BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 110138-EI

PETITION FOR INCREASE IN
RATES BY GULF POWER COMPANY.
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VOLUME 7

Pages 1053 through 1287

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, December 13, 2011

TIME: Commenced at 4:17 p.m.
Concluded at 7:10 p.m.

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

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6732

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
20			10
195	PSC Rule 25-6.0423	1122	
150	Witness McMillian Deposition Transcript of 11/16/11	1163	1163
196	Late-filed Exhibit Numbers 2, 3, 6, and 7	1163	1179
197	Gulf's Response to FEA's First Set of Interrogatories Item 15	1165	1179
21-23			1179
151, 153			1182
154-156			1182
198	MTO-W	1214	1237
199	O'Sheasy Revised MFR Schedules E6A and E6B	1216	1237
24			1237
200	JIT-2	1267	1283
201	Revised Schedule 2, JIT-2	1268	1283
25			1283

P R O C E E D I N G S

(Transcript follows in sequence from Volume 6.)

CHAIRMAN GRAHAM: Please, go ahead.

MAJOR THOMPSON: I had a quick administrative matter. Mr. Gorman was supposed to go after the OPC witnesses. I wanted to see if we could get him to go into -- Chinese cut in front of the OPC witnesses.

CHAIRMAN GRAHAM: Hold on just a second. Who was supposed to go on?

MAJOR THOMPSON: Mr. Gorman, he's the last name on the page.

CHAIRMAN GRAHAM: Okay.

MAJOR THOMPSON: And I'm going to have him go where Mr. Pollock would have gone.

CHAIRMAN GRAHAM: You want him to go where -- after Mr. Pollock that was just stipulated?

MAJOR THOMPSON: Right, in that area.

CHAIRMAN GRAHAM: Commissioner Edgar, or OPC?

COMMISSIONER EDGAR: Yes, Mr. Chairman.

CHAIRMAN GRAHAM: You were Prehearing Officer. My first question is does OPC have any objection to that?

MR. McGLOTHLIN: No. We told the Major that we could accommodate that.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Mr. Chairman, the order of witnesses is in the prehearing order as was requested by the parties, and I believe we did have a brief discussion at the prehearing that if there was a desire to change the order and there was not disagreement, that that would be your purview, and I have no problem with it.

CHAIRMAN GRAHAM: Any objection to moving Witness Gorman?

MR. STONE: We have no objection to moving. I would point out that we have offered to stipulate his testimony into the record.

CHAIRMAN GRAHAM: Okay.

MR. MOYLE: No objection from FIPUG.

CHAIRMAN GRAHAM: Major, would you like to stipulate him?

MAJOR THOMPSON: No, sir.

CHAIRMAN GRAHAM: I figured I would ask, Mr. Stone.

MAJOR THOMPSON: One last thing, Mr. Chairman.

CHAIRMAN GRAHAM: Sure.

MAJOR THOMPSON: I wanted to make sure the FEA gets on the record for the objection with the intervenors for the depositions in the record. I want to join in that, as well.

CHAIRMAN GRAHAM: You want to join the objection for all the depositions and for Exhibit 194?

MAJOR THOMPSON: 194? No, just the depositions.

CHAIRMAN GRAHAM: I'm sorry, that was just FIPUG. Okay. All right. I think we're ready to roll.

MR. STONE: Mr. Chairman, the next witnesses in the order as presented on the prehearing order are a panel. They would be Mr. Scott C. Twery and Ms. Ann E. Crumlish. They were stipulated, and so I would ask that their testimony consisting of 13 pages be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert their testimony into the record as though read.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Scott C. Twery and Anne E. Crumlish
Docket No. 110138-EI
In Support of Rate Relief
Date of Filing: July 8, 2011

Q. Mr. Twery, please state your name, business address and occupation.

A. My name is Scott C. Twery. My business address is 3350 Riverwood Parkway, Suite 80, Atlanta, GA 30339. I am a Principal and Consulting Actuary in Aon Hewitt's retirement practice. Aon Hewitt is a global market leader in Human Resources consulting and outsourcing with 29,000 colleagues serving more than 20,000 clients.

Q. Please summarize your educational and professional background.

A. I have worked for over 30 years as an actuary consulting with companies about their retirement benefit programs. I am a Fellow of the Society of Actuaries and an Enrolled Actuary. I earned a Bachelor of Science in mathematical sciences with an actuarial science emphasis. I have consulted with Gulf Power Company (Gulf, or the Company) and Southern Company for over 20 years on their benefit programs. During that period, I have led actuarial teams that have determined the companies' retirement benefit costs and consulted with them on benefit competitiveness.

Q. Ms. Crumlish, please state your name, business address and occupation.

A. My name is Anne E. Crumlish. My business address is 3350 Riverwood Parkway, Atlanta, GA 30339. I am a Principal and Consulting Actuary in Aon Hewitt's health and benefits practice.

Q. Please summarize your educational and professional background.

A. I have over 10 years of experience as a health care consultant and actuary. I am a Fellow of the Society of Actuaries and a Member of the American Academy of Actuaries. I earned a Bachelor of Arts in Mathematics and Master of Arts in Mathematics with a focus in actuarial science. I have served as Southern Company's and Gulf's health care actuary for over nine years. I currently lead an actuarial team that determines the companies' health care benefit costs and consults with them on benefit design and competitiveness.

Q. Are you sponsoring any exhibits in this case?

A. Yes. We are sponsoring the following three schedules which are attached to our direct testimony:

- Exhibit SCT-1, Schedule 1, Aon Hewitt Comparison of Employer-Provided Total Benefit Values
- Exhibit AEC-1, Schedule 1, National Employer Health Plan Average Annual Cost Increases, 2001-2012
- Exhibit AEC-1, Schedule 2, Medical Plan Cost Mitigation Efforts 2003-2012

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the relative competitiveness of Gulf's overall benefits program, give reasons why retirement benefit costs have increased, and explain why medical benefit costs have increased. Ms. Crumlish will address medical benefit costs. Mr. Twery will address the other two topics.

Q. Are the benefits programs provided to Gulf's employees, Southern Company plans or Gulf plans?

A. Most of the benefit plans are Southern Company plans. Managing a benefit plan for all of Southern Company is more cost effective than maintaining separate plans for each subsidiary. Even so, the costs determined for Gulf are directly attributable to Gulf's employees. For example, when Gulf's retirement benefit costs are determined, the calculations only involve Gulf's employees and Gulf's portion of retirement plan assets. Another example is Gulf's health care benefit costs. These costs are an allocation of pooled expenses determined by the actual plan option and family coverage tiers selected by each Gulf employee. All references in the remainder of our testimony will be to Gulf, even if the plan is administered by Southern Company.

Q. As a result of your work for Gulf, are you familiar with the Company's overall benefits philosophy?

A. Yes. My understanding is that the Company has a goal for its benefits to be at the median of the market.

Q. Has Aon Hewitt made an assessment of how Gulf's benefits compare to the market and if so, how does Gulf's benefit package compare to the market?

A. Yes. We performed an assessment of Gulf's benefits and we found them to be competitive with other large utilities and Fortune 500 companies.

Q. What is the basis of your conclusion that Gulf's benefits are competitive?

A. Our response is based on a benefits competitiveness analysis we made of the benefits that Gulf and the comparator companies offered in 2010. The analyses were done using Aon Hewitt's Benefit Index®. The Benefit Index is a premier tool for comparing the relative worth of one company's benefit programs to those offered by a group of other companies. It has been used by companies since the 1970s to make such assessments.

When last assessed, the relative value of benefits Gulf provides its employees is 5.8 percent below the average value of benefits provided by 15 other large utilities and 4.6 percent above the average value of benefits provided by Fortune 500 companies. Generally, value differences are not considered significant or material until they exceed 5 percent. So it is fair to say that Gulf-provided benefits are slightly less valuable than those at other large utilities and nearly in line with those at Fortune 500 companies.

Q. How were the benefit competitiveness assessments made?

A. Benefit Index results are arrived at using a very specific process. Actuarial techniques are used to measure the total value a representative population of employees would derive from Gulf's benefits program and the benefits programs of each of the comparator companies. All retirement income, death, disability, healthcare, and paid time off benefits offered to salaried hires are included. These actuarial values reflect the benefits that each program would be expected to pay during a year and the present value of the benefits employees would be expected to earn during a year but receive in the future, like pension benefits. The same employee population and assumptions are used when measuring the values for each of the programs. This standardization assures that the differences in benefit values are attributable to plan designs. Finally, the value of Gulf's benefits program is compared to the average of the values for the comparator group's programs to arrive at a relative value result reported by the Benefit Index. A relative value of 100.0 would be assigned if Gulf's benefit value equaled the average value of the benefits offered by the comparator companies.

Benefit Index relative values for Gulf's benefits versus the 15 large utilities and Fortune 500 comparator groups were 94.2 and 104.6 respectively. The 94.2 indicates Gulf's standardized value of benefits was 5.8 percent below the average of the utilities and the 104.6 indicates that Gulf's standardized value of benefits was 4.6 percent above average for the Fortune 500 comparators.

Exhibit SCT-1, Schedule 1, contains a chart showing the relative value of Gulf's benefits versus the average of two comparator groups. In addition, that chart shows the distribution of the relative values of comparator companies' benefits around the average. As shown on that chart, the median of each comparator group is essentially the same as the average. For that reason, market average and market median are effectively the same for purposes of this competitive analysis.

Q. The title on Schedule 1 of Exhibit SCT-1 refers to "Employer-Provided Total Benefit Values." Please explain.

A. Two scores are actually produced in the Benefit Index study. One is Total Benefit Value which reflects the full value of the benefits program. The other reflects only Employer-Provided Benefit Value which is the Total Benefit Value reduced by the value of employee/retiree contributions required to receive the benefits. For market competitiveness, the Employer-Provided Benefit Value is normally used since it represents the portion of benefits for which companies pay. Gulf's Total Benefit Values versus both the utility and Fortune 500 comparator groups were just a bit higher than its Employer-Provided Benefit Values. This indicates Gulf is charging its employees/retirees more for benefits than the comparator companies do on average.

Q. Did you recently provide revised retirement benefit expense projections to Gulf?

A. Yes. In March 2011, I provided updated expense projections for pensions, retiree medical, and retiree life benefits based on the formal actuarial measurements done as of the end of 2010. The new projections portray lower 2011 and 2012 expenses for these benefits than earlier projections did. The decline is attributable to 2010 events and related changes in estimates. I have been informed that these revised projected expenses for the 2012 test year are in total $2.7 million lower than the estimate contained in the Company's 2011 financial model. I also understand that Gulf Witness McMillan makes an adjustment to reflect this expense reduction in the Company's rate request.

Q. Did Gulf Witness Erickson provide you with information on Gulf's projected A&G O&M benefits costs for the 2012 test year and how they compare to the Commission's O&M benchmark?

A. Yes. Ms. Erickson informed us that Gulf's total projected A&G O&M benefit costs for the test year are approximately $20.7 million, which is approximately $10.1 million above the benchmark. Ms. Erickson states in her testimony that the projected retirement plan expense is $6.9 million above the benchmark, and projected medical plan and group insurance is $3.3 million above the benchmark. Also, she has informed us that primary contributors to the $6.9 million and $3.3 million differences were the pension and medical benefit expenses, respectively. The explanations we provide about why pension and medical benefit expenses have increased will also explain other variances that we understand are attributable to these benefit costs, including those Ms. Erickson's testimony has identified as related to joint ownership and duplicate charges.

Q. Why have pension expenses increased by as much as they have since the costs were projected for the prior 2002-2003 test year?

A. Pension cost increases are attributable to a number of factors, but the primary factor has been measurement losses. Simply put, pension plan assets are less than they had been anticipated to be and liabilities are higher than they had been expected to be. These losses offset some of the gains that Gulf experienced in prior years. Due to those gains, Gulf had more pension assets than liabilities for quite a few years, and Gulf's pension expenses were actually negative for quite some time, including the last test year. In other words, Gulf's pension was actually contributing to income in spite of Gulf's employees earning benefits each year. The losses and liabilities associated with the normal benefit accruals have finally eroded the surplus resulting from the prior gains, and pension expenses are projected to be higher as a result. Note that the pension expenses being referred to are calculated for the Company's accounting and financial reporting purposes. They are determined according to very specific rules set out by the Financial Accounting Standards Board.

Q. What has been the source of these pension losses?

A. There have been two primary sources. First, while pension plan assets earned about $102 million of return over the period from when the last test year's costs were projected through 2010, that amount is about $123 million less than the returns that had been expected during that period. Nearly all of these reduced investment earnings result from the stock market crash early in the century and the 2008 "Great Recession."

Second, pension benefit liabilities are about $67 million higher than had been anticipated. Out of the many factors influencing the size of liabilities, the change in the level of discount rates explains the vast majority of the additional liabilities. Essentially, these liabilities are the present values of the pension benefits that Gulf employees have earned and are expected to receive in the future. The discount rate currently being used is about 200 basis points lower than the discount rate used when pension expenses for the last test year were projected. That is because GAAP accounting rules mandate discounting the future benefit payments using market interest rates, and these market rates are significantly lower today. The lower rate of discount pushes up the pension liabilities.

Gulf's situation is not unique. Essentially, all pension plan sponsors incurred losses during the period since costs were projected for the last test year due to the general economic circumstances that caused interest rates to fall and investments to perform poorly.

Q. What has Gulf done to manage retirement benefit costs?

A. Gulf has made a number of plan changes that put fixed dollar limits on the size of retiree medical and retiree death benefits. This type of limit is an effective way of capping the Company's obligations. For example, impacted retirees now must pay all of the increase in the cost of medical coverage each year, because the Company's share of the annual cost of coverage has been limited to a fixed dollar amount. The most recent plan change was the imposition of a $12,500 maximum on retiree death benefits payable to survivors of non-bargaining unit employees who retire after January 1, 2011 and who die after attaining age 65. Prior to the change, impacted employees could anticipate benefits as high as 75 percent of final base pay. In large part due to these changes that Gulf has made, the projected 2012 expense for these two retirement benefits are actually lower than they were in the prior test year.

Q. What has caused medical plan costs to increase by as much as they have since the costs were projected for the prior 2002-2003 test year?

A. Medical plan costs are increasing faster than general inflation all across the U.S. and at the Company due to factors that include:

- Price increases in provider reimbursements driven, in part, by an increase in the number of uninsured individuals and by cost shifting from the Medicare and Medicaid programs;
- Increased utilization of inpatient and outpatient care, as well as pharmaceutical therapies. These increases are driven by:
    - An aging U.S. population,
    - Increased prevalence of chronic disease,
    - Continued focus on direct consumer advertising by pharmaceutical companies, and
    - Threat of malpractice leading physicians to practice defensive medicine;
- Adoption of more complex therapies in place of lower cost treatments, increasing the intensity of care delivered;

- Technological enhancements in medical treatments, therapies and services driving greater utilization and cost; and
- Provisions in health care legislation requiring coverage improvements and introducing new fees and taxes to the health care industry.

These factors have impacted employer plans quite broadly. As shown in Schedule 1 of Exhibit AEC-1, employer health plan cost increases have averaged 7.6 percent per year from 2001 to 2012. Increases in the utility industry have been slightly higher (8.6 percent per year). Gulf's plan increases of 8.8 percent are in line with the utility industry.

Q. What has Gulf Power done to mitigate medical plan cost increases?

A. The increasing cost of health care is a national concern, and controlling costs while providing quality medical coverage will continue to be a top priority for Gulf. Since 2003, Gulf has implemented many initiatives to control health care expenses. Listed below are some examples, with more savings detail provided on Schedule 2 of Exhibit AEC-1:

- Merged Gulf's medical plan into a larger Southern Company plan to reduce plan experience fluctuations and administrative costs;
- Annually adjusted employee contributions;
- Consolidated Pharmacy Benefit Manager (PBM) services to lower vendor administrative fees;
- Successfully renegotiated the administrative services contract with the PBM several times during this period;

- Implemented numerous prescription drug purchasing and price controls for using generic drugs, mail order, etc.;
- Conducted dependent eligibility reviews and removed ineligible dependents;
- Implemented comprehensive wellness and disease management programs for employees;
- Added emphasis on employee responsibility to manage individual health care costs; and
- Applied for and received Retail Drug Subsidy (RDS) and Early Retirement Reimbursement Program (ERRP) payments from the Federal Government to help offset some of the cost increases.

Each of these changes resulted in significant savings in the year of the change as documented in Schedule 2 of Exhibit AEC-1. Most of these changes also generated ongoing savings in subsequent years, though the ongoing savings are difficult to quantify in a cumulative manner.

With these significant efforts, Gulf has been able to manage medical plan cost increases and maintain competitive health insurance benefits for its employees. As a result, Gulf's medical plan cost increases are in line with the utility industry, but slightly higher than the national average.

Q. Please summarize your testimony.

A. Gulf's benefits are reasonable for two primary reasons. Their value is generally in line with the average value of benefits offered by Fortune 500 companies and slightly below the average value for 15 other large utilities. Also, the benefits are in line with the Company's philosophy of having total benefits at the median of market.

The increase in Gulf's retirement benefit costs is primarily attributable to increases in pension expense due to losses resulting from falling interest rates and poor market performance. Nearly all pension plans experienced losses for these same reasons. Gulf's retiree medical and death benefit expenses have not increased in large part due to the benefit limitations that the Company has imposed.

Gulf has experienced health care cost increases since its last rate case that are in line with industry averages. While Gulf's cost increases are slightly higher than national averages, this is explained by industry norms. Gulf has continuously worked to manage its health care plan to control health care costs and maximize efficiencies while maintaining a competitive level of benefits for its employees.

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

MR. STONE: They had an exhibit -- actually it was two combined schedules that were labeled as Hearing ID Number 20 that I would like to have entered into the record.

CHAIRMAN GRAHAM: We will enter that into the record.

(Exhibit Number 20 admitted into the record.)

MR. STONE: I would turn it over to Mr. Melson.

MR. MELSON: And Gulf calls Richard J. McMillan.

RICHARD J. McMILLAN

was called as a witness on behalf of Gulf Power Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MELSON:

Q. Mr. McMillan, have you been sworn?

A. Yes.

Q. Would you please state your name and business address?

A. Richard J. McMillan, One Energy Place, Pensacola, Florida 32520.

Q. By whom are you employed and in what capacity?

A. Gulf Power Company. I'm Corporate Planning Manager.

Q. And you had three pieces of Direct Testimony in this docket, is that correct?

A. Yes.

Q. You prefiled Direct Testimony dated July 8th consisting of 32 pages, is that right?

A. Yes.

Q. And Supplemental Direct Testimony related to interim rates dated July 8th, 2011, consisting of three pages, is that right?

A. Yes.

Q. And Supplemental Direct Testimony filed pursuant to stipulation about considering the Crist turbine upgrades in this docket dated November 8th and consisting of seven pages, is that correct?

A. Yes.

Q. Do you have any changes or corrections to any of those three pieces of testimony?

A. No, but I would point out that the numbers in my Direct Testimony have not been update to reflect the impact of the stipulations that the Commission approved on Monday, or the impact of moving the Crist turbine upgrades from ECRC into base rates.

Q. And with that understanding, if I were to ask you the same questions today, would your answers be the same?

A. Yes.

MR. MELSON: Mr. Chairman, I'd ask that the Direct Testimony and two pieces of Supplemental Direct Testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert the Direct Testimony and the two pieces of Supplemental Direct Testimony into the record as read.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard J. McMillan
Docket No. 110138-EI
In Support of Rate Relief
Date of Filing: July 8, 2011

Q. Please state your name and business address.

A. My name is Richard J. McMillan. 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 Planning Manager.

Q. What are your responsibilities as Gulf's Corporate Planning Manager?

A. My primary responsibility is to ensure that Gulf's budgeting, forecasting, and performance measurements are accurate, effective and consistent. I also coordinate the overall planning process, including the ongoing development and maintenance of the Operations and Maintenance (O&M) and Construction Budgeting System and other financial forecasting models and projections. The Corporate Planning Department also provides decision support and financial analyses for the business units and management.

Q. Please describe your educational and professional background.

A. I graduated from Louisiana State University in 1976 with a Bachelor of

Science in Accounting. Immediately following graduation, I was employed by Gulf as an Internal Auditor. I have held various accounting positions of increasing responsibility, including Staff Internal Auditor, Staff Financial Analyst, Staff Accountant, Coordinator of Internal Accounting Controls, Supervisor of Financial Planning, General Accounting Manager, and Assistant Comptroller. I have held my current position since January 2006. Also, during my employment, I graduated from the University of West Florida in 1983 with a Master of Business Administration.

