 97, the Company provided the following explanation:

> Gulf purchases coal primarily under term contracts. Coal deliveries are scheduled to maintain target inventory, meet projected coal burn, and comply with contract volumes. During the last several years projected coal burn has not materialized due to continued lower gas prices making gas fired generation a more economic source of energy supply to Gulf's customers; therefore, coal inventory at McDuffie Coal Terminal has increased. Even with the increase of in-transit coal, our overall request in this case is $19,376,000 less than the amount allowed in the 2011 rate case (Docket 110138-EI).

[50] Response to Citizens' Interrogatory 97.

Q. THE RESPONSE INDICATES THAT THE OVERALL COAL INVENTORY IS LOWER IN THIS CASE THAN IN THE 2012 TEST YEAR CASE. WOULD YOU EXPECT THIS TO OCCUR?

A. Yes. Since the 2012 test year rate case, the Company has closed Smith Units 1 and 2 and Plant Scholz. The closure of these plants would obviously reduce Gulf's coal inventory needs.

Q. IS THE HIGH LEVEL OF IN-TRANSIT COAL LOCATED AT THE MCDUFFIE COAL TERMINAL ANTICIPATED TO CONTINUE ON A LONG-TERM BASIS?

A. No. As explained at page 37 of Mr. Burroughs' direct testimony, lines 6 – 18, coal inventory quantity as of December 2015 was above target levels as a result of lower coal burn quantity due to lower customer loads and low natural gas prices shifting the generation mix to natural gas fired generation. He explains that "Gulf expects to return coal inventory levels to the target quantity later in 2017 by reducing the amount of projected coal purchases to match the lower expected coal burn for the period." In his January 4, 2017 deposition, Mr. Burroughs indicated that the targeted level of inventory at the McDuffie Coal Terminal is 10 burn days, and that the quantity of coal incorporated in the Company's test year represents approximately 24 burn days.

Q. WHEN IN 2017 DOES GULF ANTICIPATE THE COAL QUANTITY WILL DECLINE TO RETURN TO TARGETED COAL INVENTORY LEVELS?

A. Based on a review of workpapers provided for Mr. Burroughs' testimony in response to Citizens' POD 3, the Company projects a significant decline in the in-transit coal held at the McDuffie Coal Terminal during July 2017 and August 2017. During this timeframe, the response also shows the coal quantity at the coal-fired plants remaining steady. Exhibit DMR-2, Schedule B-4 shows the projected quantity, cost and average cost per ton for coal inventory at the McDuffie Coal Terminal for the period December 2016 through December 2017. As shown on the schedule, the projected quantity of coal at the McDuffie Coal Terminal drops from 353,476 tons in June 2017 to 100,435 tons in August 2017. The cost of the inventory is projected to drop from $27,899,818 in June 2017 to $8,013,830 in August 2017.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE AMOUNT INCLUDED IN WORKING CAPITAL FOR THE IN-TRANSIT COAL AT THE MCDUFFIE COAL TERMINAL?

A. Yes. The Company acknowledges that the coal inventory levels are anticipated to decline to the targeted level during 2017. The Company has also acknowledged that the amount included in the adjusted test year at the McDuffie coal terminal exceeds its targeted level. Additionally, the decline to targeted levels is anticipated to occur within a month of the rates from this case taking effect. It would be unreasonable to include the McDuffie Coal Terminal inventory in working capital at the abnormally high levels that are not anticipated to occur during the rate effective period in this case. As shown on Exhibit DMR-2, Schedule B-4, I recommend that the amount included in working capital for the McDuffie Coal Terminal inventory be reduced from the $19,826,081 incorporated in the Company's filing to $7,820,596, which is a reduction of $12,005,486 ($11,660,000 jurisdictional). The recommended balance of $7,820,596 is based on the average projected inventory cost provided in the Company's workpapers for the period August 2017 through December 2017. The recommended quantity associated with the $7,820,596 balance of 104,417 tons shown on Schedule B-4 is also consistent with Gulf's 10 burn day inventory target for the McDuffie coal terminal.

Electric Vehicle Chargers

Q. SEVERAL COMPANY WITNESSES DISCUSS GULF'S PROPOSED OWNERSHIP OF ELECTRIC VEHICLE CHARGERS ON CUSTOMER PREMISES. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE ADJUSTED TEST YEAR ASSOCIATED WITH ELECTRIC VEHICLE CHARGERS?

A. Gulf's response to Staff Interrogatory 29 shows that the Company's adjusted test year includes the following amounts associated with Gulf's proposed ownership of electric vehicle (EV) chargers on customer premises: 1) $1,072,381 in average plant in service; 2) $130,331 in average accumulated depreciation; 3) $150,703 in depreciation expense; and 4) $238,586 in revenues. The workpapers provided for Company witness Ritenour's adjustments show that the projected revenues were calculated based on the application of the pretax cost of capital to the average test year net plant balance plus the depreciation expense.

Q. ARE YOU INCLUDING ANY ADJUSTMENTS IN THE OPC RECOMMENDED REVENUE REQUIREMENT CALCULATIONS ASSOCIATED WITH THE EV CHARGERS?

A. Yes. It is my understanding that OPC is not opposing the Company's proposed ownership of the EV chargers at this time, but that in the future steps should be taken to ensure that 100% of the costs are recovered only from the recipients of the EV chargers. The costs would include, but not necessarily be limited to, the return on associated net plant in service for the EV chargers, depreciation expense on the chargers and any O&M costs and administrative costs incurred by Gulf associated with the program. Additionally, it is OPC's position that while the Commission evaluates the proper long term regulatory treatment of costs associated with the EV chargers, including the propriety of utility ownership of EV chargers, all costs associated with the EV chargers should be excluded from future earnings surveillance reports. At this time, I am removing the plant in service, accumulated depreciation, depreciation expense and revenues associated with the EV chargers on Exhibit DMR-2, Schedules B-2 and C-2 to ensure that this program is revenue neutral to other customers in the test year. In calculating the jurisdictional amounts for the EV charger impacts removed on these schedules, I applied the jurisdictional separation factor used by Gulf witness Ritenour in determining the jurisdictional impact of the associated revenues of 0.9720737.

The Company's response to Staff Interrogatory 29 did not identify any O&M or administrative expenses in the 2017 forecasted test year associated with the proposed EV charger program. If any such O&M and administrative expense are included in the adjusted test year, they should be removed as well. I recommend that the Company clarify in its rebuttal testimony whether or not any O&M and administrative expenses associated with the program are included in the adjusted test year, and if so, provide the amounts included.

Construction Work in Progress

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN RATE BASE FOR CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A. Gulf's adjusted test year rate base includes $40,163,000 ($41,006,000 total system) for CWIP. After the reduction for the Gulf Smart Energy Center discussed above and the adjustment to remove CWIP associated with Scherer 3, the adjusted test year CWIP reflected in the per OPC adjusted jurisdictional rate base on Exhibit DMR-2, Schedule B-1 is $34,410,000.

Q. IS IT YOUR OPINION THAT CWIP SHOULD BE INCLUDED IN RATE BASE?

A. No. It is my opinion that CWIP should be excluded from rate base. Expenditures residing in the CWIP account are for plant that is not yet completed and not yet providing service to customers. In other words, CWIP is not used or useful in providing service to Gulf's electric customers. In many jurisdictions, CWIP is excluded from rate base as it is not yet used or useful in providing service to customers. Once the associated projects residing in CWIP are placed into service, they are transferred to plant in service, at which time the respective utility would begin to earn a return on and of the plant costs in the revenue requirements in subsequent rate case proceedings.

Q. SINCE IT IS YOUR OPINION THAT CWIP SHOULD BE EXCLUDED FROM RATE BASE, WHY DOES CWIP REMAIN IN THE OPC ADJUSTED RATE BASE ON YOUR EXHIBIT DMR-2, SCHEDULE B-1?

A. The Florida Public Service Commission has consistently allowed the inclusion of non-interest bearing CWIP in rate base for electric utilities. Given the Commission's practice of allowing the non-interest bearing CWIP in rate base, I did not remove the adjusted CWIP balance on Exhibit DMR-2, Schedule B-1. However, the fact that the OPC's recommended rate base includes non-interest bearing CWIP should not be construed as meaning that the OPC's position, nor my opinion, on this policy issue has changed. OPC may opt to further address this important issue in future rate proceedings.

Income Tax Expense

Q. HAVE YOU ADJUSTED INCOME TAX EXPENSE TO REFLECT THE IMPACT OF YOUR RECOMMENDED ADJUSTMENTS TO NET OPERATING INCOME?

A. Yes. On Exhibit DMR-2, Schedule C-11, I calculate the impact of federal and state income tax expenses resulting from the recommended adjustments to operating expenses.

Interest Synchronization

Q. WHAT IS THE PURPOSE OF YOUR INTEREST SYNCHRONIZATION ADJUSTMENT ON EXHIBIT DMR-2, SCHEDULE C-12?

A. The interest synchronization adjustment allows the adjusted rate base and cost of debt to coincide with the income tax calculation. Since interest expense is deductible for income tax purposes, any revisions to the rate base or to the weighted cost of debt will impact the test year income tax expense. OPC's proposed rate base and weighted cost of debt differ from the Company's proposed amounts. Thus, OPC's recommended interest deduction for determining the test year income tax expense will differ from the interest deduction used by Gulf in its filing.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

(Transcript continues in sequence with Volume 4.)

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

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

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

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

DATED THIS 22nd day of March, 2017.

Linda Boles

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