Q. What is the purpose of your testimony?

A. Using the financial forecast discussed by Gulf Witness Buck 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. I also discuss the adjustments related to the Unit Power Sales from Scherer Unit 3; present and support Gulf's O&M expense Benchmark calculations; present and support the general plant capital additions budget and investment; and provide an overview of Southern Company Services (SCS) and the services and benefits Gulf receives from the service company.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit RJM-1, Schedules 1 through 20. Exhibit RJM-1 was prepared under my supervision and direction, and the information contained in that 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 my Exhibit RJM-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 RJM-1, Schedule 2, entitled "13-Month Average Rate Base for the Period Ended December 31, 2012," reflects Gulf's test year rate base. Column 1 is calculated based on the budget data presented on Schedules 7 and 9 of Mr. Buck's Exhibit WGB-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 includes the Plant Scherer Unit Power Sales (UPS) adjustments, which I will address in more detail 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. Please explain the rate base regulatory adjustments in column 2 of Schedule 2.

A. These adjustments are listed on page 2 of Schedule 2 of Exhibit RJM-1. Adjustments 1, 2, 4, 5, and 11 are to remove the amounts being recovered through the Environmental Cost Recovery Clause (ECRC) and the Energy Conservation Cost Recovery (ECCR) Clause. The investments which are being recovered through the adjustment clauses must be excluded in developing the rate base used to establish Gulf's base rates.

Adjustments 3 and 6 are to remove the plant-in-service and accumulated depreciation amounts related to the implementation of Financial Accounting Standards (FAS) 143, Accounting for Asset Retirement Obligations (AROs). This accounting standard required 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 FAS 143 in the working capital adjustments as shown in 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 the Commission) Rule 25-14.014, which requires that the application of FAS 143 shall be revenue neutral.

Adjustments 7 and 8 are the accumulated reserve impact of proposed changes in depreciation and amortization related to Gulf's implementation of the new Advanced Metering Infrastructure (AMI) meters. The implementation is now scheduled to be essentially complete by the end of the test year. Gulf is therefore requesting to amortize the remaining balance of the old meters over four years (adjustment 7) and to establish the service lives related to the new meters at 15 years (adjustment 8). The AMI adjustments to depreciation expense and accumulated reserve were provided to me by Gulf Witness Erickson and are discussed in her testimony.

Adjustment 9 is to include in rate base the land and other deferred charges Gulf has incurred related to its deferred nuclear site selection costs and to discontinue deferring these costs. These costs have been deferred in accordance with Florida Statute 366.93 and include all deferred costs, including a deferred return, through the end of 2011. As discussed by Gulf Witness Burroughs in his testimony, the site will be available for any future generation needs, and the land purchases will be completed in 2012. In deciding to pursue consideration of nuclear generation, Gulf relied on the recovery provided by this statute. Gulf believes that nuclear is a viable option that benefits customers under a range of scenarios. The Northwest Florida site is the only site in our service area suitable for nuclear generation. The purchase of this site is thus necessary to allow Gulf to preserve a nuclear option for its customers. The Northwest Florida site has all the attributes – water, rail and gas – necessary for other forms of generation. Gulf is therefore requesting to include the costs incurred to date in rate base since the site will be available and considered for any future nuclear or non-nuclear generation needs.

As prescribed by Florida Statute 366.93, carrying charges cease once the site selection costs are placed in rate base. By placing these costs in rate base at this time, the Company will discontinue deferring a return on these amounts, thereby avoiding additional costs that would otherwise accumulate and become part of the site costs. This treatment will minimize the cost of any plant that is ultimately constructed on the site. It also recognizes that obtaining suitable generation sites necessary to keep open all cost-effective generation options is a prudent and necessary cost of providing reliable utility service at reasonable rates.

Adjustment 10 is for the removal of the interest bearing construction work in progress (CWIP) included in the forecast. Since interest bearing projects in CWIP are eligible for Allowance for Funds Used During Construction (AFUDC), they are removed from rate base.

Adjustment 12 represents the working capital adjustments, which are detailed on Schedule 3.

Q. Please explain Schedule 3, entitled "13-Month Average Working Capital for the Period Ended December 31, 2012."

A. Gulf has computed the test year working capital requirement utilizing the balance sheet approach in accordance with this Commission's prior policy and practices. All items on the balance sheet which are not included in Net Utility Plant or Capital Structure were considered in developing working capital. These items are summarized at the top of the schedule and result in $179,814,000 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, the ARO regulatory assets and liabilities I discussed previously, and the deferred nuclear site costs. I have also adjusted working capital to reflect the impact of the increase in the property damage reserve accrual discussed by Ms. Erickson in her testimony, the unamortized rate case expenses related to this rate filing, and a reduction in pension and other post retirement accruals to reflect updated information that became available after the 2011 budget was finalized.

The other adjustments noted in Schedule 3 remove the assets and liabilities related to Gulf's fuel hedging under FAS 133, Accounting for Derivative Instruments and Hedging Activities, which are ultimately recovered through the Fuel Cost Recovery (FCR) Clause, and remove the minimum pension funding requirements under FAS 158, Employers' Accounting for Defined Benefit Pension and Other Post Retirement Plans, 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 FAS 133, FAS 158, 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.

The net of all regulatory adjustments to total working capital is $16,081,000, which is shown in column 2 on page 1 of Schedule 2 as adjustment 12. The Plant Scherer UPS working capital adjustment is shown at the bottom of Schedule 3. This adjustment excludes the amounts directly assigned to UPS for fuel stock, materials and supplies, and prepayments, plus the allocated amounts for other working capital consistent with the treatment in prior rate proceedings. The total system adjusted working capital of $155,044,000 (column 4, page 1 of Schedule 2) resulted in jurisdictional adjusted working capital of $150,609,000 (column 6, page 1 of Schedule 2) as derived by Mr. O'Sheasy in the cost-of-service study.

Q. Were there any other adjustments made to rate base in Gulf's last rate case filed in Docket No. 010949-EI that you are not making in this case?

A. Yes. There were several adjustments made in the last case which are not applicable in this case. These include adjustments related to appliance sales, test year depreciation study impacts, house power panels, security measures, and the unamortized loss on the sale of railcars. The circumstances giving rise to the need for these adjustments in Gulf's last rate case do not apply to the 2012 test year. The rate base adjustments, including the adjustments not made, are listed in MFR B-2.

Q. What is the total jurisdictional rate base for the 2012 test year after all the appropriate adjustments have been made?

A. As shown on page 1 of Schedule 2 of Exhibit RJM-1, the total jurisdictional adjusted rate base is $1,676,004,000. 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. Now moving to Net Operating Income (NOI), please explain Exhibit RJM-1, Schedule 4 entitled "Net Operating Income for the Twelve Months Ended December 31, 2012."

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 2012 budget data from Schedule 8 of Mr. Buck's Exhibit WGB-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 on page 1 of Schedule 4 sets forth the UPS amounts. I will discuss the UPS adjustments and calculations later in my testimony. The jurisidictional 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 16, 28, 29, 32, and 35) related to the retail cost recovery clauses are included on pages 2 and 3 of Schedule 3. Additional details supporting each cost recovery clause adjustment are provided on Schedules 5 through 8. 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 retail amounts for each cost recovery clause.

Q. Please explain the franchise fee and gross receipts adjustments 7, 8, 33, and 36 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 last rate case and are separately calculated and shown on the customer's bill.

Q. Please explain adjustments 5 and 25 related to additional collection efforts.

A. The adjustments are necessary to reflect the results of a concerted effort to focus more on collection activities by Gulf's field service representatives (FSRs). As discussed by Gulf Witness Neyman, the FSRs who support this effort were included in the test year budget, but the budget did not reflect the expected increase in collection and reconnection fees (adjustment 5) and an estimated reduction in uncollectible expenses (adjustment 25) resulting from these efforts.

Q. Please explain adjustment 17 related to marketing support activities and adjustment 18 related to wholesale sales activities.

A. Expenses related to marketing support activities (adjustment 17) 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 18) 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 adjustment 19 and 20 related to institutional advertising and economic development expenses.

A. Consistent with prior Commission decisions, adjustment 19 removes the test year amount of institutional or image building advertising. All other advertising is either recovered in the energy conservation cost recovery clause or meets the criteria for recovery in base rates and is included in the O&M expenses supported by Ms. Neyman in this proceeding.

Adjustment 20 removes 5 percent of the 2012 test year expenses related to economic development expenses. This treatment is also consistent with the Commission's decision in Gulf's last rate case, and Ms. Neyman will support the reasonableness of the test year amount.

Q. Please explain adjustments 21, 23, and 34.

A. These adjustments remove the expenses related to management financial planning services (adjustment 21) and the Tallahassee liaison expenses (adjustments 23 and 34), consistent with the Commission's decision in Gulf's last rate case.

Q. Please explain adjustment 22 related to the property insurance reserve accrual.

A. Gulf is requesting an increase to the annual property insurance reserve accrual from the current approved amount of $3.5 million to $6.8 million based on an updated storm damage study. The need for this increase and the amount of the accrual is supported by Ms. Erickson in her testimony.

Q. Please explain adjustment 24 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 $2,800,000, as discussed by Ms. Erickson. We are 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 explain adjustment 27 related to Pensions and Other Post Retirement Benefits.

A. This adjustment is to reflect the latest pension and other post retirement estimated costs for the test year. This reduction in costs from the 2011 budget estimate is based on the latest actuarial estimates available at the time of the filing and includes the actual 2010 financial results, which were not available at the time the financial forecast was prepared.

Q. Please explain adjustments 6, 26, 30 and 31related to the installation of AMI meters.

A. These adjustments are to adjust the test year to reflect additional revenues, a reduction in customer accounting expenses, and an increase in depreciation expense to reflect the full implementation of new AMI meters by the end of 2012. These adjustments are needed to adjust the Company budget for these additional items not included in the financial forecast I used to prepare the 2012 test year data.

Adjustment 6 reflects an estimated increase in revenues related to improved meter accuracy of the new digital meters, and adjustment 26 is to reduce customer accounting expense to reflect a reduction in transportation costs for meter reading activities. These adjustments were provided to me and will be addressed by Ms. Neyman.

Adjustments 30 and 31 are related to the accelerated implementation schedule related to AMI meters. Since the AMI meter replacement schedule has been accelerated and will be completed during the test year, we need to increase depreciation to account for the amortization of the remaining old meters that will be retired when removed. Adjustment 30 reflects a four year amortization of the remaining old meters. Gulf is also requesting an increase in depreciation expense to reflect an estimated 15 year life for the new meters in adjustment 31. These adjustments were provided to me by Ms. Erickson and are discussed in her testimony.

Q. Please explain adjustment 37 to taxes other than income taxes.

A. Adjustment 37 is required to remove the FPSC assessment fees that are associated with the retail revenues and franchise fee revenues removed in adjustments 1 through 7. Schedule 9 shows the calculation of this adjustment.

Q. Please explain adjustment 38 to income taxes on Schedule 4.

A. This adjustment is required to reflect the federal and state income tax effects of adjustments 1 through 37. Schedule 10 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 39 on Schedule 4 reflects the tax effect of synchronizing interest expense to rate base, and Schedule 11 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 Schedule 12, and total company interest expense was taken from the projected income statement provided to me by Mr. Buck (Exhibit WGB-1, Schedule 8).

Q. Did the Commission make any other NOI adjustments in the last rate case that are applicable in this case?

A. No. The other Commission adjustments to NOI in the last rate case related primarily to expense amounts forecasted for the 2002/2003 test year. These adjustments were specific to the forecast amounts for the prior test year and are not applicable to the forecasts for the 2012 test year.

Q. In Gulf's last case the Commission made an adjustment for hiring lag, but you have not included one in your request. Why is an adjustment for hiring lag not appropriate for the 2012 test year?

A. As discussed by several Company witnesses, Gulf's budget assumes a full work force complement for the test year. As shown on Schedule 20 of my exhibit, by year end 2010, due to extraordinary efforts to reduce costs and defer a rate case, Gulf's work force had declined to a level of 1,330 full time equivalent (FTE) positions. The work force included in Gulf's 2012 test year is 1,489 FTEs. Those 159 additional FTEs are necessary and appropriate for Gulf's provision of service. Over 95 percent (152 FTEs) are justified in the testimony of Gulf Witnesses Neyman, Moore, Caldwell and Grove, who address the functional areas in which these positions are budgeted. As shown on Schedule 20, 31 of the additional FTEs are employees whose salary will be recovered through the ECCR and ECRC clauses, and the salaries of an additional 42 FTEs are capitalized as part of the capital additions budget. Therefore, the salaries and benefits for these 73 FTEs do not impact the test year O&M request.

As these witnesses explain, the Company expects to be at or close to a full complement in 2012. More importantly, the total O&M dollars requested are needed to continue to meet our customers' expected service levels. If there is a lag when hiring new employees, the Company often will incur higher overtime pay for other employees or will hire temporary labor or use contract labor to complete the duties of the vacant position. As discussed below, if the funds resulting from temporary vacancies are not spent on labor, they will likely be redeployed to meet other high priority needs.

The Company believes a hiring lag adjustment is inappropriate for several reasons. First, such an adjustment assumes that if a position is not filled, the associated funds will not be spent. Second, a hiring lag adjustment assumes that labor costs should be looked at in isolation. Both of these assumptions ignore the real process that managers use in evaluating and prioritizing the use of their resources. When faced with an unexpected cost or changing circumstances, resources can and will be redeployed from one budget category to another to meet customers' needs and provide reliable electric service to our customers. The budget is a planning tool, but changing conditions can and will require that resources budgeted in one activity or cost category be redeployed as actual conditions require. It is therefore unlikely that any funds available from unfilled positions would result in lower total O&M expenses.

Q. Please summarize Gulf's adjusted O&M request included in the 2012 test year.

A. The Company's total test year adjusted O&M request of $288,474,000 is reasonable, prudent and necessary to provide reliable electric service to our customers.

Q. What is the total jurisdictional NOI for the 2012 test year after all the appropriate adjustments have been made?

A. Gulf's jurisdictional NOI for 2012 is $60,955,000.

III. JURISDICTIONAL CAPITAL STRUCTURE

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

A. Yes. Schedule 12, page 1, of Exhibit RJM-1 shows the jurisdictional 13-month average amounts of each class of capital for the test year ended December 31, 2012. 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. Pages 3 and 4 show the calculation of the weighted cost rates for long-term debt, and page 5 shows the calculation of the weighted cost rate for preference stock.

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

A. The cost rates for preference stock and long-term debt reflect their embedded 13-month average costs as calculated on pages 3 through 5 of Schedule 12. The projected interest rate assumptions used in the financial forecast are shown in MFR F-8. The assumptions used in the forecast for new issues were provided by SCS Finance and were based on the September 2010 market forecast by Moody's Analytics (formerly known as Moody's Economy.com). The customer deposit cost rate of 6.00 percent was based on the effective rate for the 2006 through 2009 historic period. The cost for investment tax credits of 8.45 percent was calculated in accordance with current IRS regulations and past 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 12, I started with the 13-month average total company capital structure by class of capital. These total company amounts were calculated based on the projected balances for each item in the capital structure from the balance sheet provided to me by Mr. Buck (Exhibit WGB-1, Schedule 7). In columns 2 through 5 and 7, I have identified five adjustments which were removed from specific classes of capital. The remaining adjustments required to reconcile the rate base and capital structure were made on a pro rata basis as shown in column 10.

Q. Please explain the five items for which you have made adjustments to specific classes of capital.

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. The third 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 fourth item 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 7, is the removal of the UPS capital structure amounts. The UPS capital structure adjustments are consistent with past Commission decisions to remove all investments and expenses related to Plant Scherer from retail jurisdictional calculations since this plant's output is being sold to non-territorial wholesale customers. I specifically identified the deferred taxes and investment tax credits related to Plant Scherer and then allocated the remaining UPS investment over the other external sources of funds.

Q. Why is it appropriate to make the remaining adjustments 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 12, result in a cost of capital of 7.05 percent based on a requested return on equity of 11.7 percent, which is supported in the testimony of Gulf Witness Dr. Vander Weide.

IV. REVENUE DEFICIENCY

Q. Based on the 2012 jurisdictional adjusted amounts for rate base of $1,676,004,000, NOI of $60,955,000, and the test year cost of capital of 7.05 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 3.64 percent and the achieved return on common equity will be 2.83 percent for the test year, as shown on Schedule 13 of Exhibit RJM-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 3.64 percent and the test year cost of capital of 7.05 percent?

A. Yes. The revenue deficiency is $93,504,000, as calculated on Schedule 14, which references the schedule where each figure was derived. Schedule 15 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 7.05 percent.

V. UPS ADJUSTMENTS

Q. You have previously mentioned that you are supporting the Plant Scherer UPS adjustments 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 UPS amounts, which have been identified on Schedules 2, 4, and 12 of Exhibit RJM-1, were computed in the same manner as they were in Gulf's last two rate cases. The UPS rate base and NOI adjustments reflect the removal of all amounts related to Plant Scherer. These adjustments include all Scherer investment and expenses, including allocated amounts of general plant, working capital, and administrative and general expenses consistent with prior Commission treatment.

VI. 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 16 of Exhibit RJM-1 shows the functional summary for the test year. As shown on Schedule 16, the Company's total adjusted O&M of $288,474,000 for the test year is $38,169,000 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. These are the adjusted 2002/2003 test year O&M expenses allowed in Gulf's last rate case. The derivation of the 2002/2003 allowed amounts by function is included in MFR C-39 and Schedule 17 of Exhibit RJM-1. The adjustments in columns 4 through 7 include the system amount of the Company and Commission adjustments, and column 8 reflects the system allowed O&M by function. This amount is included in column 3 of Schedule 16 of my Exhibit.

The second step is to escalate these base year amounts by the compound multipliers noted in column 4 of Schedule 16 in order to derive the Test Year Benchmark amounts included in column 5.

The third step is to calculate the adjusted 2012 test year O&M expense request by function included in column 6 of Schedule 16. The derivation of these figures is shown on MFR C-38 and Schedule 18 of Exhibit RJM-1.

The final step is to compare the test year requested O&M in column 6 of Schedule 16 to the Test Year Benchmark in column 5 in order to calculate the variance shown in column 7.

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.

Q. What types of factors can cause test year expenses to exceed the Benchmark for a particular functional area?

A. Benchmark variances may be explained by a variety of factors. For example, an O&M increase due to the cost of compliance with a new regulatory requirement would be totally unrelated to either customer growth or inflation. Additionally, the CPI used to calculate the Benchmark is a measure of increases in the cost of a wide variety of consumer items. The cost of specific items relevant to the utility industry, such as the cost of steel used in construction or the cost of health care, may have escalated at a rate much higher than the CPI. As shown in Schedule 16 of Exhibit RJM-1, the Company's total adjusted O&M expense of $288,474,000 is $38,169,000 above the Benchmark. The witnesses for each functional area that had O&M expenses over its Benchmark explain the reasons for that variance.

VII. GENERAL PLANT INVESTMENT

Q. Schedule 2 shows a total of $2.6 billion of plant-in-service investment in Gulf's 2012 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 $157,510,000 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 by Mr. Buck.

Q. What is Gulf's projected General Plant capital additions budget for 2011 and 2012?

A. As shown on Schedule 19 of my Exhibit, Gulf's General Plant capital additions budget for 2011 is $11,836,000 and for 2012 is $15,835,000. The major items included in the 2012 test year are:

• Automobiles, Trucks and Equipment	$2,563,000
• Pine Forest Building/ New Office Space	$8,795,000
• Office Facility Capital Items	$ 926,000
• IT Projects	$1,791,000
• Enterprise Solutions/GLSCAPE	$ 747,000
• Tools and Test Equipment	$ 750,000
• Other Projects	$ 263,000

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 Corporate area. Gulf Witness Moore discusses the test year amount for automobiles, trucks and equipment since this investment primarily supports the distribution and transmission business units. The general plant requests are included in the capital budget review and approval by the executives.

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

A. As discussed by Mr. Buck, Corporate Planning requires detailed explanations 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.

VIII. SOUTHERN COMPANY SERVICES

Q. Please provide an overview of Southern Company Services and its relationship to Gulf.

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

All services provided by SCS are provided at cost. Costs are determined and billed in two ways. Costs are directly assigned to the Company receiving the services when possible. Where direct assignment is not possible, costs are allocated among the subsidiaries receiving services based on a pre-approved cost allocator appropriate for the type of services performed. Typical allocators include employees, customers, loads, generating plant capacity, and financial factors. The methodology for developing the allocators is the same methodology used at the time of Gulf's last rate case. The allocators are approved by SCS and by management of the applicable operating companies and are updated annually based on objective historical information.

Q. What benefits does Gulf enjoy by obtaining these services from SCS?

A. Gulf and its customers receive several benefits. The existence of SCS avoids duplication of personnel in the various operating companies, provides economies of scale in purchasing and other activities, and enables Gulf to draw on shared experience from a centralized pool of professional talent. As one of the smaller operating companies, access to these shared resources is particularly valuable to Gulf, which otherwise would have to employ, for example, a group of generation planning personnel who might not be fully utilized on a continuous basis.

IX. PLANT CRIST SCRUBBER PROJECT – TURBINE UPGRADES

Q. How have the turbine upgrades related to the Crist Scrubber Project been treated in the Company's request for base rate relief in this filing?

A. Gulf has excluded the turbine upgrades to Crist Units 6 and 7 included in the Crist Scrubber Project from rate base and NOI in the ECRC adjustments included in my Schedules 2 and 4. These turbine upgrades were approved for recovery through the ECRC and have been properly removed in the adjustments to remove the investment and expenses for the recovery clauses. A portion of the turbine upgrades related to Unit 7 were completed in 2009, and the remaining turbine upgrade costs for Units 6 and 7 are scheduled to be placed in service in 2012. Gulf believes these costs are appropriate for recovery through the ECRC, and will request and justify recovery of these costs in its 2011 clause filing. Accordingly, Gulf has removed these costs from rate base in the ECRC adjustments on Schedules 2 and 4.

Q. If the Commission did not allow recovery of the full Crist Scrubber Project costs through the ECRC, would any action be required to address those costs in this rate proceeding?

A. Yes. In the event any portion of the Crist scrubber costs were not allowed for recovery through the ECRC, the adjustment I have made to exclude those costs from rate base would have to be reversed in order to permit their recovery through base rates. These projects are either in service already or will go into service during the test year and will be used and useful in providing service to customers. The Company is therefore entitled to recover these costs either through the clause or in base rates.

X. SUMMARY

Q. Please summarize your testimony.

A. Gulf's test year rate base is $1,676,004,000. The total system rate base amounts for 2012 were based upon the financial forecast provided to me by Mr. Buck. This amount is adjusted to remove the Plant Scherer UPS investment and make the other regulatory adjustments as shown on Schedule 2 of my exhibit. Mr. O'Sheasy then jurisdictionalized this adjusted amount in the cost of service study, which resulted in the jurisdictional adjusted amount reflected in the last column of Schedule 2. $1,676,004,000 represents the retail base rate investments that are used and useful in providing service to Gulf's retail customers during the test year and, as described by other witnesses, are reasonable and prudent.

Gulf's total jurisdictional NOI for the 2012 test year is $60,955,000. Like rate base, the calculation of NOI also began with the 2012 financial forecast provided to me by Mr. Buck. I then made the appropriate Plant Scherer UPS and regulatory adjustments as shown on Schedule 4 of my exhibit, and Mr. O'Sheasy made the jurisdictional allocations in the cost of service study. The O&M expenses included in the calculation of NOI are supported by witnesses from each functional area. I also calculated the

O&M Benchmark variance for the total company and for each function. Where the projected expenses for a particular functional area exceed the O&M Benchmark, the functional witnesses explain the reasons for that variance. 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.

I also developed the jurisdictional adjusted capital structure, and I calculated a weighted cost of capital of 7.05 percent for the test year. This cost is based on Gulf's actual or projected cost of each source of capital and a required return on equity of 11.7 percent as recommended by Dr. Vander Weide. This combination of jurisdictional adjusted rate base, NOI and weighted average cost of capital shows that Gulf requires a retail base revenue increase of $93,504,000 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.

I also discuss SCS and the associated benefits Gulf receives, including the numerous professional and technical services which are provided to Gulf at cost. Gulf's ability to obtain these services from SCS benefits our customers in a variety of ways, including cost savings due to economies of scale and access to the shared experience of a group of highly trained professionals that it would be impractical to try to replicate at the Company level.

Q. Mr. McMillan, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Supplemental Direct Testimony of
Richard J. McMillan
In Support of Interim Rate Relief
Docket No. 110138-EI
Date of Filing: July 8, 2011

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

A. My name is Richard J. McMillan, and my business address is One Energy Place, Pensacola, Florida 32520. I am employed by Gulf Power Company (Gulf or the Company) as Corporate Planning Manager.

Q. Are you the same Richard McMillan who has prefiled direct testimony in this docket in connection with Gulf Power Company's request for rate relief?

A. Yes.

Q. What is the purpose of this supplemental direct testimony?

A. The purpose of this supplemental direct testimony is to support the Company's request for interim rate relief.

Q. Are you sponsoring any Minimum Filing Requirements (MFRs) related to the request for interim rate relief?

A. Yes. These are listed in Schedule 1 of my Exhibit RJM-2. The information contained in these MFRs in true and correct to the best of my knowledge and belief.

Q. What interim relief is Gulf requesting in this case?

A. Gulf is requesting an interim rate increase of $38,549,000 calculated in accordance with Section 366.071(5), Florida Statutes. The calculation of interim relief shown on MFR G-1 was based upon the historic twelve-month period ending March 31, 2011, and represents the additional revenues Gulf needs to achieve a 10.75 percent return on equity (the earnings floor approved in the Company's last rate case in Docket No. 010949-EI). Gulf's jurisdictional adjusted return on equity for the twelve months ended March 31, 2011 was 6.82 percent, and is projected to continue to decline without immediate rate relief.

Q. In calculating the interim rate request, did Gulf apply appropriate adjustments consistent with those used in the last rate case?

A. Yes. Those adjustments are shown on MFR Schedules G-3, G-5, and G-9. The adjustments are discussed in more detail in my direct testimony.

Q. Did Gulf annualize any rate changes that occurred during the 12-month period used for calculating the interim rate request?

A. No. There were no such base rate changes during that period.

Q. How does Gulf propose to secure any potential refund of interim rates?

A. Gulf requests that the Commission authorize Gulf to use a corporate undertaking to secure any potential refund obligation. This is a lower cost option than posting a bond, and Gulf has the financial resources to support such an undertaking.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Supplemental Direct Testimony and Exhibit of
Richard J. McMillan
Docket No. 110138-EI
In Support of Rate Relief
Date of Filing: November 8, 2011

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

A. My name is Richard J. McMillan. My business address is One Energy Place, Pensacola, Florida 32520, and I am employed by Gulf Power Company (Gulf or the Company) as Corporate Planning Manager.

Q. Did you file direct and rebuttal testimony in this docket?

A. Yes.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to address the extent to which the investment and expenses associated with Gulf's Crist Unit 6 and 7 turbine upgrade projects should be included in the rate base and net operating income (NOI) that are used to calculate Gulf's revenue requirements and base rates in this proceeding.

Q. Do you have any exhibits to this supplemental direct testimony?

A. Yes. I am sponsoring Exhibit RJM-3, consisting of two schedules. This exhibit was prepared under my direction and supervision and the information contained in these schedules is true and correct to the best of my knowledge and belief.

Q. Please briefly describe the turbine upgrade projects.

A. The turbine upgrades for Crist Units 6 and 7 are being installed as part of the Company's implementation of the Plant Crist Scrubber Project. The turbine upgrades are designed to offset the increased station service requirements (internally consumed electricity) associated with the scrubber installation and to increase the overall efficiency of the scrubbed units. The turbine upgrades include:

- Crist 7 High Pressure/Intermediate Pressure (HP/IP) upgrades completed in January 2010;
- Crist 6 HP/IP upgrades scheduled for completion in May 2012; and
- Crist 7 Lower Pressure (LP) upgrades scheduled for completion in December 2012.

Q. Why are you filing supplemental direct testimony at this time?

A. At the time my direct testimony was filed in July 2011, the costs of the Crist 7 HP/IP upgrades were being recovered through the Environmental Cost Recovery Clause (ECRC) and Gulf was planning to begin seeking recovery of the other turbine upgrade costs through the 2012 ECRC factors. As a result, I made adjustments to the 2012 test year rate base and NOI to exclude the costs of the projects from our base rate request. I also noted that if any portion of these costs were not allowed for recovery through the ECRC, then Gulf should be allowed to recover those costs through base rates.

After my direct testimony was filed, a dispute arose in the ECRC docket as to the appropriateness of recovering the turbine upgrades through the ECRC. In order to resolve that dispute, Gulf and the other parties to the ECRC docket and this docket stipulated that recovery of these costs through the ECRC would be discontinued on a prospective basis and that prospective recovery should be provided through the base rates to be established in this docket. This stipulation, which was approved by the Commission on November 1, 2011, also established a timetable for supplemental testimony to be filed by the parties to this docket.

Q. Please summarize Gulf's proposals for how the turbine upgrade costs should be handled in this base rate proceeding.

A. Gulf has a primary proposal and an alternative proposal. Although they differ in their details, each proposal is designed to implement the following two principles in a manner that provides fair ratemaking treatment to Gulf's customers and to the Company:

- Ensure that the dollars collected from ratepayers during 2012 equal the amount that would be collected if the turbine upgrade projects were included in Gulf's 2012 rate base at their 13-month average test year balance, and related depreciation expenses were included at their projected amount for the 2012 test year.
- Ensure that Gulf is able to recover the full costs of these projects (both capital and expenses) beginning in 2013, after all three projects have been placed in service.

Q. Please describe Gulf's primary proposal.

A. Gulf's primary proposal is to include all three turbine upgrade projects in rate base and NOI as if they had been in service for the entire year. This would set base rates for 2012 and later years at a level that includes the full cost of the projects. This would result in Gulf recovering incrementally more revenues through base rates in 2012 than if the projects are included in rate base and NOI at their actual 2012 projected amounts. To keep customers whole, Gulf proposes to credit the customers for the full amount of these incremental revenues by reducing the ECRC cost recovery factors for 2012 by a like dollar amount, to take effect on the same date that rates take effect in this docket.

Q. What is Gulf's alternative proposal?

A. Gulf's alternative proposal is to set base rates for 2012 by including each of these projects in rate base at their 13-month average balance and including the actual 2012 projected level of expenses in the calculation of NOI. Gulf then proposes that the Commission, in this docket, approve a subsequent year adjustment to Gulf's base rates beginning January 1, 2013, to reflect the full annual cost of these projects, which by then will be used and useful in providing electric service to Gulf's customers.

Q. Referring to Schedule 1 of Exhibit RJM-3, please discuss the rate impact of these alternative proposals.

A. Column (1) on page 1 shows the 2012 revenue requirement impact if the projects are included in rate base and NOI at their actual 13-month average balance for 2012. This amount is $3,768,000.

Column (2) on page 1 calculates the annual revenue requirement impact of the projects for an entire year. This amount is $8,104,000. As shown in column (3), this is a difference of $4,336,000 compared to using the test year average amounts.

Under Gulf's primary proposal, the base rates established in this case would include the $8,104,000 revenue requirement. Because these rates will be in effect for 81% of the year (March 12 to December 31), Gulf would collect $3,512,000 more from customers in base rates than if the revenue requirement was based on the test year average amounts. This excess is the amount that Gulf proposes to credit back to customers during 2012 by adjusting the ECRC factor downward effective on the same date as the new base rates.

Under Gulf's alternative proposal, the rates established in this case for 2012 would include only the $3,768,000 revenue requirement, but the Commission would approve a subsequent year adjustment, to take effect January 1, 2013, to increase base rates by an additional $4,336,000 to cover the full annualized cost of the projects.

Q. Is the impact to customers and Gulf of these two alternative proposals the same?

A. Yes. In each case they result in customers paying total rates (base rates plus clauses) in 2012 as if the turbine upgrade projects had been included in rate base at their 13-month average balance, and expenses included in NOI at their actual 2012 amounts. In each case, they result in Gulf receiving total rates beginning in 2013 that appropriately reflect the full cost of those projects.

Q. If the effect on Gulf and its customers is the same, why does Gulf prefer its primary proposal to its alternative?

A. Gulf prefers the primary proposal because it provides additional base rate stability by avoiding a first base rate increase at the conclusion of this proceeding and a second base rate increase in January 2013. Gulf's customers are accustomed to infrequent changes in base rates, while they are accustomed to more frequent changes in the clause factors.

Q. Why shouldn't the Commission consider simply including actual 2012 expenses in NOI and an actual 13-month average balance in rate base, and making no further allowance for the fact that the projects will be completed in 2012?

A. Unless it makes some provision to include the full cost of these projects in rates in 2013 and beyond, the Commission would fail to recognize that Gulf will have incurred the full costs of, and customers will be receiving the full benefits from, all three of these projects by 2013. These projects will provide significant fuel and capacity cost savings to our customers beginning on their respective in-service dates. Customers are already receiving the fuel clause and capacity clause savings from the Crist 7 HP/IP upgrades that were completed in January 2010. By 2013, customers will be receiving the full savings from all three of the projects. As shown on Schedule 2 of Exhibit RJM-3, the estimated savings in every year exceed the annual revenue requirement of these projects. It is only fair that, beginning in 2013, Gulf should be allowed to recover the full cost of these investments from which customers will be receiving the full benefits.

Q. What if the Commission rejects Gulf's primary and alternative proposals, and sets rates based on the 13-month average balance of these projects in 2012?

A. In order to recover its cost of providing service, Gulf would be forced to consider filing a separate limited proceeding during 2012 to request that these costs be included in rates beginning in January 2013. Such an additional proceeding would not be an efficient use of the time and resources of Gulf, the Commission, and the intervenors, when the issues can be fully dealt with in this docket. Further, customers should not be asked to bear the costs of such an unnecessary, additional proceeding.

Q. Mr. McMillan, does this conclude your supplemental direct testimony?

A. Yes.

BY MR. MELSON:

Q. And I believe you had three exhibits, Exhibit RJM-1 to your Direct Testimony, Exhibit RJM-2 to your First Supplemental Testimony, and Exhibit RJM-3 to your Second Supplemental Testimony, is that correct?

A. Yes.

Q. And Schedule 1 of RJM-1 lists the MFR schedules that you were sponsoring or co-sponsoring, is that right?

A. Yes.

Q. With the understanding that the exhibits to your Direct Testimony have not been updated to reflect the effect of the stipulations or the Crist turbine upgrades, do you have any changes or corrections to those exhibits.

A. No.

MR. MELSON: And, Mr. Chairman, just for information, those are on Pages 8 and 9 of the exhibit list. They are 21, 22, and 23.

CHAIRMAN GRAHAM: Dually noted.

BY MR. MELSON:

Q. Mr. McMillan, could you please briefly summarize your testimony?

A. Yes. Good afternoon Commissioners. My Direct Testimony pulls together the information from all of our previous witnesses about the company's investments, our expenses, and our cost of capital. Based on that information, I calculate Gulf's jurisdictional adjusted rate base, net operating income, and weighted average cost of capital. Finally, I calculate the resulting revenue deficiency which represents the amount of the base rate increase that we were requesting in this case.

Let me begin with rate base. Gulf's test year jurisdictional adjusted rate base represents the investments that are used and useful in providing service to Gulf's retail customers during the test year. As described by Gulf's witnesses, these investments are reasonable and prudent.

To develop the retail rate base, I began with unadjusted total system amounts per Mr. Buck's financial forecast. I then made the appropriate regulatory adjustments, including an adjustment to remove the investment in Plant Scherer, which is used to make unit power sales to certain wholesale customers. Mr. O'Sheasy then took my adjusted investment figures and performed a cost-of-service study to allocate them between retail costs, which will be recovered in this case, and territorial wholesale costs which are not regulated by this Commission.

Next, I calculated Gulf's jurisdictional net operating income, or NOI. This is the amount of operating income from base rates that Gulf is projected to earn during the test year. The projected level of test year expense included in my NOI calculation is reasonable and necessary to continue to provide reliable electric service to our customers, and it is also representative of the level of expenses that will be incurred in the future.

Like rate base, the calculation of NOI began with Mr. Buck's 2012 financial forecast. I then made the appropriate Plant Scherer and other regulatory adjustments, and Mr. O'Sheasy made the jurisdictional allocations in the cost-of-service study.

Next, I developed Gulf's jurisdictional adjusted capital structure and calculated our weighted cost of capital based on Gulf's actual and projected costs for each source of capital, including a required return on equity of 11.7 percent as recommended by Doctor Vander Weide.

Based on the rate base, NOI, and cost of capital figures, I calculated a retail base revenue deficiency of $93.5 million. The impact of the stipulations approved by the Commission on Monday reduces this amount to 90.3 million. This is the amount of additional retail revenues required to enable Gulf to fund the investment and expenses needed to continue to provide safe, efficient, and reliable service to our customers. This figure does not include the effect of moving the Crist turbine upgrade projects from the environmental cost-recovery clause into base rates.

I also filed supplemental testimony which sets forth two alternative proposals for Gulf to recover the cost of three turbine upgrade projects at our Crist generating plant. One of these projects is already in service and two will go into service during 2012. Each of these projects will provide fuel and capacity cost savings to our customers for many years. The annualized revenue requirement of these projects is $8 million. My proposed ratemaking alternatives are designed to move this amount from ECRC into base rates and allow Gulf to recover the full cost of these projects beginning in 2013 when they are providing savings to our customers.

That concludes my summary.

MR. MELSON: Gulf tenders Mr. McMillan for cross.

CHAIRMAN GRAHAM: Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q. Mr. McMillan, I'm Joe McGlothlin with the Office of Public Counsel. I have some questions about your prefiled testimony. First, look at Page 5 of your first Direct Testimony. Not the supplemental, but the original.

A. All right.

Q. Beginning at Line 9 on Page 5, you describe your proposed treatment of the North Escambia site, do you not?

A. Yes.

Q. And you refer there to land and other deferred charges, do you not?

A. Excuse me, what did you say?

Q. You refer to both the land and also to certain as you describe them deferred charges?

A. That's correct.

Q. Do those deferred charges relate to the tests and evaluations and other selection costs incurred in deciding to purchase the North Escambia site?

A. Yes. It includes some preliminary survey site selection type costs and a deferred return.

Q. And then further into the paragraph you say these costs have been deferred in accordance with Florida Statute 366.93, and that is the statute that authorizes utilities to seek advanced recovery of certain costs of, among other things, nuclear units, correct?

A. Yes, that was the original statute.

Q. And having read the company's position on the first issue about the treatment of the deferred charges, I understand that by this reference you also allude to the Commission's regulation or rule authorizing a utility to seek recovery?

A. Yes. I believe that statute instructed or, you know, the PSC ultimately set rules up to implement that statute.

MR. McGLOTHLIN: I am going to ask Tricia to distributive a document at this point?

CHAIRMAN GRAHAM: Does this need an exhibit number?

MR. McGLOTHLIN: Yes, please.

CHAIRMAN GRAHAM: 195. Do you have a title?

MR. McGLOTHLIN: We can call it PSC Rule 25-6.0423.

(Exhibit Number 195 marked for identification.)

BY MR. McGLOTHLIN:

Q. Mr. McMillan, we have provided you with a copy of Rule 25-6.0423. Do you have that in front of you?

A. Yes, I do.

Q. Do you see that I have highlighted with pen certain definitions under the definition section?

A. Yes.

Q. Would you read into the record the definition of site selection circled as Sub E?

A. Site selection. A site will be deemed to be selected upon the filing of a petition for a determination of need for a nuclear or integrated gasification combined cycle power plant pursuant to Section 403.519, F.S.

Q. And would you also read Paren 4, which has been circled, and is the section on site selection costs?

A. Section 4, site selection costs. After the Commission has issued a final order granting a determination of need for a power plant pursuant to Section 403.519, F.S., a utility may file a petition for a separate proceeding to recover prudently incurred site selection costs. Do you want me to read on or just the highlighted?

Q. No, that's all. Has Gulf Power filed a petition to determine need for a proposed nuclear plant?

A. No, it has not.

Q. And would it follow logically that Gulf Power has not received an affirmative determination of need for a nuclear plant?

A. No. We have deferred the development or filing for a determination of need at this point.

Q. Your answer is yes, is it not?

A. What was the question? I thought I answered it.

Q. Would you confirm that you have not received a determination of need, an affirmative determination of need for a nuclear plant?

A. That's correct, yes.

Q. If you will, please, turn to Page 17 of the same document and take a moment to become familiar with Lines 9 and 10 and also 13 through 16?

A. I'm sorry, where were you wanting me to look at?

Q. I am going to refer you for purposes of this question to Page 17 of your Direct Testimony, same document.

A. Sorry. You switched horses on me there. Okay.

Q. And you describe there the reasons why you believe, the company believes a hiring lag adjustment would be inappropriate, should the Commission determine that the company is unlikely to have all positions filled at the time, is that correct?

A. Yes.

Q. And your first reason is that such an adjustment assumes that if a position is not filled, the associated funds would not be spent, correct?

A. Yes.

Q. And you also say a hiring lag adjustment assumes the labor costs should be looked at it in isolation, correct?

A. Yes.

Q. As I understand it, you are suggesting that if the Commission were to determine that the company will not need the full amount that it has built into the test year for payroll expense, it should refrain from making an adjustment so that the company could then redeploy that unspent money elsewhere, is that correct?

A. I wouldn't characterize it in exactly that format. I believe what I have testified to and through discovery mentioned is that you shouldn't look at the labor component in isolation or other -- there are times when management for good reason determines to delay or not fill a job due to other higher priority items that need to be addressed immediately. So that is more or less where I'm going at here.

In addition to, as you pointed out in the first point, a lot of times we have to backfill through either contract labor or overtime to fill in for the positions that are vacant.

Q. Now, in your summary and also in your testimony you describe that you are sponsoring a projected test year that is representative of future conditions, am I correct?

A. Yes.

Q. And that includes rate base and operating expenses, correct?

A. Correct.

Q. And in performing and constructing the test year, did the company identify with as much precision as possible the full revenue requirements that it would need to operate the company and earn a fair rate of return?

A. Yes, based on what we know today, but there will be things that come up, regulations and other that we will have to address as time passes.

Q. When you say labor should not be looked at in isolation, are you suggesting that any overrecovery of dollars earmarked for labor should be available to use elsewhere in the company?

A. No. I'm saying that dollars that are identified as labor may be deployed in other activities, but not overfunding of it. We have identified the correct funding level and the amount of employees that our functional witnesses have identified and justified as needed to do their jobs. But management has to evaluate daily challenges and opportunities, and so, yes, we may not fill a position for some period of time in order to make sure we get our customers' business taken care of.

Q. And if the Commission were to determine, based upon the evidence, that the company has overstated payroll expense because the Commission disagrees with the assumption of full complement, are you suggesting that it should not make an adjustment?

A. Well, I think we're getting over into my rebuttal, but, yes, in my direct I said I do not believe any type of adjustment to our complement or for hiring lag is appropriate. But in my rebuttal testimony, I do address if the Commission were to determine that such an adjustment was necessary, how I believe it should be calculated.

Q. Well, I'm looking at your first direct testimony, and there on the same page you describe how sources can and will be deployed from one budget category to another, and that's the statement that prompted the question I asked you. And if you are suggesting that labor should not be looked at in isolation, would it follow that any other category of expenses should not be looked at it in isolation, as well?

A. I would think, yes.

Q. And if that is the case, are you suggesting that the Commission should look at each category of expenses as some type of contingency fund available to be redeployed elsewhere in the event the company does not need it for the purpose stated in the representative test year?

A. No, that's not what I said. I said you should be looking at each of those and determining whether or not they are reasonable and justified, not whether or not the company is going to spend that exact dollar amount. I can assure you we aren't. A budget is a plan, and the plan is developed in order to try to efficiently and effectively run the business. But in reality, that plan is changed on a monthly basis based upon real world challenges. So that is all I was trying to articulate.

Each of our functional managers, in their testimony they identified the required staffing to get the job they say they need to get done in order to meet our customers' needs. And to sit here and try to make an adjustment because we have got some vacancies today I don't think is appropriate.

Q. Okay. You mentioned the fact that circumstances or plans can change over time. Would you agree that not only cost, but revenues that are built into the representative test period can also change, they can be more or less?

A. Absolutely.

Q. And, in fact, after base rates were set in your last rate case, it has been established that during some periods the company had sufficient revenues to earn its maximum authorized return and make discretionary accruals because revenues exceeded expectations at the time rates were set, is that correct?

A. I wouldn't go that far. I mean, there were some discretionary accruals, but it's a combination, not just revenues. You're looking at a period way past the test period, and so there is a lot of moving parts, rate base, NOI, expenses, et cetera.

Q. On that we agree, sir. But I will take you back to the earlier statement you made, which is that the decision should be based on what is reasonable and justified, correct?

A. Yes.

Q. And would you agree that the Commission should base its decision on whether the projections of the company are reasonable and justified?

A. Absolutely, our test year level of expenses, correct.

Q. And if the Commission were to determine that a particular projection is unreasonable and unjustified, would you expect them to make a downward adjustment, accordingly?

A. I can't make their judgment for them, I'm sorry, but I would think that reasonable and justified and prudently incurred are all accepted criteria to be met.

Q. In that same document, please turn to Page 29, and tell me when you're there.

A. I'm there.

Q. I'm looking at an answer that begins on Line 21. The question reads, "If the Commission did not allow recovery of the full Crist scrubber project cost through the ECRC, would any action be required to address those costs in this rate proceeding?"

Would you read your answer there?

A. Yes. Do you want me to read the entire answer?

Q. Through the next sentence.

A. "In the event any portion of the Crist scrubber costs are not allowed for recovery through the ECRC, the adjustment I have made to exclude these costs from rate base would have to be reversed in order to permit the recovery through base rates."

Q. Now, if I understand that testimony correctly, the starting point with respect to these Crist scrubber costs was that they were in rate base and you had to remove them for purposes of the rate case filing, am I correct?

A. No, you're not correct. They were in our total system amounts that I established from Mr. Buck's financial forecast, and from those total system unadjusted amounts I removed the regulatory adjustment, including the amounts for the clauses or any other, like, nonutility property. Things like that are all backed out for determining the appropriate amount for consideration of base rates.

Q. Okay. I need to follow that up because I don't understand your answer yet. The prefiled testimony says the adjustment I have made to exclude these costs from rate base, that suggests to me that at one point they were in rate base and you have made an adjustment to exclude them. Am I right or wrong?

A. They are not in rate base for setting of base rates. They are -- all I said is I removed them from rate base. In other words, they are not in there. But essentially rate base is an accumulation of costs, your net investment in plant, working capital, essentially, and there is a lot of calculations involved in that. But the way that is done, which I discussed in my summary, is you start off with total system financial records right off our books, and then I make certain ratemaking adjustments to remove the costs that are not to be considered in the base rate setting process. And those were removed in those regulatory adjustments for the clauses.

Q. Okay. And then you say those adjustments that you made to exclude these costs from rate base -- and I think I understand what you meant now -- would have to be reversed in order to permit the recovery through base rates. What would be involved in reversing the first adjustments, what entries would be involved?

A. Well, you would have to recompute the adjustments, you know, the adjustments that I had made to remove them, related to the clause, would have to be adjusted.

Q. And would that result in the scrubber costs being placed in a 13-month average rate base for the base rate proceeding?

A. Yes. If I reduce that adjustment it would actually result in an increase in the base rate amount.

Q. Now, you have alluded to the two alternative proposals that you support in your Supplemental Direct

Testimony with respect to those scrubber costs, correct?

A. That is correct.

Q. Would you agree with me that neither of those alternatives is identical to what we just described, which is placing those scrubber costs into a 13-month rate base for ratemaking purposes?

A. They are not identical. They accomplish the same. For the 2012 -- both of the proposals I made result in the same amount of recovery in 2012. We're asking for the annualized costs to be placed in service into rate base for developing base rates, and then a credit to flow to the customers through the ECRC for the difference in 2012, so that in 2012 you get exactly the same answer.

Or, alternatively, they could do exactly what this says and then provide a subsequent year adjustment in the beginning of 2013 since the last project of those three does not go into service until December of '12.

Q. I believe you answered my question, but let me make sure. If the theme is to place the turbine upgrades in a 13-month rate base in the conventional manner as a consideration of removing from the clause, would you agree that the two alternatives you have suggested are essentially variations on that theme designed to accomplish a result different from the conventional ratemaking treatment?

A. I wouldn't know of conventional ratemaking. It is different than just making -- we are asking to recognize that there are significant benefits accruing to the customers related to these improvements that were done with the scrubber project, which originally was approved in the ECRC, and all we're asking is based upon a policy change by the Commission and through a stipulation we have agreed to address this in this docket.

So I'm trying to be a little broader probably here than you would like to hear, but essentially what we are asking is to be treated fairly and the company to be equitably treated moving those back. We are asking for the annualized impact in 2013, which is the same amount we would have recovered in the ECRC. We're just asking to handle it in this docket versus essentially having to come back to the Commission, because what it does -- it's a known fact that if you just pull the 13-month average of the amount for 2012, you're only going to recover half the carrying costs of that project, and all the benefits for those projects are flowing through the clauses. And so there is a mismatch there, and it doesn't really make a lot of sense.

Q. Would you agree with me that your two alternative proposals have as their objective accomplishing for Gulf Power with respect to revenues the same result through base rates that they would have seen had the investments remained in the environmental cost-recovery clause?

A. Yes, I would agree with that. Through 2013 they would be the same.

Q. Earlier you said that once base rates are set, then over time there are lots of moving parts, correct?

A. Yes.

Q. And that by moving parts you meant investment, revenues, and costs, all of those could be moving parts?

A. Yes.

Q. And would you agree that with respect to the evaluation of the adequacy and sufficiency of base rates, the company's achieved or earned rate of return is reviewed in the aggregate on an overall basis?

A. It's an average calculation based on all of those parts, your NOI divided by rate base, yes.

MR. McGLOTHLIN: I have no further questions.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: Thank you.

CROSS EXAMINATION

BY MR. MOYLE:

Q. Let me refer you back to some of your testimony, and Mr. McGlothlin asked you some questions about the nuclear site. I am assuming since you put testimony in here about this nuclear site that you have some familiarity with it and some details about it, is that fair?

A. I'm really not the witness to deal with the details. I'm the witness to deal with the ratemaking part of it. I think Mr. Burroughs and Ms. Alexander in rebuttal would be the witnesses.

Q. So your statement on Page 5, Line 19, that the Northwest Florida site is the only site in our service area suitable for nuclear generation, if I asked you questions about that, how you went about coming to that conclusion, you probably wouldn't be able to answer that?

A. Well, I'm aware of the studies and some of the site selection information. I attended some of those meetings. But, again, I'm not the expert or the person that could give you details.

Q. Well, let me ask you some questions and see how far we get.

A. All right.

Q. I think we have already established that this nuclear project is not needed for more than ten years, correct?

A. I believe that was the testimony of Mr. Burroughs, yes.

Q. And your company has condemnation power, does it not?

MR. MELSON: Objection, beyond the scope of his direct.

MR. MOYLE: I mean, he talks about this nuclear plant. I simply wanted to get him to confirm that they have the ability to condemn property, and that that is an option that they could have considered. Why have they got to buy it in 2012 for something that's coming in in 2022.

CHAIRMAN GRAHAM: I'll allow him to ask the question. Sir, are you aware that you have condemnation power?

THE WITNESS: Again, I'm not an expert in that area, but I do believe you are correct there.

BY MR. MOYLE:

Q. And do you know -- because you have a statement in here about the land purchases will be completed in 2012 up on Lines 15 and 16, are the land purchases not completed as we sit here today?

A. Not completely, no. The majority of them have been, but they are not completed.

Q. So if the Commission were to say, you know, we are not real comfortable allowing this coming into base rates this far out in the future, would I be safe in assuming that a purchase not yet completed may be able to be undone?

A. Well, let me clarify a little bit on my last thing. There were some budgeted additions in 2012 that I didn't -- that weren't included in the amount I requested. What I had included in the test year were the amounts that were budgeted to be spent by the end of 2011. Or, just rephrase your other question.

Q. Do you know, as we sit here today, for land that has not yet purchased, if the Commission were to make a ruling that this is not appropriate to include in base rates, whether you would be obligated to move forward with those purchases, or would there be the ability to not move forward, do you know?

A. Once we get the decision from this Commission, company management will determine what the best course of action is. I will say that the majority of those land purchases have been made.

Q. Okay. Do you know with respect to the lands in 2012 or the lands that have previously been purchased, was there a contingency or a condition precedent or a condition subsequent that the Commission have to approve these lands going into rate base in order for the deal to be consummated?

A. Again, I'm not an expert, but I don't believe there were any conditions. The lands that were purchased were purchased.

Q. Do you know, did the company consider trying to execute an option on the property before making a decision to buy it, do you know?

A. Again, you are probably getting into some things Ms. Alexander could tell you, but I do know there was an option on one of the large tracts of land that was extended a couple of times and ultimately was purchased.

CHAIRMAN GRAHAM: Mr. Moyle, let's move on. He said there is a witness that can these questions better.

MR. MOYLE: I will, Mr. Chairman.

BY MR. MOYLE:

Q. Page 13. You're seeking monies related to pensions, is that right?

A. Pension expense would be included in our operating cost, yes.

Q. And as we sit here today, the company continues to offer pensions to its employees?

A. Yes.

Q. And are those negotiated through labor contracts with unions or not, or is it a mixed bag?

MR. MELSON: Mr. Chairman, objection. Pension expense has been stipulated.

MR. MOYLE: This may teach me to be -- I know we want to do stipulations, but I'm kind of maybe getting a little disincentive on some of them. If we have stipulated to the issue -- if he could answer the question just for the record, making the record as to whether they are offering pensions through unions or not, I would appreciate it.

CHAIRMAN GRAHAM: Is that your last pension question?

MR. MOYLE: Yes, sir.

CHAIRMAN GRAHAM: Sir, can you answer the question for him?

THE WITNESS: The pension fund plan is related to all employees, so whether they are in the union -- but, I mean, it is a union negotiable item, but as far as I know they have the same pension as the rest of the employees.

BY MR. MOYLE:

Q. All right. I want to ask you a question about your supplemental testimony that I have that relates to the interim rates. Did you file testimony related to interim rates on July 8th, 2011?

A. Yes.

Q. Okay. Why did you file this testimony?

A. In order to petition the Commission to get interim rates.

Q. Was this testimony before the Commission and for consideration when they voted on the interim rates?

MR. MELSON: Objection, calls for a legal conclusion.

MR. MOYLE: If he knows.

CHAIRMAN GRAHAM: Restate the question.

MR. MOYLE: His supplemental testimony has information related to interim rates. It's my understanding we have kind of been there and done that. Y'all considered interim rates. I know we made an argument against them and it was accomplished. So I'm trying to understand why in this proceeding we have testimony related to these interim rates, and that's what I was trying to --

CHAIRMAN GRAHAM: Was your question did they come out before or after that hearing, interim rates?

MR. MOYLE: Yes, sir.

CHAIRMAN GRAHAM: Sir, do you know?

THE WITNESS: I mean, the interim decision was made at an Agenda Conference earlier, but it is not permanent until we get final rates set.

BY MR. MOYLE:

Q. Yes, sir. But this testimony wasn't in front of Commission when it made its decision on interim rates, was it?

A. It was available to the Commission; it was filed.

Q. But you weren't here as a witness to take the stand. I mean, it wasn't offered in like we are doing today, was it?

A. I will defer to the legal. I wasn't here. I was in the audience.

MR. STONE: Mr. Chairman, as noted in the Prehearing Order, the Supplemental Direct Mr. Moyle is referring to was filed on July 8th, 2011, with our petition. It accompanied our petition for interim rates. It was testimony that was submitted by affidavit; it was under oath; it was for the Commission's consideration at any time.

The nature of the statute for the interim statute does not require that there be a hearing in order for the granting of interim rates. I'm not sure where Mr. Moyle is going with this, but the point of our supplemental testimony was to have sworn testimony under oath documenting how we met the standard under the statute.

MR. MOYLE: That's helpful. I have just one or two more questions on this and then I will move on, if I could, Mr. Chairman.

CHAIRMAN GRAHAM: Okay.

BY MR. MOYLE:

Q. On Line 23 you are asking or testifying about a lower-cost option than posting a bond. What undertaking did you pursue in order to provide guarantee to the ratepayers that to the extent the Commission awards less than 40 million that they will be refunded monies?

A. Could you tell me what page you're on?

Q. Sure. Page 2.

A. All right.

Q. Line 23.

A. All right. What was your question?

Q. Did you post a corporate undertaking to secure the refund obligation as we sit here today?

A. No.

Q. I'm sorry?

A. No. I mean, the company -- basically, the lowest cost is always -- the company can actually just do it under a corporate undertaking, and that's what the Commission approved versus posting a bond; you have to pay someone and there is a cost involved.

Q. Okay. And with respect to a corporate undertaking, have you done that?

A. We provide evidence to staff that we were financially able to make the refund.

Q. Okay. Now, let me go to another area of your testimony related to the capital structure. You spent some time on Page 21 talking about the revenue deficiency.

A. You're back on my Direct, right?

Q. Yes, sir, I'm sorry.

A. Okay.

Q. All right. And you live in Pensacola, is that right?

A. Yes.

MR. MOYLE: Mr. Chairman, I have just a couple of sort of preliminary questions, and then I want to get into these numbers, if I could.

BY MR. MOYLE:

Q. But you are aware that the State of Florida has had a significant budget deficit the last couple of years, are you not?

A. What I've read on the intranet (sic) and Internet.

Q. And you are also aware, are you not, that that budget crisis or budget deficiency, at least in the

State of Florida, has been dealt with through cuts in expenditures and programs, correct?

A. Again, only what I have read in the newspaper and in the news.

Q. And you have read that that is how the State of Florida has dealt with deficiencies?

A. Well, I think that is how most governmental entities that can't print money -- I think the federal government is the only one that gets away with running large deficits for any length of time.

Q. And taxes and rates share some similarities, do they not? Because, I mean, another option is to raise taxes, and the State of Florida has not done that, but you would agree that taxes and rates share some similarities?

A. As a funding vehicle, maybe, but it's totally different because we have got an obligation to serve. And the State has certain obligations, but they also have discretionary money, and, again, that's part of government.

Q. Let me just spend a minute about taxes and rates. They are both imposed by government, correct?

A. What's that?

Q. Taxes and rates?

A. In our case, yes, these are regulated rates.

Q. And there is no competition -- with respect to your business, there is no competition with respect to government, correct?

MR. STONE: Mr. Chairman, I must object. The rates charged by an electric utility do not constitute taxes. We are not a taxing authority. We are a private industry that is subject to the regulation of this Commission. We are only allowed to charge prices that are approved by this Commission. It does not equate to taxation, and so, therefore, the comparison between rates that are approved for electric service subject to the regulation of this Commission to taxes is far beyond the scope of this witness' testimony, and the comparison is not appropriate, and we object to the line of questions.

CHAIRMAN GRAHAM: Mr. Moyle, let's see if we can skip forward to your specific question. We don't need to lay the groundwork. If you feel like you have got to lay the groundwork after you get into the questions, we'll come back.

MR. MOYLE: I think for the purposes of my questions, you know, I would make the contention that taxes and rates share some similarities. I think he has answered a couple, but I will continue on.

BY MR. MOYLE:

Q. Gulf Power Company has not ordered -- in order to deal with its business situation, they have not ordered any across-the-board reductions like a 5 or 10 percent reduction in expenses, correct?

A. Not just across-the-board irrespective of regulatory requirements, no. But we have continually --

Q. Are you aware that that has taken place at the State of Florida, at the state government level there has been directives to state agencies, give us 10 percent cuts?

A. Well, there is more efficient and effective ways of making reductions than across-the-board, but I understand sometimes that's your last resort.

Q. And there has been no freezing of salary increases at Gulf Power, correct?

A. I think someone mentioned earlier we actually didn't skip the -- we didn't give any pay raises in '09, but other than that, no.

Q. So with the exception of '09, you have had annual pay increases, correct?

A. Yes.

Q. And the number of FTEs have increased, correct?

A. We have justified the additional FTEs that we say we need. I mean, and part of that was driven by the Commission changing our conservation programs substantially to meet FEECA requirements. So, you know, again, that's all laid out in my testimony and the functional witnesses.

Q. I understand. So that would be a yes on the increase of the FTEs, correct?

A. Yes.

Q. And the O&M numbers have gone up, correct?

A. Yes.

Q. And currently there is a less than one percent per annum growth rate with respect to your company in terms of new customers, correct?

A. I don't have those numbers, but it has been pretty flat the last few years.

Q. And the order of magnitude with respect to the rate increase is approximately 20 percent, is that right?

A. No, that doesn't sound right.

Q. What is the percent of the rate increase that most customer classes can expect to receive?

A. I don't have that in front of me.

Q. Let me move on and refer you to your Exhibit 4, Schedule 4, Page 1 of 3. It's your net operating income exhibit.

A. Okay.

Q. And you're seeking in your operating expenses, the number you are seeking is $282 million, is that right?

A. 282.7, yes.

Q. Okay.

A. If there was -- that's just the O&M. I mean, when you say operating expenses, you have to pick up depreciation and several other items.

Q. Well, if I asked you back on Page 21 to assume a 10 percent cut of 1.6 billion --

A. I'm sorry, you want we to go back to Page 12 and do what?

Q. On Page 21 you have a rate base of 1.6 billion, right?

A. Yes.

Q. Okay. If I asked you to assume a cut of 10 percent of that, kind of like state government if you had a 10 percent cut, that would be 160 million give or take, is that right?

A. Yes. That is rate base obviously.

Q. I understand. There's depreciation and some other things built in there that you couldn't cut, right?

A. Well, depreciation is usually only about

3-point-something percent of that.

Q. And I guess the point, to get to it kind of in a conclusory fashion, but if this Commission were to say, look, we want to increase your return on equity, but we're not comfortable doing it by just on the revenue side giving you $100 million in revenue. We want you to take some cuts, kind of like state government, the number that you would look at would be the 282 number, isn't that right, because those are your expenses that you could look to trim?

A. Those are the requested test year O&M amounts that we don't feel should be trimmed. We feel like that is reasonable and justified.

Q. That would represent about 2-1/2 basis points, 2-1/2 equity points in terms of your return on equity if there was a cut of 10 percent, do you know that?

A. Ten percent of what, of 280?

Q. Of the 280.

CHAIRMAN GRAHAM: I think there's a calculator to your right.

BY MR. MOYLE:

Q. I understood each 100 basis points, or one percentage point was worth about 11 million bucks?

A. Yes. If you took 10 percent of that, it would be like 28 million, so you'd be looking at two-and-a-half -- 250 basis points.

Q. All right. And with respect to the earnings, the Southern Company is the one investing equity capital, correct, into Gulf Power?

A. They do, yes, they are.

Q. So another way to increase return on equity is to reduce expenses, correct?

A. Increase revenues, decrease expenses, yes.

Q. The final line of questions I had related to Southern Company Services, and you have some testimony about that. It starts on Page 27 of your Direct. I had asked a couple of witnesses about how you price services that are provided by Southern Company Services for, say example, engineering. Do you know how that is done?

A. Well, it's not an easy one answer, but obviously there is multiple different allocators that are used, but they provide professional and technical services to all of the operating companies at cost, and typically if they are working directly for Gulf, those folks, like the folks that worked on our cost-of-service study, they would charge directly to Gulf Power for their services. To the extent you have A&G and general corporate type folks doing things that are to the benefit of all the companies, they are allocated between the companies based upon various allocators depending on the area and what the most cost causative type allocator we could identify for that type of service.

Q. Do these functions -- do they provide -- I assume they provide revenue to the Southern Company.

A. No, not the service company. The service company is strictly there to provide services to the operating company and the other affiliates, and they bill out 100 percent of their costs every month. And they file reports with the FERC. They used to file with the SEC, but they have a complete accounting of all their expenses and how they are billed out.

Q. Just a couple of other questions. You talked about support in areas -- this is on Page 27 -- such as accounting, supply chain management, finance, treasury, human resources. When I read your testimony I was assuming that that was then services that were provided by SCS exclusively, but that's not the case, correct?

A. Where exactly are you referring to that? I'm sorry.

Q. This is on Page 27 under the section entitled Southern Company Services, and you are asked, "Please provide an overview of Southern Company Services and its relationship to Gulf."

A. Yes.

Q. And you go on and talk about the various services that are provided.

A. Yes. Those are examples of the types of services. But, yes, they are not all-exclusive. Obviously we have Deloitte & Touche who is an external auditor who also provides services related to accounting to meet regulations. And there is probably other -- what we typically will do is we use the service company to the extent they are the most cost-effective and appropriate source of those services.

Q. Right. But let's take, for example, human resources. Does Gulf have its own human resources department?

A. We have some folks at Gulf that help with our hiring and personnel type decisions, but then compensation expertise and things that can be shared between the op-co's to avoid duplication is done by a group in Atlanta, and it provides a lot of benefits to a small company like Gulf. We don't have to staff for a lot of those type services or go outside and hire outside consultants to do that.

Q. Does Gulf have its own information technology functions?

A. Well, information technology is one of the groups that was functionalized back before the last rate case. I testified to that in the 2001 case. So we have some at Gulf, but they are all SCS employees. Again, trying to share resources and support for the various systems that are common throughout the system.

Q. Is there a review, Commission review of duplication of services in any of the service areas that you have, if you know?

A. I'm not aware of any right off the top of my head, I'm sorry.

Q. I'm sorry, I was saying other than in a rate case proceeding, do you know has there been dockets opened to say, well, wait a minute, maybe there seems to be duplication of services if there's a private company -- or an affiliated corporate entity providing the same or similar services that the regulated company is having, are you aware of any proceeding that has looked specifically at that?

A. I'm not aware of any such things occurring, no.

MR. MOYLE: Okay. That's all I have. Thank you.

CHAIRMAN GRAHAM: Major Thompson.

MAJOR THOMPSON: No questions.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman. I just have a few questions.

CROSS EXAMINATION

BY MR. WRIGHT:

Q. Good afternoon, Mr. McMillan.

A. Good afternoon.

Q. I just have a couple of questions. In response to some questioning, I think, from Mr. McGlothlin, or maybe it was Mr. Moyle, you said that your role with respect to the North Escambia nuclear site is that you are responsible for the ratemaking part, did I get that right?

A. Yes, more or less. The recovery of that and the basis for putting that in what should be included in our test year request.

Q. And I just want to ask you a couple of questions along this line. As I understand it, when this site translates into ratemaking, it is going to cost about 26 cents a thousand kWh, does that sound right to you?

A. That sounds pretty close, yes.

Q. And that is for a site that won't be used before the mid-2020s, if ever, correct?

A. If our current projections are accurate, which they do change regularly, but, yes, that is what we are sort of expecting today because of circumstances that we know of today.

Q. Well, my question for you is how do you square collecting that kind of money from customers for the next 10 to 15 years, as a matter of generational equity or intergenerational equity, with the company's position on the storm accrual?

A. I think it's a good prudent decision for the company to prepare and plan for the future. Our business is not -- we can't make a decision tomorrow and just assume we can go out and get a site. The site -- again, I'm not the witness that can give you a lot of the details, but I was involved in some of the decisions, and this was determined to be the best alternative site, or best and possibly only site in our service territory that a nuclear unit could be put on.

And based on rules at the time when we were doing a lot of those studies -- the governor in place at that time and other things -- we were moving ahead to build a nuclear. Things have changed obviously. We are prudent management, and we decided to defer that decision. But, still, if you ever want to build a nuclear unit, if we wait 20 years down the road there could be industrial plants up in that area. You can't predict the future that far out. So we still feel it's a prudent thing to get this land. It seems like a lot of money. $26 million is a lot of money to you or I as an individual, but as he mentioned, Mr. Moyle mentioned earlier, we are looking at 1.6 billion just in the base rate, add another billion in the clauses. I mean, it's not as significant in the overall scheme. If you wait 20 years, that site could cost us hundreds of millions, who knows.

Q. It's about $4 million a year in revenue requirements, isn't it?

A. Not that high, no, I wouldn't think.

Q. About 3?

A. A little less than 3, yes.

Q. But, again, you are asking customers to pay for it for the next 15 years, even though it may never be used, right?

A. The carrying costs on it, yes.

Q. That concludes that line of questioning. I have a few questions for you about the company's request for the $60.9 million of construction work in progress in rate base. It's Issue 22, and you are offered as the company's witness on that. It is in your --

MR. MELSON: Objection. This goes to his Rebuttal Testimony.

MR. WRIGHT: Well, it is part of his Direct exhibit, Mr. Chairman.

MR. MELSON: I will withdraw the objection.

MR. WRIGHT: Okay.

THE WITNESS: Yes, I think Mr. Deason actually has rebuttal on that, but I'll be glad to answer your question.

MR. WRIGHT: Well, I think you may do some rebuttal on it, too, but I wanted to ask you just what is going on here.

BY MR. WRIGHT:

Q. I'm looking at your Exhibit RJM-1, Schedule 2 to your regular Direct Testimony.

A. Yes.

Q. Okay. And that shows about halfway down construction work in progress requested and the jurisdictional adjusted rate base of $60,912,000, correct?

A. Yes.

Q. Now, do I understand correctly that that is a request to include in rate base that amount for what is denominated noninterest-bearing CWIP?

A. Yes.

Q. Can you name some projects or give us examples of some projects that would be in there?

A. I don't have my MFRs with me, but there is a listing, a detailed listing of what all is in that number in the MFRs, CWIP by project.

Q. Is it the case that they are in there, that you want them in there because they don't qualify for AFUDC?

A. Well, obviously, as anyone that invests money, we have two alternatives, or the Commission has in their rulemaking and, you know, we have a rule here that only allows certain projects to calculate to accrue AFUDC. They have to be in excess of a year in construction, and dollar-wise have to be in excess of half a percent of your plant-in-service.

We follow that rule explicitly. We have backed that number out in our regulatory adjustments, but obviously the investors, the company needs to earn a return on the projects that are under construction. If you don't get an AFUDC return, it has always been included in rate base in Florida ratemaking.

Now, you know, this is unheard of to expect people to go out and spend money with no return, no expected return. There's no basis for that. I don't understand where you are even coming from. How are we going to make that up? That would automatically -- $60 million would roughly short our request by 6 million. Well, who's going to pay us that 6 million if the ratepayers don't pay for that construction cost? The other alternative, if you don't like putting it in rate base, is to get the Commission to change its rulemaking and let us calculate AFUDC on all CWIP.

I think this is the better policy that the Commission has. It's better for cash flow for our credit metrics. And this was changed many years ago. We have been following this same AFUDC rulemaking here in Florida -- I forget exactly when they went to the one year construction period, but it has been quite sometime. And so this is the first time this issue has been raised. I'm flabbergasted, as a financial person.

Q. Are any of these assets going to be used and useful during the 2012 test year?

A. Yes, a lot of them will be in service. This is the 13-month average of the CWIP balance. So all of these are projects under a year in construction, so everything that's in CWIP, a portion of that -- some of it is in service. You know, 2/13ths of it could be plant in service and 10/13ths, you know, you have to go back to that. There is an MFR that lists the projects and when they went into service, so I'm not sure where I can go from there.

Q. Okay. And to the extent they are in service and used and useful during the test year, they are in rate base during the test year, correct?

A. That portion is in our plant-in-service portion of rate base. The CWIP portion is here as another line item. It's no different than working capital. If you're saying I shouldn't get a return on my CWIP, which you get -- you can't snap your fingers and stuff is built. It takes dollars, money, and resources. Why do you think we have a working capital allowance? Again, there's dollars invested in our business day in and day out to keep the lights on and to do our jobs. This noninterest bearing CWIP is no different than other working capital requirements. We can't build things overnight. It take two, three, four months for some of these projects. So I don't see how you could draw any distinction why that wouldn't be authorized a return.

MR. WRIGHT: Thanks.

That's all I have, Mr. Chairman.

CHAIRMAN GRAHAM: Staff.

MS. KLANCKE: We are going to hand out a few documents, but this should be brief.

CROSS EXAMINATION

BY MS. KLANCKE:

Q. Good evening, Mr. McMillan.

A. Good evening.

Q. Do you remember when I took your deposition on Wednesday, November 16th, 2011?

A. Yes.

Q. And I have handed you a copy of your deposition transcript, have I not?

A. Yes.

Q. Did you have an opportunity to review this deposition transcript and sign it?

A. Yes, I did.

Q. Having reviewed the deposition transcript before signing, your answers to these questions remain the same today, is that correct?

A. Yes, with the notation of the errata that I provided.

MS. KLANCKE: Certainly. At this time I would like to move this witness' deposition transcript into the record.

CHAIRMAN GRAHAM: Which is Exhibit 150.

MR. McGLOTHLIN: OPC objects for the reasons previously stated.

MR. MOYLE: So does FIPUG.

CHAIRMAN GRAHAM: And I would assume that Mr. Wright and Major Thompson both object because they objected to the --

MR. MOYLE: That's probably a fair assumption.

CHAIRMAN GRAHAM: Okay. We will move 150 into the record.

(Exhibit Number 150 admitted into the record.)

BY MS. KLANCKE:

Q. I'd like to turn your attention now to the separate handouts I have provided to you. It is entitled "Late-filed Exhibit Numbers 2, 3, 6, and 7." Do you see that document?

A. Yes.

Q. Are you familiar with this document?

A. These exhibits were prepared under my direction, yes.

MS. KLANCKE: Excellent.

At this time I would like to have an exhibit number provided with respect to this document.

CHAIRMAN GRAHAM: We will give it Exhibit Number 196.

(Exhibit Number 196 marked for identification.)

BY MS. KLANCKE:

Q. Would you briefly describe, for the record, what these documents entail starting with Exhibit Number 2?

A. All right. Exhibit 2 were the accounting entries and MFR changes needed to reflect the moving of plant held for future use to plant in service related to the Sandestin substation site.

Q. And Exhibit Number 3?

A. Exhibit 3 is some detailed information related to Work Order 4Q51RC.

Q. Exhibit Number 6?

A. Number 6 included the SEC approval of the financial factor.

Q. And Exhibit Number 7?

A. Number 7 was the updated 2010 allocation factors.

Q. Thank you. I would like to turn your attention now to the final handout, which is labeled Gulf's Response to FEA's First Set of Interrogatories Item 15. Were you here earlier in the proceedings when FIPUG objected with respect to the entry of this deposition -- of this exhibit, which is contained in Hearing Exhibit Number 120?

A. I was informed that they did. I wasn't here exactly.

MS. KLANCKE: Chairman, for the purposes of the clarity of the record, pursuant to some conversations that staff has had with FIPUG, we have clarified and resolved their objection which -- can I confirm that they have withdrawn?

MR. MOYLE: That is my understanding. We have withdrawn the objection.

MS. KLANCKE: Excellent. I would like to have this given a number.

CHAIRMAN GRAHAM: 197.

(Exhibit Number 197 marked for identification.)

MS. KLANCKE: That is all the questions I have for this witness.

CHAIRMAN GRAHAM: Ms. Klancke, before I move on, I have a question for you.

MS. KLANCKE: Sure.

CHAIRMAN GRAHAM: Under the depositions, specifically 151, 153, 154, 155, and 156, do you plan on entering those all into the record?

MS. KLANCKE: Let me take a moment to confer with the other attorneys.

CHAIRMAN GRAHAM: Okay. We'll come back to you.

MR. MOYLE: Mr. Chairman, in my cross I failed to ask one question that I would like to pose. I promise, one question.

CHAIRMAN GRAHAM: Just so long as it doesn't have to do with the property for the nuclear plant.

MR. MOYLE: It doesn't.

CHAIRMAN GRAHAM: Okay. Thank you.

FURTHER CROSS EXAMINATION

BY MR. MOYLE:

Q. Page 15 of your prefiled, at Line 23 you were asked about Commission adjustments, I think, related to your last rate case, and you indicated that the Commission made adjustments related to your expense forecast for the 2002 and 2003 test year. What were the areas in which adjustments -- I assume they were downward -- were made in your last rate case?

A. Again, I don't have that. There is an MFR, I think, that lists it, but I can't remember. They were just forecast type adjustments.

MR. MOYLE: If I follow up?

CHAIRMAN GRAHAM: Sure.

BY MR. MOYLE:

Q. I was curious as to whether they were forecasts for your FTEs, your number of employees, for your O&M expense, for, you know, capital expenditures, you know, just flesh that out.

A. This is NOI. I think it was dealing predominately with O&M type adjustments, but there may have been a depreciation adjustment. I don't really have the rate order in front of me. There's an appendix in the back of the order that lists specifically what the adjustments are.

Q. I understand, but I thought it was live because of your testimony here where you are referencing the adjustments.

A. Yes, I understood there were none, other than forecast adjustments, but I don't have them right here.

Q. And when you say forecast adjustments, are those the ones you just referenced in terms of O&M and things like that?

A. Yes, it was.

MR. MOYLE: Thank you.

THE WITNESS: That's what I'm remembering.

Like I said, if you look -- there was a follow-up question there, I will say, on Page 16 where I did talk about the hiring lag adjustment. There was a hiring lag adjustment, so I don't want to leave you -- but that was one of the adjustments that I previously said I don't think was appropriate, but I did discuss it there.

MR. MOYLE: Thank you.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. I do have a question about the North Escambia property.

CHAIRMAN GRAHAM: Just as long as you remember there's somebody better to answer these questions.

COMMISSIONER EDGAR: Well, let me give it a try anyway, if you'll give me just a little latitude.

CHAIRMAN GRAHAM: Please, continue.

COMMISSIONER EDGAR: Thank you.

Mr. McMillan, Mr. McGlothlin asked you a couple of questions about Page 5 of your Prefiled Direct Testimony, and I want to come back to that section of your testimony.

THE WITNESS: Okay.

COMMISSIONER EDGAR: Witness Burroughs testified that the North Escambia site is being purchased to preserve a nuclear generation option, but that it is also suitable for other types of generation. And I think you have a similar statement somewhere in your testimony that I can't find right now. You also in this paragraph reference the rate base treatment that is being requested through statutory Section 366.93, which is specifically the nuclear and IGCC statute that prescribes some accounting treatment.

So my question is would the amount that is being requested for rate base for this site be different if the planned generation was neither nuclear or IGCC?

THE WITNESS: Well, obviously some of the site selection criteria and some of the testing that is going on would be -- it is my understanding and, again, I don't have all the documents I think we provided in discovery, but there are some of that that would only be needed -- those type of tests would only be needed if you were trying to certify it as a nuclear site. There's a little more stringent requirements geologically, et cetera. So some portion of the 27 million I could identify, I think -- I forget, off the top of my head, it's three or $4 million of that would be nuclear-specific type testing.

COMMISSIONER EDGAR: So if you took the total X minus approximately 4 million.

THE WITNESS: Right.

COMMISSIONER EDGAR: If this site were planned for a different type of generation, would that X minus 4 million be requested in rate base?

THE WITNESS: We would request recovery of it either -- depending upon, again, we would have to look at the individual studies and work with the folks that do the site certification details and the property accounting folks. I do believe some of that we would have to ask for recovery. If we determined we were never going to build a nuclear unit and those costs were sunk and would never be actually used for a nuclear site, some of that may not be appropriate to be recorded with other generation on that site, but we would ask the Commission for recovery of that and go ahead and write it off if it is no longer potentially viable for a generation facility.

COMMISSIONER EDGAR: Let me come at it from just a slightly different direction, then. If this site were planned for a non-nuclear or non-IGCC type of generation, would the costs be allowable in rate base under the statutes and rules as they exist today? Now. Not later, now.

THE WITNESS: Under your general ratemaking authority, yes. There's nothing -- as far as I know, there is no -- I know they keep throwing around used and useful. We are testifying that it is used and useful for preserving this option. Do we have a specific, date specific that we are going to build? No, but we have to get easements and things sometimes far in advance, too. It's just part of the business. It's a judgment call, but I do believe, and, again, it's more of a legal question than anything, but I feel y'all have authority to include it in rate base.

COMMISSIONER EDGAR: Okay. I'm going to ask a question on a different topic. In your supplemental -- the second that we have -- testimony, you discuss a primary and an alternate approach for the Plant Crist turbine upgrades.

THE WITNESS: Yes.

COMMISSIONER EDGAR: In your opinion, if you know, which of those two accounting approaches is most consistent with decisions that this Commission has made in the past for other companies?

THE WITNESS: Probably my alternate is more consistent with previous decisions. We, as I testified to, felt like we would put this other alternative on the table that gets you to the same place, and we felt it would be less confusing to our customers to have one base rate increase. They are used to having their clause factors changed annually, and we were going to have to adjust the clauses potentially, depending on the magnitude of what the cost of capital does, but we just felt like if we do that all at one time as one rate change for the ECRC and the base rates, and then the next year's ECRC would just be handled through its normal hearing process through that docket.

COMMISSIONER EDGAR: Thank you.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. I have a few questions.

On Schedule 19 in your exhibit, there is an item listed under general plant capital additions. In fact, it is the largest cost for 2012, Pine Forest Building/new office space. Could you describe what that plant addition is, capital additions?

THE WITNESS: Yes. As you know, we are adding a significant number of new employees. And at the time we were putting the capital budget together, we identified that we didn't have enough office space to house some of these employees without making some type of facility changes. And so at the time the budget was put together, this was an estimate of what we could get done. We knew if we moved forward with hiring the folks for the conservation programs we had to have office space for them fairly quick.

So that was sort of -- at the time we put this together it wasn't specific plans, but ultimately the dollars in 2011 ultimately ended up covering the costs. We actually finished off part of our third floor that had been used for storage to house those customer service people, and they are still finalizing plans for a building, a training facility and some office type facilities over at the Pine Forest complex, which is on the north side of town.

COMMISSIONER BALBIS: So if I understand you correctly, if the additional 159 employees were not required, you would not have a need for this additional space?

THE WITNESS: Well, not all of this. Some of if is new office space, some of it is for a new training facility and other operation center type of thing.

COMMISSIONER BALBIS: Okay. And to follow up on Commissioner Edgar's question on the Plant Crist scrubber projects, to kind of change gears a little bit, I want to make sure I understand this correctly. And I understand the alternative accounting process that I agree, I think it would be consistent with what this Commission has done in the past, which is moving it into base rates and taking it out of the ECRC. My question for you is have any costs associated with these scrubber projects been recovered through ECRC prior to the most recent clause proceeding?

THE WITNESS: You're talking about the turbine upgrade components of the scrubber project?

COMMISSIONER BALBIS: Yes.

THE WITNESS: Yes. As we testified, one of those projects went into service in January of 2010, and so we have collected in 2010's factor the cost of money and the depreciation related to that first turbine upgrade project that was completed and put in service in 2010. So a little less than $2 million were collected in 2010.

COMMISSIONER BALBIS: Okay. And then in the prehearing order for Issue 9, there is a statement on what Gulf's position is concerning this issue, which is

Plant Crist 6 and 7 turbine upgrades. And it states this should be accompanied by a one-time credit made to the ECRC clause in 2012. Will that credit include all of the costs that were recovered through the ECRC clause or are we missing costs that were recovered?

THE WITNESS: No, it's my understanding that the stipulation, all parties agreed that there would be no retroactive. The change to base rates was going to be prospective starting now. I mean, in '11. We agreed to pull it out of the 2011 factors, and now what we are asking for is recovery of the estimated amounts for the 2012 test year annualized.

So that ECRC credit has to do with if you annualize for the two projects that go into service in 2012, that $8 million annual revenue requirement is in excess of what the twelve-month average, or 13-month average amount would be if you just looked at the 13-month average investment during the 2012 test period. And it's roughly half. And so that's what that credit is related to. We said, okay, increase base rates by 8, throw a 4 million credit -- I'm talking round numbers because I don't have it in front of me right now -- through the ECRC. So in 2012 you end up with the same -- the same net amount as if you would have just used the 2012 twelve-month average amounts, and in 2013 forward the rates would reflect the full annual cost.

COMMISSIONER BALBIS: Okay. Then to summarize, then, for the ratepayers, whether it was recovered through ECRC or it is going to be recovered in base rates, it's going to be the same dollar amounts?

THE WITNESS: Right.

COMMISSIONER BALBIS: There is no double recovery?

THE WITNESS: That's correct.

COMMISSIONER BALBIS: Okay, thank you.

And last question. Concerning the costs that are listed in your testimony, what are the terms of your typical collective bargaining unit contract, the length? Is it a one-year contract, two, three?

THE WITNESS: Again, I'm not the one that would -- our compensation person could probably deal with that. Typically, they are either three to five years, but I don't remember what the current contract, when it expires and when it started.

COMMISSIONER BALBIS: Okay. So when this Commission moves forward with a decision on the revenue requirements for Gulf Power, nothing would preclude you from continuing to make adjustments to collective bargaining unit contracts to make it as cost-effective for Gulf's customers?

THE WITNESS: Well, I mean, at the time of the next union -- expiration of that contract and you are negotiating new terms and conditions. But, again, I don't remember when the current contract -- our contracts are not usually one year, they are usually three. I think the last one was for five years. But, again, I'm just talking right now. I don't remember exactly when that contract expires, if it would coincide with the decision in this rate case. I doubt it.

COMMISSIONER BALBIS: Okay, thank you.

CHAIRMAN GRAHAM: Redirect.

MR. MELSON: Just a few.

REDIRECT EXAMINATION

BY MR. MELSON:

Q. Mr. McMillan, to make sure we have got some of the dates absolutely correct, is it correct that the Crist turbine upgrades were pulled out of the ECRC factor for 2012, but they are in the factor that has been collected during 2011, pulled out prospectively for 2012?

A. Yes. That is the factor that was filed in '11 for '12, you're right.

Q. And have customers received fuel savings benefits through the fuel clause over the past two years from the first turbine upgrade project that went into service?

A. Yes.

Q. And I think you corrected it here at the end, but in some early questions from Mr. McGlothlin he was talking about a scrubber project. When you were talking about a scrubber project, were you referring to the Crist 6 and 7 turbine upgrades which were associated with the scrubber?

A. Yes.

Q. But not the scrubber itself?

A. No.

Q. Could you turn to Exhibit 195, which is Rule 25-6.0423 that Mr. McGlothlin had you read from?

A. Yes.

Q. I guess he didn't read everything I would have read. Would you read Subsection 1(f), which is right below the first highlighted portion?

A. Yes. Site selection costs are costs that are expended prior to the selection of a site.

Q. And then would you read (e) again?

A. (e) is site selection. A site will be deemed to be selected upon the filing of a petition for a determination of need for a nuclear or integrated gasification combined cycle plant pursuant to Section 403.519, F.S.

Q. So reading those two sections together, site selection costs are costs that are expended prior to filing a determination of need, is that right?

A. Yes.

Q. Now turn to Subsection 3, deferred accounting treatment, and read that one for me, please?

A. Deferred accounting treatment, site selection and preconstruction costs shall be afforded deferred accounting treatment and shall, except for projected costs recovered on a projected basis in a one annual cycle, accrue a carrying charge equal to the utility's allowance for funds used during construction (AFUDC) rate until recovered in rates.

Q. Is that the section that Gulf relied on in accruing carrying costs for the pre-need site selection costs?

A. Yes.

Q. Mr. McGlothlin also asked you to read from Subsection 4. Are you relying on Subsection 4 for your request in this case, or are you relying on the Commission's general ratemaking authority?

A. The Commission's general ratemaking authority.

Q. Commissioner Edgar asked you several questions about plant held for future use. Let me ask one follow-up. Disregarding the North Escambia site, assume you have got a site in South Escambia that is good only for a coal unit, not for a nuclear unit. If you were acquiring a site for a coal unit in South Escambia, would that -- and you were in the process of that and you came in for a rate case, would you seek to include costs related to that coal site in plant held for future use?

A. Yes.

Q. And is that consistent with the way the Commission has treated site acquisitions for non-nuclear sites in the past?

A. Yes.

MR. MELSON: That's all I've got. Thank you, Mr. Chairman. And I would move Exhibits 21, 22, and 23.

CHAIRMAN GRAHAM: Page 8, 21 and 22; Page 9, 23.

(Exhibit Numbers 21, 22, and 23 admitted into the record.)

MR. McGLOTHLIN: I move 195.

CHAIRMAN GRAHAM: 195 moved into the record.

(Exhibit Number 195 admitted into the record.)

MS. KLANCKE: Staff moves 196 and 197.

CHAIRMAN GRAHAM: 196 and 197 into the record.

(Exhibit Numbers 196 and 197 admitted into the record.)

MR. McGLOTHLIN: I would just like to observe that without waiving my objection to the deposition, I would stand on the basis I have no problem with these particular documents.

CHAIRMAN GRAHAM: Do you have a problem with the documents 196 and 197 or the deposition documents?

MR. McGLOTHLIN: 196 and 197, I have no problem with those. As I understand it, they were late-filed exhibits to the deposition. Notwithstanding their relationship to the deposition, on a stand-alone basis, looking at the documents themselves, I don't have an objection.

CHAIRMAN GRAHAM: Okay.

MR. MELSON: And, Mr. Chairman, just for clarification, I'm showing Exhibit 150 as having been entered, is that correct?

CHAIRMAN GRAHAM: That is correct.

MR. MELSON: Thank you.

CHAIRMAN GRAHAM: Ms. Klancke, the depositions -- 151, 153, 154, 155, and 156 -- which of those do you plan on entering into the record?

MS. KLANCKE: We plan on entering all of them.

CHAIRMAN GRAHAM: And I assume that Gulf plans that on not objecting to those entering?

MR. STONE: That is correct.

CHAIRMAN GRAHAM: And I assume all the intervenors plan on objecting?

MR. MOYLE: Yes.

MR. McGLOTHLIN: Yes. And in addition, if that includes the deposition of Ms. Ramas, I recall that during that deposition I objected to the form of one question which goes to the admissibility of that question and answer regardless of your ruling on the overall deposition.

CHAIRMAN GRAHAM: One more time.

MR. McGLOTHLIN: Yes. You have got basically two things to rule on. You have ruled, and I expect you will continue to rule that the deposition transcripts are in. But even with that, if a party posed no objection to a particular question at the time of the deposition as to the form of the question, the ruling on that is deferred to the point where it's offered as an exhibit.

CHAIRMAN GRAHAM: That's correct.

MR. McGLOTHLIN: So I would just reserve my opportunity to renew that objection when Ms. Ramas comes up.

CHAIRMAN GRAHAM: So you're saying that Ms. Ramas was asked a question that you objected to?

MR. McGLOTHLIN: Correct.

CHAIRMAN GRAHAM: Okay. When she comes up, we can deal with that at that time.

MR. McGLOTHLIN: Yes, sir.

CHAIRMAN GRAHAM: We will move 151 and 153.

(Exhibit 151 and 153 admitted into evidence.)

MS. KLANCKE: Chairman, would it be possible with respect to -- obviously we are all on the same page about the objection is standing, the objection is ongoing. Could we ask the parties to waive the foundation with respect to these depositions, the foundational questions just with regard to their authenticity?

MR. McGLOTHLIN: I believe so, so long as the underlying objection is noted for the record.

MS. KLANCKE: Certainly.

MR. MOYLE: That will save some time. We don't have an objection.

CHAIRMAN GRAHAM: Okay. 154, 155, and 156 all into the record.

(Exhibit Number 154, 155, and 156 admitted into evidence.)

MR. MOYLE: And just so we are clear, these are the depositions, not any exhibits or anything like that?

CHAIRMAN GRAHAM: Those are just the

depositions.

MR. MOYLE: Right.

MS. KLANCKE: That is staff's understanding, as well, not exhibits. If necessary, we will move those in separately at the time.

CHAIRMAN GRAHAM: Okay. Gulf, your next witness.

MR. GRIFFIN: Gulf calls Michael O'Sheasy.

CHAIRMAN GRAHAM: As the next witness is coming up, let's take a five-minute break until 6:00 o'clock.

(Recess.)

MR. GRIFFIN: Mr. Chair, this witness has yet to be sworn.

CHAIRMAN GRAHAM: Sir, if I can get you stand up and raise your right hand.

Are there any other witnesses here that have not been sworn? If I could also get you to stand up and raise your right hand.

(Witnesses sworn.)

CHAIRMAN GRAHAM: Thank you.

MICHAEL THOMAS O'SHEASY

was called as a witness on behalf of Gulf Power Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. GRIFFIN:

Q. Mr. O'Sheasy, would you state your full name and business address for the record, please?

A. Yes. Michael Thomas O'Sheasy. My business address is 5001 Kingswood Drive, Roswell, Georgia 30075.

Q. And by whom are you employed and in what capacity, please, sir?

A. Christensen Associates Energy Consulting, I'm the Vice-President in Charge of Costing and Pricing.

Q. And did you have occasion to submit Prefiled Direct Testimony consisting of 29 pages?

A. Yes, I did.

Q. Do you have any changes or corrections to that testimony?

A. No, I do not.

Q. If I were to ask you the same questions today, would your answers be the same?

A. Yes, they would.

MR. GRIFFIN: Mr. Chairman, we would ask that Mr. O'Sheasy's testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. O'Sheasy's testimony into the record as though read.

GULF POWER COMPANY
Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael T. O'Sheasy
Docket No. 110138-EI
In Support of Rate Relief
Date of Filing: July 8, 2011

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

A. My name is Michael T. 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 Bachelors of Industrial Engineering from the Georgia Institute of Technology in 1970. In 1974, I earned a Masters in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company -- 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 their last rate case filing, Docket No. 010949-EI, and in prior rate cases in Docket Nos. 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. 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 to 3) and Exhibit MTO-2 (containing Schedules 1.0 to 6.9) were prepared under my supervision and direction by the Costing, Forecasting & Energy Analysis Department of Southern Company Services (SCS), which is the service company in the Southern electric system (SES). 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 and sub-schedules that set forth the results of the cost-of-service study used as a basis for this case. Each schedule was prepared in the manner approved by the Commission in its final order for Gulf's last retail rate case, Docket No. 010949-EI, with one modification, which is to utilize the Minimum Distribution System to more properly account for customer-related costs. The rationale and justification for this change will be explained in my subsequent testimony.

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 jurisdictions. 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 certain groups of customers. 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 determining 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 prior cases, and provides the most accurate information.

Q. How was the cost-of-service study used by Gulf 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 McMillan 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. 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 Thompson 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 link between customer and company. This cost categorization or componentization can be viewed as: (1) customer-related, which are costs that vary with the number of customers or the fact that customers must be able to receive service; (2) energy-related, which pertain to costs that vary with energy consumption (kWh); and (3) demand-related, which are costs that are incurred to serve peak needs for electricity.

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.

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 costs incurred by each class as a major determinant."

There are three primary drivers in causing costs to be incurred by an electric utility which enable accurate cost allocation: (1) peak demands, (2) kilowatt-hours (kWhs), and (3) customers. Each of these three drivers has its own separate and appropriate allocators to spread its respective costs to the associated rate class and jurisdiction. 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 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 electricity consumed. The cost of the meter incurred by the utility to serve the customer does not vary with the quantity of electricity 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 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 ultimately be 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 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 Gulf's wholesale customers, all of which are under the jurisdiction of the FERC.

Sub-schedule 1.00 is the present rate summary for each rate class. Sub-schedule 1.01 provides an equal rate of return summary for each rate class under present revenue. Sub-schedule 1.10 reveals the overall rate of return for each rate class that will exist under the Company's proposed rates. Sub-schedule 1.11 presents the equal rate of return summary for each rate class under proposed revenue.

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:

- Residential Rate Class
- 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 class within the retail jurisdiction. It includes Gross Plant Sub-schedule 2.10, Accumulated Depreciation Reserve Sub-schedule 2.20, Materials and Supplies Sub-schedule 2.30, Other Working Capital Sub-schedule 2.40, and Other Rate Base Items Sub-schedule 2.50. 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 provides the Analysis of Revenues. Schedule 4 displays the Analysis of Expenses. Sub-schedule 4.10 details the allocation of Operations and Maintenance (O&M) expenses to jurisdiction and rate classes. Sub-schedule 4.20 describes the Depreciation expense allocation, and Sub-schedule 4.30 presents the Analysis of Taxes Other Than Income Taxes. Schedule 5.0 contains the Table of Allocators and Percentages. The results of these various schedules are summarized in Schedule 1. Schedules 6.1 to 6.9 show 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 Gulf Witness McGee. He also provided total territorial supply and losses for annual energy and for demand. In addition, Mr. McGee provided annual energy sales, monthly coincident peak (MCP) demands, annual non-coincident peak (NCP) demands, and the average number of customers for the test year by rate class and voltage level. 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 transmission step-up substation and transmission line costs.

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 last 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. Mr. McMillan 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 last 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 were 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.

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

A. It is the same except for a request to employ the Minimum Distribution System methodology to identify and allocate customer-related distribution system costs.

Although the Company does not agree that the use of 12-MCP & 1/13 kWh is a better allocator of generation level costs than a pure 12-MCP allocator would be, Gulf nevertheless prepared its study in this case using the Commission-approved methodology. Gulf continues to believe that a pure 12 MCP factor for generation results in a more accurate cost allocation. However, using the Commission's preferred method does not result in major variances in cost allocation from the pure 12-MCP approach and does not significantly impair Gulf in designing efficient rates.

Q. Please explain why the Minimum Distribution System methodology is important to Gulf and its customers.

A. As I discuss in more detail later, some costs of the distribution system beyond the customer meter and service drop do not vary with customers' use of electricity. The Minimum Distribution System (MDS) methodology is necessary to accurately determine and allocate these customer-related distribution costs. The misclassification of costs that results from not using the MDS methodology sends misleading price signals to customers. This misclassification also results in different customer rate classes bearing more or less costs 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. 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 all distribution costs which do not vary with demand or energy 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 quantity 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. 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.

Also a recently published treatise, *Electricity Pricing: Engineering Principles and Methodologies* (2009), by Lawrence J. Vogt identifies the zero-intercept and minimum system analysis as standard methodologies for classifying distribution costs. 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. 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 only discusses 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 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.

Q. Can you give us some idea of the harm that can be caused by inaccurate cost classification?

A. 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 and consequently makes conservation and energy efficiency choices that overestimate the real costs avoided by the system.

Although some might argue that conservation and energy efficiency would subsequently be advanced by this costing flaw, I would argue that the "advance" is for the wrong reasons, and conservation and energy decreases in usage would fail to be cost-based and therefore not in the ultimate best interest of Gulf's customers. Some might argue that this flaw could make up for omissions of other energy costs that fail to show up in embedded revenue requirements. It would be very difficult though to quantify these possible omissions and know whether they were commensurate with the customer-related costs which had been shifted into a demand classification.

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 a true cost benchmark so rate excursions from true costs can be observed and considered. Otherwise, rate decisions will be based on inaccurate information about true cost responsibility and impacts.

III. MINIMUM DISTRIBUTION SYSTEM METHODOLOGY

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?

A. There are two common ways to do so: (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 of equipment is necessary. The cost of this minimum size equipment is then categorized as a customer-related cost. For example, suppose that a 10 kVa line transformer represents the smallest size transformer normally used. In this case the unit installed costs of a 10 kVa transformer would be employed as the basis for the customer cost of transformers, with the residual transformer costs treated as demand-related. This methodology, although logical, has a weakness because even the smallest standard size equipment such as the 10 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 method, Zero-Intercept (ZI) is an improved technique for determining customer-related costs that, by definition, removes any ability of carrying load. This avoids double counting of load with MDS.

Q. How does the Zero-Intercept method work?

A. The ZI method is based on a regression analysis of costs for several sizes of equipment in order to determine the zero capacity unit cost. The resultant regression equation is extrapolated back to a level of no-load. This can be observed in Schedules 6.1 and 6.2 of Exhibit MTO-2.

Q. 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 premises 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 the intrinsic customer-related cost of the equipment that is actually used.

Q. How does one account for inflation when developing the ZI regression equation?

A. Equipment is regressed and analyzed using current replacement costs. This is necessary since some equipment in service for Gulf has a more current vintage than others. Once the ZI unit costs for the customer-related piece are computed, these costs are multiplied by the number of units in service to develop the aggregate amount. The remainder of "current replacement cost" is the demand-related costs. This resultant split of replacement cost into a customer piece and a demand piece is then used to allocate the embedded vintage cost for the equipment into appropriate customer and demand component costs. This is done for all the various types of equipment which possess both customer-related and demand-related characteristics within their inherent make-up. Any equipment which has either a strictly demand-only make-up (for example substation equipment) or a strictly customer-only make-up (for example meters) is directly assigned to the respective component. An appropriate customer allocator then allocates customer-related costs to rate classes in the cost-of-service study. Demand-related costs are similarly allocated to rate classes using a demand-related allocator.

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

A. Distribution Accounts 365, 366, 367, and 368 use this ZI methodology. For FERC Account 364, we used the average of the smallest, most frequently used poles since the unit cost of different sized poles did not lend itself to regression analysis. 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 6.3 to 6.9 of Exhibit MTO-2.

Q. Are Account 369 (Service Drops) and Account 370 (Meters) usually classified as 100% 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.

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

A. Yes. In fact, two other operating companies in the Southern electric system, Georgia Power Company and Mississippi Power Company, use MDS to determine the customer-related costs. Some other utilities that employ MDS include Kentucky Utilities, LG&E, Tennessee Valley Authority (TVA), Wisconsin Public Service, and Virginia Electric Power.

Q. You mentioned earlier that use of MDS is a change from the direction set forth in Gulf's last rate case. Has this Commission ever approved MDS?

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

Q. What effect will recognizing the use of MDS have on the various rate classes?

A. Using MDS and including the resultant customer component in the distribution accounts will increase the costs allocated to the residential rate class and decrease the costs allocated to large business classes. However, this is appropriate, since it better reflects the cost to serve these customer rate classes. When determining the cost of providing service to customers, who benefits should not be the deciding factor – cost causation should. In the past when this customer component was not recognized, large business customers were inappropriately allocated higher costs than cost-causation would justify. Even though the MDS methodology causes cost allocation to decrease for large business customers and to increase for smaller customers, it does so for rational reasons and properly allocates the costs to those customers who caused them to be incurred by the utility.

Q. What effect does including this customer-related component have for seasonal homes and vacation apartments?

A For months in which seasonal homes and vacation apartments are unoccupied yet still in service, cost allocation would be higher in cost-of-service studies than if these customer-related costs were misclassified in the demand component. However, this is indeed proper since even during months of vacancy Gulf must have its distribution system ready to provide service whenever the renter arrives. The seasonal customer should have the same cost responsibility as the year-round resident for these customer-related costs.

Q. It appears that you have included a customer-related component only for distribution equipment and not for transmission and subtransmission equipment. Why shouldn't transmission and subtransmission include customer components?

A. One could make the argument that transmission and subtransmission should have customer components. However, equipment at the transmission and subtransmission is much larger and operates at higher voltage levels than does distribution equipment. Consequently, imputing a customer-related piece would likely result in a very small portion of the transmission and subtransmission being identified as customer-related. As a result, it has been common convention in the electricity industry to stop calculating a customer component at the distribution level.

Q. Does the NARUC manual propose a customer component for transmission or does it stop at distribution?

A. The NARUC manual stops at distribution for classifying costs as customer-related.

Q. Do you recommend MDS in spite of limited precedent in Florida for its use?

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.

BY MR. GRIFFIN:

Q. And did you have any exhibits to your testimony, sir?

A. I did.

Q. And those would have been Exhibit MTO-1, consisting of three schedules, and MTO-2, consisting of Schedules 1.0 to 6.9?

A. Yes.

MR. GRIFFIN: And, Mr. Chairman, I would note that MTO-1 has been identified on staff's hearing exhibit list as Exhibit Number 24. MTO-2 appears to have been omitted from the Comprehensive Exhibit List, so I believe we could just assign it the next available number, which I believe is 198.

CHAIRMAN GRAHAM: Staff, is there a reason why MTO-2 was omitted, or is that just an oversight?

MS. BARRERA: I believe it was an oversight.

CHAIRMAN GRAHAM: I couldn't hear you.

MS. BARRERA: It was an oversight.

CHAIRMAN GRAHAM: Okay. So, we will give MTO-2 Number 198.

(Exhibit Number 198 marked for identification.)

BY MR. GRIFFIN:

Q. Mr. O'Sheasy, Schedule 1 of your Exhibit MTO-1 lists the MFRs over which you have responsibility in this case, is that right?

A. That is correct.

Q. Okay. And do you have any changes or corrections to your exhibits or to any of those MFRs?

A. Yes. Commissioners, in the discovery process, we came across an anomaly with the revenues with Rate GS and the revenues with Rate GSD. And as a result, we modified those revenues and computed what the impacts would be on what we call the rate of return index. And I'd like to share those changes with you, if I could.

MR. GRIFFIN: And, Mr. Chairman, what we have proposed to do, those changes were discussed during Mr. O'Sheasy's deposition which took place on November 15th, and they were reflected in a late-filed exhibit to that deposition. For purposes of clarity and for purposes of cross-examination, we have prepared -- basically, we have taken that late-filed exhibit and provided copies under separate cover to the Commissioners and all the parties here, and if we could just mark that as a separate exhibit for purposes of the hearing, I think that that would be smoother.

CHAIRMAN GRAHAM: So we will label that as Exhibit 199.

MR. GRIFFIN: Yes, sir.

CHAIRMAN GRAHAM: And, once again, what is the title for that?

MR. GRIFFIN: That would be O'Sheasy Revised MFR Schedules E6A and E6B.

MS. BARRERA: For purposes of clarification, does that include Late-filed Exhibit Number 3 to the deposition and Late-filed Exhibit Number 16?

MR. GRIFFIN: No, it does not. It's simply the correction that he made to the MFR schedules.

MS. BARRERA: Okay.

(Exhibit Number 199 marked for identification.)

BY MR. GRIFFIN:

Q. Okay. And with the changes reflected in what has now been identified as Hearing Exhibit 199, other than that, do you have any other changes or corrections to your testimony?

A. No, I do not.

Q. Okay. With that, Mr. O'Sheasy, could you please provide a brief summary of your testimony?

A. Yes. First of all, thank you, Commissioners, for allowing me to speak with you today. I appreciate it very much. I'm serving in this filing as the cost of service witness for Gulf Power Company. I was their cost of service witness in their last two retail rate cases.

The purpose of my testimony is to explain how Gulf Power Company's cost-of-service study is correct and accurate and is based on cost causation revealing the cost of providing service to Gulf's customers. I have been integrally involved with the creation of these filed cost of service studies, and I have thoroughly reviewed them for reasonableness and accuracy.

One of the most important factors in determining the adequacy and the need to change rates is the cost of providing the product, and this is what a cost-of-service study is all about, determining the cost of providing electricity and doing so based on sound cost causation principles. When done well, cost of service will provide the revenue requirements for the retail jurisdiction and indicate the adequacy of the current retail rates.

As explained in my testimony, Gulf Power Company's filed cost of service is an objective and accurate cost determination of providing service. The reasons for this include the fact that, one, the company's studies are based upon sound, logical, and accepted principles of cause causation as evidenced by the fact that these costing methods are recognized techniques with the National Association of Regulatory

Utility Commissioners' Cost Allocation Manual. These allocation methodologies are some of the most widely accepted procedures in retail jurisdictions throughout North America, and they are accepted methodologies by the FERC. They produce stable consistent results. The methods are objective, fair, and balanced, not favoring any one particular customer group.

Where costs are known for a specific rate, we have assigned them in our cost-of-service study. Where costs are shared and serve multiple rates, these common costs have been allocated upon cost-causative allocators, which provide that whoever caused the cost to be incurred is responsible for those costs.

These allocation methodologies mirror how the company plans and operates its system to serve growing peak demand and replace aging equipment. The studies filed in this proceeding are nearly identical to those filed and approved in Gulf Power's last retail rate filing. Gulf Power is requesting approval of its cost of service study as it did in 2001, its last retail rate case, requesting the recognition of the minimum distribution system, which I will refer to as MDS, for the separation of distribution accounts, and to demand and customer components. This requested cost-of-service study is the same as that previously accepted by this

Commission except for the inclusion of the MDS. We continue to believe that MDS is an important element in order to accurately allocate distribution cost. Use of MDS is a better method to determine the distribution cost of serving customers. The logic and rationale for MDS are explained in my testimony and exhibits. This improvement using MDS will provide a complete and accurate cost of providing service.

As required, we have also filed a cost-of-service study without MDS. The only difference in the two studies is with and without MDS. The benefits of these studies can serve as a platform to judge the adequacy of the retail rate request, they can be used as an efficient guide to rate design, and they can reveal cross-subsidies.

Finally, these rates influenced by this cost-of-service study can send cost-based price signals encouraging the efficient use of electricity. In conclusion, Gulf Power Company's filed cost-of-service study methodology is sound, accurate, reasonable, and fair, and we recommend that it be accepted by this Commission.

That concludes my oral summary.

MR. GRIFFIN: We tender the witness.

CHAIRMAN GRAHAM: Mr. Sayler.

MR. SAYLER: The Office of Public Counsel has taken no position on his issues and, therefore, we have no cross-examination for this witness.

CHAIRMAN GRAHAM: Fantastic. Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. I have just a few questions for you, Mr. O'Sheasy. As you mentioned in your opening, you are the witness here that was responsible for the preparation of the cost of service studies, correct?

A. Correct.

Q. If you would turn to your testimony on page -- turn to Page 16, please, Line 14, 14 and 15, actually.

A. Which page did you say?

Q. It is Page 16, and actually let's begin at Line 11. I'm going to talk about that paragraph for a moment.

A. All right.

Q. And in that paragraph you say the company does not agree that use of the 12-MCP and 1/13th kWh is a better allocator of generation level cost than a pure 12-MCP, correct?

A. Correct.

Q. And what is your basis for that statement?

A. Gulf Power Company is -- well, 12-MCP is an ideal allocator for Gulf Power Company. Gulf Power Company serves its peak loads throughout every month of the year. Even though Gulf is a summer peaking utility normally, what they do is they plan their scheduled maintenance outside the peak season such that they attempt to levelize their operating reserves year-round. In fact, for the test period their operating reserves for the winter period are less than their operating reserves in the summer peak period. In addition to that, the winter loads come up a lot faster than the summer loads do. The 12-MCP allocator, which we believe is best for Gulf Power Company, it handles the different generation technologies which Gulf has.

We also employ -- the FERC has three tests that they ask utilities to conduct to see which is the best allocator for production plant. We conducted those three tests and 12-MCP passed with flying colors. It's a commonly used technique throughout the industry. It handles average fuel clauses well. It allocates costs to all rate classes. It also matches perfectly the wholesale and retail split. What Mr. McMillan referred to, we allocate the total cost to retail and wholesale on 12-CP, and to do so within the retail jurisdiction, as I was saying is a better allocator, marries up very nicely with that aspect to it.

The 12-MCP and 1/13th, that 1/13th piece is allocated basically throughout the year. Well, the 12-MCP does the same thing. It allocates costs throughout the year. So we don't see where the 1/13th is necessary. We think that the 12-MCP as a stand-alone allocator is ideal for Gulf Power Company.

Now, as it turns out, the 12-MCP, or the pure 12-MCP, or the 12-MCP and 1/13th, the results are not dramatically different from either one. So we didn't take exception to using 12-MCP and 1/13th as an issue. But as I indicated in my testimony, we do believe it is a better technique.

Q. So if I understand your testimony, you have not filed a cost-of-service study with the pure 12-MCP, correct?

A. Correct.

Q. But would it be possible for you to do so if that were the Commission's decision?

A. Yes.

Q. You mention, I think, in your summary, and we have had a lot of discussion during the hearing about the use of the MDS as part of the cost-of-service methodology.

A. Yes.

Q. Have you been here for some of those discussions?

A. Yes, I have.

Q. Okay. And I think you said in your summary that you have filed one study with MDS and one study without it?

A. That is correct.

Q. And I also understood you to say that the company prefers and believes that the more appropriate approach is to use the study that you filed with MDS, correct?

A. That is correct.

Q. And can you tell me why that is?

A. We think it's a sound more logical way to allocate distribution cost. We firmly believe that a portion of distribution cost, distribution accounts is based upon the requirement to enable service to our customers. We have to have a system in place, a pathway, if you will, that will allow us to provide service regardless of the demands and the energy that are required to serve our customers. So it's that connectivity, if you will, that ability to provide service that we think is an important customer element of the distribution function, and we think would be better allocated, that portion would be better allocated to customers on a customer-related allocator.

Q. Mr. O'Sheasy, is it your understanding that as to the parties in the case, they either support the MDS methodology or they have taken no position on it?

A. I really don't know. I haven't necessarily examined what the parties' positions are on it. I'm sure that there is varied opinions on it.

Q. Let me ask you one more question. It's still in the MDS vein. Let me ask you, in your view does the use of the MDS methodology inappropriately shift costs from one group of customers to another?

A. Let me make sure I understood your question. I'm going to paraphrase it.

You asked in my opinion does use of the MDS inappropriately shift costs from one rate class to another?

Q. Yes, sir.

A. And if that is the question, no, I don't think it inappropriately shifts costs, I think it appropriately shifts costs.

Q. And why is that?

A. Because it better reflects cost causation. As I was implying, there is a portion of the distribution plant in place that is customer related, and we need to allocate that on a customer-related allocator. To do so otherwise, like, for example, with a demand allocator, does not follow cost causation as well as a customer allocator would do, so it is not as efficient in allocating cost.

MS. KAUFMAN: That's all I have. Thank you.

CHAIRMAN GRAHAM: Major Thompson.

MAJOR THOMPSON: FEA agrees with Mr. O'Sheasy's study, and we have no questions.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: No questions, Mr. Chairman. Thank you.

CHAIRMAN GRAHAM: Staff.

MS. BARRERA: We have a few questions.

CROSS EXAMINATION

BY MS. BARRERA:

Q. Ms. O'Sheasy, as Vice-President for Christensen Associates and Consulting for Gulf Power you are Gulf's witness regarding Issue Numbers 6, 106, and 107, is that correct?

A. That is correct.

Q. Could you please turn to Exhibit Number 199, which is the revised MFR Schedule E6A and E6B, and specifically turn to Page 4 of 7.

A. Apparently, I don't have the right copy. My page numbers don't go to 4 of 7. Can someone hand me another copy?

MS. BARRERA: This is the copy that was handed to me by Gulf counsel marked as Exhibit 199.

THE WITNESS: Okay. I'm sorry, I missed it. You're right, I have it. It is 4 of 7.

BY MS. BARRERA:

Q. Okay. Now, can you explain what this page of 4 of 7 on the revised cost of service information, what this exhibit represents?

A. First off, it represents the cost-of-service study with minimum distribution system. Secondly, it represents the proposed increase in rates. And, thirdly, it represents an equal rate of return for each one of Gulf's rates.

So if you will look at Lines 1 through 13 on that page, that's basically the proposed revenue requirement for each rate broken down by those functional categories that you can see in the description column, and it represents the revenue requirements under the proposed rates. So that revenue requirement would be the amount of money that Gulf needs to collect from sales to achieve their proposed revenues. So it would cover their expenses, it would cover an equal return on investment for each rate class. And so that's basically what it represents broken down by function. Then if you will look at the billing units in Rows 14 through 18, you see the billing units for the test period. And then if you look at Rows 19 through 29, you will see the revenue requirements divided by the billing units to give you unit cost by rate by component.

Q. Looking at Line Number 13, Column 4, where it says rate class residential, and then Line Number 13, total revenue requirements. You have the amount listed as $324,381,000, is that correct?

A. That is correct.

Q. Okay. And that would be the revenue collected from the residential class, in other words, the individual customers?

A. That is what Gulf would like to collect under proposed rates from the residential class if we have an equal rate of return for each one of the rate classes.

Q. And that's under the minimum distribution system?

A. It is.

Q. Okay. Now, let's look at Page 7 of 7 in that same exhibit.

A. Yes, ma'am, I'm there.

Q. Okay. Can you describe what this exhibit is, what this page is about?

A. It's the same thing that I just described except without the minimum distribution system.

Q. Okay. This is using the present system?

A. Yes.

Q. Okay. Would you look at Line 13, total revenue requirement, and then again to Column 4, rate class residential.

A. Yes.

Q. And is it correct that the total revenue requirement using the non-MDS method is 316,938,000?

A. That is correct.

Q. So doing some math, which, you know, as a lawyer, I don't necessarily do all the time, using MDS and not using MDS causes an increased revenue requirement to the residential class of 7,443,000. In other words, it raises -- using MDS, the revenue requirement is higher by $7.4 million, is that correct?

A. Yes. I didn't do the math, but I'm sure you're about right. Yes, I would agree with what you said.

Q. Someone else did the math for me, too. But it looks good.

A. Someone told me don't ever do math while you are up on the witness stand, so I would prefer not to do it.

Q. No question. When you do the cost-of-service study, using the MDS system as well as the non-MDS system, you have a certain pot of money that is a revenue requirement that is the total number across all the classes, is that correct?

A. Yes.

Q. Okay. And that pot of money is distributed differently amongst each class, isn't it?

A. Well, when you say it's distributed differently, there are allocators that allocate this cost to the different classes, and different classes get effected in different ways depending on the allocator.

Q. Okay. And the cost of cost-of-service study you prepared in this case show a decrease in distribution costs?

A. I don't understand the question.

Q. Okay, strike it. And you would agree, wouldn't you, that in terms of numbers of customers, Gulf, like most utilities, has many more residential customers than commercial and industrial customers?

A. Yes.

Q. And would you agree that in terms of numbers in the GS class, the costs allocated to the GS class, which is small businesses, are higher using the MDS system than using the non-MDS system?

A. Yes.

Q. So to summarize your testimony, if you used the MDS system, the utility's total revenue requirement is higher than without using the MDS system. And, on top of that, the cost is shifted to the individual residence and the individual small businesses and provides a service to the large commercial and industrial customers?

MS. KAUFMAN: Mr. Chairman, I am going to object to that question. First of all, it was compound, and I think it misstates what Mr. O'Sheasy said.

MS. BARRERA: Well, I'm asking you.

CHAIRMAN GRAHAM: If you can break that question down a little bit.

MS. BARRERA: Yes.

BY MS. BARRERA:

Q. In the MDS study, using the MDS methodology, does the MDS methodology and non MDS, comparing that to the non-MDS methodology, is the cost of the distribution system shifted from the commercial customers, the small commercial customers and residents to industrial? I mean, I'm sorry, shifted from the industrial and large commercial to individual residents and small businesses? Do you understand?

A. I hate to use -- I understand what you're asking. I hate to sue the word shifted, because that implies I'm doing something shifty, and I'm not doing that.

CHAIRMAN GRAHAM: If I can get you to restate her question, and then answer it.

THE WITNESS: Yes. Is it true that under the MDS methodology the cost of providing distribution plant for residential and small commercial is higher than the cost of providing distribution plant without using the MDS.

MS. BARRERA: Thank you.

THE WITNESS: And if that's the question, then I would agree. It is, but for the right reasons. It's not an issue in my mind of shifting, it's an issue of revealing what is the true cost of providing the product to each one of those rate classes. And the MDS method does a better and more true job of revealing the cost of providing service to residential, small commercial, and all the rate classes.

CHAIRMAN GRAHAM: Ms. Kaufman, do you still object to that question?

MS. KAUFMAN: No, I don't, Mr. Chairman. Thank you.

CHAIRMAN GRAHAM: Thank you.

MS. BARRERA: I have no more questions.

CHAIRMAN GRAHAM: Commissioners?

Commissioner Brown.

COMMISSIONER BROWN: Thank you.

Good evening.

THE WITNESS: Good evening.

COMMISSIONER BROWN: In your direct testimony you mention other electric utilities that use the MDS methodology. Do you know of any Florida electric IOUs that use the MDS methodology currently?

THE WITNESS: Not IOUs. I am familiar with CHELCO, but that is not an IOU. I'm not familiar with any other IOUs in Florida.

COMMISSIONER BROWN: And referencing -- I can't pronounce that case, but I do have it before me, and the case identified -- I'm assuming, first, that you are familiar with that case?

THE WITNESS: Yes, I am.

COMMISSIONER BROWN: And how do you pronounce it?

THE WITNESS: I call it CHELCO, but I may be wrong.

COMMISSIONER BROWN: Okay. It had four unique characteristics that justified the use of the MDS methodology, correct?

THE WITNESS: That is correct.

COMMISSIONER BROWN: And this is the only case that this Commission has allowed the MDS methodology, right?

THE WITNESS: I believe that's correct.

COMMISSIONER BROWN: Are those four unique characteristics present with Gulf, with regard to Gulf?

THE WITNESS: Let me expound on those four characteristics, because it's hard to say yes or no to that question. One of the characteristics was density. Another characteristic -- well, let me speak with to density real quick. Density is obviously the number of customers that you're serving versus your distribution network. And I believe CHELCO was asking for a $24 customer charge. Gulf is requesting -- their proposed charge is -- not their proposed charge, excuse me, their proposed unit cost is $20 per customer. So you can see that there is a difference there in the unit cost that is driven by density.

However, density is not what pushes cost. It is not the primary driver of what causes cost to be incurred. The primary drivers that cause costs to be incurred for Gulf, CHELCO, or any utility, electric utility that I'm aware of is customer-related, demand-related, or energy-related. Secondarily to that is how dense your customers are behind those three primary components.

But the point is, regardless of the unit cost, whether the unit costs are $24 a customer, or $20 a customer, or $10 a customer, a cost to service analyst should still strive to allocate costs correctly and based on cost causation. Whether the unit costs are high or low shouldn't affect that allocation.

So I will try to be quick. Gulf doesn't have the density issue that CHELCO would have. But I don't think that is a factor, in my opinion, whether you choose to use MDS or not. Another reason that was explained in the CHELCO decision was rural versus urban. No doubt CHELCO is more rural than Gulf is. Although Gulf does have rural customers, but the point here that CHELCO was making, I believe, was that because of the rural nature of their customers the revenue stream from sales is volatile, it goes all over the board. And if you have a large customer charge it tends to stabilize that revenue stream.

Well, that is a rate design issue. That is really not a cost of service issue, the stabilization of revenue. And Gulf, too, has rural customers. Gulf has seasonal customers that come and go. So in my opinion, the seasonality of a rural -- well, I shouldn't say -- rural versus urban seasonality, that's a factor, but, once again, I don't think that should rule in how you allocate costs.

Thirdly, CHELCO was mentioning something about we have got more accounts than we have customers, for example. And the example they were using was, let's just say that you have got this fictitious customer, George Burdell, and he owns a farm, and he wants to light up his barn. Well, he has got a choice. He can ask CHELCO to wire up the barn from their distribution system, or he can hire an electrician to come behind his meter and wire up that barn. Well, he can save money if the customer charge is low and he gets CHELCO to add another account rather than hire an electrician to wire from behind his primary meter at his house to the barn. So that is what he does.

So that is why CHELCO was saying we need a customer charge that discourages that to better reflects cost. And to me, once again, that is a rate design issue and it's a good issue. The rate design should reflect cost. A customer charge should reflect cost.

Finally, the last CHELCO issue was they were experiencing financial plight. They had a negative rate of return. Thank goodness Gulf does not have a negative rate of return, although it is quite low. 3.64 is quite low, and that is what we are here about is to prevent the cart from falling into the ditch. So rate of return is an issue with Gulf Power, too.

So this is a verbose way of saying, Commissioner Brown, that we do have some similarities, we have some dissimilarities. But bottom line, even if we matched up perfectly or we didn't match up, I think there is a lot more important issues as to whether you employ MDS or not beyond those four elements that were noted in the CHELCO decision.

COMMISSIONER BROWN: Thank you for your thorough analysis. I did want that on the record. So thank you.

THE WITNESS: You're welcome.

COMMISSIONER BROWN: That's all.

CHAIRMAN GRAHAM: Mr. O'Sheasy, the fictitious customer, was that George P. Burdell?

THE WITNESS: Yes, it was. You're familiar with him, also.

CHAIRMAN GRAHAM: I would say congratulations on your choice of undergrad institutions.

THE WITNESS: Well, thank you; and congratulations to you, too. It's an honor to speak in front of a Georgia Tech graduate.

CHAIRMAN GRAHAM: Thank you.

Redirect.

MR. GRIFFIN: No redirect.

CHAIRMAN GRAHAM: Okay. Exhibits.

MR. GRIFFIN: We would move 24, 198, and 199.

CHAIRMAN GRAHAM: 24 into the record. 198 and 199 into the record.

(Exhibit Numbers 24, 198, and 199 admitted into the record.)

CHAIRMAN GRAHAM: Mr. O'Sheasy, thank you very much for your testimony.

THE WITNESS: And thank you, sir, for allowing me to speak.

CHAIRMAN GRAHAM: Your next witness.

MS. BARRERA: Excuse me, Commissioner. We would like to move the exhibits to the deposition into the record, the ones that were not included.

CHAIRMAN GRAHAM: What are you moving into the record?

MS. BARRERA: I'm looking at Deposition Page 4. There is a list of 13 exhibits. It would be Exhibits 1, 2, 4 through 13, without Exhibit 3, which is has already been placed into the record by Gulf.

CHAIRMAN GRAHAM: One more time. Your exhibits are in the deposition?

MS. BARRERA: Yes. They are part of the deposition. They are exhibits to the deposition which has already will be placed into the record, except that I -- unless I am mistaken, I understood that the deposition only was being introduced --

CHAIRMAN GRAHAM: That's correct.

MS. BARRERA: -- and not the exhibits. So at this time I would like to move the exhibits to the deposition into the record.

CHAIRMAN GRAHAM: And what exhibits?

MS. BARRERA: These are listed as Exhibits 1 and 2, and then 4 through 13 as listed on Page 4 of the deposition transcript.

CHAIRMAN GRAHAM: Is there any added objections to those exhibits in the deposition?

MS. KAUFMAN: Yes, we do have an objection to some of the exhibits, and I can go through them one-by-one.

CHAIRMAN GRAHAM: Please.

MS. KAUFMAN: I think the first one that Ms. Barrera mentioned is Exhibit Number 4, which is, as I understand it, a few pages out of some sort of textbook that at his deposition as I recall Mr. O'Sheasy said he was unfamiliar with and that he had never seen it. So I don't think there is any -- no foundation has been established for entering this into the record.

The second exhibit that we object to is

Deposition Exhibit 9.

CHAIRMAN GRAHAM: Hold on just a second.

MS. KAUFMAN: Oh, I'm sorry.

CHAIRMAN GRAHAM: I need for you to hand these exhibits out so I know what she's talking about.

MS. BARRERA: Okay. Can we take a break for a minute?

CHAIRMAN GRAHAM: We can come back to this.

MS. BARRERA: Yes.

CHAIRMAN GRAHAM: Okay.

MR. GRIFFIN: Mr. Chair, before we go to Mr. Thompson, Gulf would ask that Mr. O'Sheasy be excused. He does not have any rebuttal in this case.

CHAIRMAN GRAHAM: If there is no other reason to hold Mr. O'Sheasy?

MR. SAYLER: Even though this is not our issue, if Mr. O'Sheasy is excused and no longer a part of the hearing, then there may be issues with objections to his exhibits or laying the foundation for those exhibits and it may cause an issue for staff potentially. I just wanted to mention that.

CHAIRMAN GRAHAM: I think we probably should wait until staff passed out those exhibits and we decide what we're going to do one way or the other before we excuse Mr. O'Sheasy.

MR. GRIFFIN: And that is perfectly fine. With respect to Witness Burroughs, I know that the Chairman had indicated possible excusal of Burroughs if McMillan answered the questions that were deferred. We believe that's the case.

CHAIRMAN GRAHAM: If there's no objection to excusing Mr. Burroughs.

MS. KAUFMAN: I have no objection.

MR. SAYLER: No objection.

CHAIRMAN GRAHAM: Staff?

MS. BARRERA: No objection.

CHAIRMAN GRAHAM: Then he can be excused.

MR. GRIFFIN: Thank you.

MR. WRIGHT: Mr. Chairman, while we are standing down and staff are pulling together the exhibits --

CHAIRMAN GRAHAM: Actually we're getting ready to call the next witness, but go ahead.

MR. WRIGHT: Simply so I can keep my records straight for this case --

CHAIRMAN GRAHAM: Sure.

MR. WRIGHT: -- are we going to get hard copies of Mr. O'Sheasy's deposition exhibits that staff wants moved in, and if so, are they going to be given a regular exhibit number, or -- I'm just trying to understand where they're coming into the record, if they come in.

CHAIRMAN GRAHAM: Well, what I need for staff to do is to hand those hard copies out, and then at that time we can decide how we are going to identify them for the record.

MR. WRIGHT: Thank you very much, Mr. Chairman.

MR. GRIFFIN: Gulf would call James Thompson.

CHAIRMAN GRAHAM: Thank you.

JAMES I. THOMPSON

was called as a witness on behalf of Gulf Power Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. GRIFFIN:

Q. Mr. Thompson, you were in the room a minute ago when Mr. O'Sheasy was sworn?

A. I was.

Q. And you were sworn, also?

A. I was.

Q. Would you please state your full name and business address, please?

A. I am James I. Thompson. My business address is One Energy Place, Pensacola, Florida 32520.

Q. And by whom are you employed and in what capacity?

A. I am employed by Gulf Power as Supervisor of Pricing and Load Research.

Q. And have you filed Direct Testimony in this case consisting of 21 pages and Supplemental Direct Testimony consisting of two pages?

A. Yes.

Q. Do you have any changes or corrections to that testimony?

A. No.

Q. If I were to ask you the same questions today, would your answers be the same?

A. They would.

MR. GRIFFIN: Mr. Chairman, we would ask that Mr. Thompson's Direct and Supplemental Direct Testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Thompson's Direct and Supplemental Direct into the record.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
James I. Thompson
Docket No. 110138-EI
In Support of Rate Relief
Date of Filing: July 8, 2011

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

A. My name is Jim Thompson, and my business address is One Energy Place, Pensacola, Florida 32520. I am employed by Gulf Power Company (Gulf or the Company) as Supervisor of Pricing and Load Research.

Q. What are your responsibilities as Gulf's Supervisor of Pricing and Load Research?

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 also supervise the planning, collection, analysis and reporting of load research information for Gulf.

Q. Please describe your educational and professional background.

A. In December 1977 I graduated from The Georgia Institute of Technology, earning a Bachelor of Science in Industrial Management with honor. In early 1978, I joined the NCR Corporation as a sales representative out of that company's Atlanta office. I joined Gulf in 1980 as an analyst in Gulf's Rate Department. In 1988 I became a member of Gulf's marketing organization. In 1997 I assumed the duties of Corporate Accounts

Manager within Southern Company's Corporate Accounts organization. I moved into my current position in 2000. Throughout, I have been involved with various functional activities including program development and evaluation, market research, economic development, load research and market planning. For most of my career, I have been involved in the pricing of Gulf's energy services.

Q. Have you previously testified before the Florida Public Service Commission (FPSC or the Commission)?

A. Yes. I testified on behalf of Gulf in support of its Standby Service rate, Docket No. 931044-EI, and in support of Gulf's request for approval of its Commercial/Industrial Service Rider, Docket No. 951161-EI. I also testified as the rate design witness in Gulf's last base rate case proceeding, Docket No. 010949-EI.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the rates that Gulf has developed to recover the increased revenue requirement in a way that is fair and equitable to our customers. I also explain and support other non-revenue related tariff changes proposed by Gulf to improve our overall tariff offerings.

Q. Do you have an exhibit to which you will refer in your testimony?
A. Yes. Exhibit JIT-1, Schedules 1 through 3, 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 the sponsor of any Minimum Filing Requirements (MFRs)?
A. Yes. These are listed in Schedule 1 of my Exhibit JIT-1. 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 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, or 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 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 differences 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 also include a Customer Charge, or Base Charge, which is a fixed amount each month to reflect the costs of supplying service that do not vary with usage. Another price component is the Energy Charge, which reflects costs associated with providing the amount of electricity consumed throughout the month. Rate schedules for medium and large business customers may also include a Demand Charge component, which reflects the Company's cost of supplying service at the highest level of consumption required by those customers. Finally, in addition to the specific prices, rate schedules contain terms and conditions. Together, the prices, terms, and conditions describe the way customers' monthly bills are determined.

Q. Is the overall construct of Gulf's rate schedules like that of most other electric utilities?

A. Yes. Gulf's tariff is similar in terms of having separate rates for different customer classes, and using the most common components of rates, as described above. However, there is an element of Gulf's overall tariff that is perhaps different from many other retail electric suppliers. Many utilities determine the applicability of rates – that is, what class or type of customer the rate is applied to – according to the nature of the customer's use of electricity. For example, some utilities have rates that apply only to commercial customers, or only to industrial customers. It is also common for electric utilities to have rates applicable for specific end-uses of electricity, such as "farm rates" or "school rates." In contrast, Gulf's retail rate applicability is generally determined by objective criteria that do not include consideration of how the customer is using the service. Rather, determination of the applicability of rates is made based on the size of the electric service needed, the time that service is supplied, and the voltage level of the service provided. These are all objective characteristics that are measured or determined by a meter.

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, equity, and value of service. 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.

Q. Before getting into the details of how you developed the specific rates in this case, is Gulf proposing any non-revenue change to its Tariff that would affect all rate classes?

A. Yes. We are proposing to change the name of the rate component that has been called the Customer Charge by relabeling it as a Base Charge. This change in terminology better reflects the purpose of this monthly, fixed charge. This charge exists to reflect the fact that a certain base level of costs is incurred by Gulf to provide electricity independent of the amount of service consumed.

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

$93,504,000. 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 20.7 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 customary 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 13.8 percent to 28.0 percent.

Q. Please explain why the percentage increase proposed for the residential class is larger than the overall average increase.

A. The present rate summary in Mr. O'Sheasy's cost-of-service study reveals a rate of return for Gulf's residential class that is significantly below the overall retail average rate of return. A larger increase is needed to bring the return on investment for this class closer to the overall retail average at the new proposed revenue level.

Q. Please explain the information labeled "Indexed" 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. For example, without rate relief, the return provided by the residential class is only 93 percent of the Company's overall retail rate of return. After the rate increase, the return for the residential class would be 102 percent of the Company's retail average.

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 which achieve the overall proposed revenue level for that rate class, we have included an increase to the Customer Charge rate component and renamed that component the Base Charge. We also propose an increase to the energy charge components of residential rates.

Q. Why are you proposing to increase the residential Base Charge?

A. The customer-related costs from the cost-of-service study are significantly higher than our current residential Base Charge of $10 per customer, per month. There are important reasons for ensuring that, to the extent practical, the costs of providing service to customers that do not vary with the amount of consumption are recovered from fixed Base Charges rather than from energy or demand charges. If these costs are included in the unit prices of energy consumed, then otherwise successful conservation efforts could result in revenue decreases for Gulf which exceed the associated cost savings. This would, in turn, increase or accelerate Gulf's need for future base rate increases.

Also, each month Gulf has thousands of residential customer accounts whose monthly electric usage is zero. Customer-related costs that are included in energy charges are not recovered at all from those customers. Thus, intra-class equity, or fairness, is better served by having Base Charges that cover those costs which are unrelated to amounts consumed.

We have proposed to increase the Base Charge for Gulf's standard residential rate, Rate Schedule RS, from its current $10.00 per customer per month to $15.00. The cost-of-service study shows that customer-related costs could support an even higher Base Charge. However, we have limited the increase in the Base Charge to 50 percent above the current level in order to maintain rate stability.

The Base Charges are important rate components which recover those costs that are not related to the amount of electricity consumed. The increased residential Base Charge is reasonable and represents an improvement in our pricing structure.

Q. What other changes are proposed to residential rates?

A. Rate Schedule RSVP is the rate that accompanies Gulf's residential critical peak pricing program called Energy Select ®. It includes a Base Charge and a four-tiered energy charge. The four energy charges differ based on time of day and season. Three of the price tiers are applicable to known time periods which are referred to as high, medium, and low price periods. The fourth price tier is the critical price which is invoked with as little as an hour's notice based on certain conditions. Critical price periods are limited, however, to not more than two hours in duration. Critical price periods are designated when conditions, typically weather, cause peak demand to reach very high levels. The critical peak price serves, through customer load response, as a critical peak demand management tool.

Because the base rate component of all four price tiers has remained fixed since Gulf's last rate case, while the cost recovery factors applicable to those prices have changed, we have experienced a detrimental change in the relationships among those price tiers. The price relationships now do not provide for customer savings opportunities that they should. Therefore, we are proposing in this case to improve these price tier relationships.

Q. What changes do you propose to improve the Rate RSVP price tier relationships?

A. Gulf proposes to use the Energy Conservation Cost Recovery (ECCR) Clause to achieve the price differentials among the four price tiers. This is in contrast with the previous approach for Gulf. Until now, the price differentials among the tiers were achieved by setting different base rate energy charges. In the proposed method, the base rate energy charges for all four price tiers are set equal to the base rate energy charge in Gulf's standard residential rate, Rate Schedule RS. The differentiation in the overall prices for each of the tiers will be achieved through applying different ECCR charges to each tier, with those ECCR charges determined in the ECCR docket on an annual basis.

Q. Please explain how the differentiation in the prices would be achieved through application of the ECCR charges to each tier.

A. First, the base rate energy charge for all four price tiers would be set, in this rate case, the same as the Rate Schedule RS base rate energy charge. Then, each time the ECCR charges are set or modified for Gulf, those cost recovery charges would be established for each of the four price tiers of Rate Schedule RSVP. We could expect the ECCR factors for the lowest price tiers to be small or even negative amounts. Conversely, we could expect the ECCR factors for the higher price tiers, P_3 and P_4, to be significantly higher. The result of this ECCR-driven approach toward setting and maintaining the relative energy prices for the four-tiered Rate RSVP is the ability to offer Energy Select ® program participants a rate which complements the program's objectives.

Q. Has the FPSC previously approved such an approach?

A. Yes. The methodology we propose was approved by this Commission for Tampa Electric Company in Docket No. 070056-EG, Order No. PSC-07-0740-TRF-EG, issued September 17, 2007.

Q. What other improvements to Rate Schedule RSVP are proposed?

A. We propose to make a change to the Applicability section of Rate Schedule RSVP. The rate schedule subtitle will now include the phrase "Electric Vehicle Charging," and the Applicability section of the rate will specifically refer to electric vehicle charging. This new labeling indicates that the Energy Select ® program and Rate Schedule RSVP are well suited to at-home electric vehicle charging. Adding this information to the label on the rate schedule will help inform customers and others of the suitability of this rate for electric vehicle charging.

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 have proposed 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. Also, the proposed Base Charges are set at not more than a 50 percent increase above the current Customer Charges. Second, the overall base rate levels have been designed to achieve the requested revenue increase for these rate classes. Third, 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.

Q. Are there other changes proposed to the rates for small and medium size business customers that are aimed at improving customer satisfaction?

A. Yes. We have proposed to increase the breakpoint between Rate GS and GSD from 20 kilowatts (kW) to 25 kW. Currently, only those non-residential customers who have demands less than 20 kW are eligible for service under Gulf's Rate Schedule GS. We propose to increase this to 25 kW. Customers with demands at or above the breakpoint are not eligible for service under Rate Schedule GS. Instead, they are served under a choice of standard or time-of-use rate schedules for medium size business customers.

Our data indicates that about 12 percent of Gulf's customers who are currently served on one of these rate schedules for medium size business customers have billing demands that are greater than 20 kW but less than 25 kW. Under the proposed rates, these smaller customers would be eligible for, and have the opportunity to choose, Rate GS, which does not include a demand charge component. This increased choice should improve customer satisfaction.

Q. Are you proposing to add any other rate options for business customers?

A. Yes. We are proposing a new critical peak rate option for medium and large size business customers who are served on time-of-use rates. This critical peak option will allow business customers to participate in a form of critical peak pricing. Structurally, this new option introduces a third demand charge for customers on the General Service Demand Time-of-Use (GSDT) and Large Power Time-of-Use (LPT) rates. This third tier demand change is in addition to the Maximum Demand Charge and On-Peak Demand Charge rate components currently found in these rates.

Q. Why is this new rate option proposed?

A. The on-peak pricing periods for Gulf's GSDT and LPT time-of-use rates are very broad. During the months of April through October, the on-peak period is from noon until 9:00 PM, Monday through Friday. The new option provides a narrowly defined critical peak period. Critical peak periods will be either one or two hours in duration and will be designated one business day prior to that critical peak period. The demand charge applicable to that critical peak period is higher than the On-Peak demand charge, but customers with load management abilities may be able to avoid, or substantially reduce, their demand during these short periods.

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 allocated to these rate classes. Rates with distinct demand charges have been developed preserving the basic relationships between demand and energy charges found in the current rates.

The companion time-of-use rates, Rates GSDT and LPT, have been designed following a technique established in Gulf's last rate case. 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.

As with residential rates and rates for small business customers, 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.

VI. OTHER TARIFF CHANGES

Q. Are you proposing any other tariff changes that do not have revenue impacts?

A. Yes, five types of changes are proposed. These changes are proposed to better serve customers, simplify rates, and to improve the forms used to transact business. Included are a change to the applicability threshold for Gulf's Real Time Pricing rate, simplification of the size requirement associated with Rate Schedule CIS (Commercial/Industrial Service) rate rider, simplification of some of the forms used with the outdoor service rate, elimination of Rate Schedule ISS and a number of ministerial changes which are intended to update portions of the tariff which have either become stale over time or are in need of clarification.

Q. What change is proposed for Rate Schedule RTP?

A. Rate Schedule RTP, Real Time Pricing, is currently available only to retail customers with demands of 2,000 kW or greater. We are proposing to lower this demand threshold to 500 kW.

Q. Why is such a change needed?

A. The 2,000 kW applicability threshold has been in place since the initial implementation of Real Time Pricing at Gulf in 1995. We have seen a steady increase in the number and type of customers purchasing from us under RTP since that time. More than half of Gulf's customers who meet the 2,000 kW threshold are now choosing to avail themselves of Real

Time Pricing. Our experience, metering and billing abilities, and the diversity of customers who like this option, indicate that it is time to open it up to more, and smaller, customers. Gulf presently has about 300 to 350 customers who meet the 500 kW threshold. Giving these additional customers the ability to use RTP to manage their electric usage should improve customer satisfaction.

Q. Moving to the Commercial/Industrial Service rate, Rate Schedule CIS, what change is proposed there and why?

A. One change is proposed. It is to simplify the minimum size requirement for "Qualifying Load" to make it 500 kW in all cases. This is a simpler size requirement than currently exists. The current size requirement treats new load and retained load differently. Under the current provisions, new Qualifying Load must be at least 1,000 kW of installed, connected demand, while retained Qualifying Load can be as small as 500 kW of metered demand. This simplification will make the rate easier for customers to understand and easier for Gulf to administer.

Q. Please describe the changes you propose to the Outdoor Services rate.

A. Rate Schedule OS covers outdoor lighting, facilities associated with outdoor lighting, and other unmetered non-lighting outdoor services. Similar to all other classes, we first update the OS rates to recover the portion of the total revenue requirement allocated to that class. In addition, we propose to modify Forms 4, 5, 19, 20 and 24, which are the "Lighting Pricing Methodology," the "Contract for Street and General Area

Lighting Service," the "Optional Relamping Service Agreement," the "Optional Up-Front Payment of Fixtures," and the "Customer-owned Lighting Agreement Without Relamping Service Provisions," respectively.

Q. Why are these modifications proposed?

A. We are proposing these modifications to accommodate Light Emitting Diode (LED) fixtures, to update the labor rate, and to simplify and reduce the number of forms necessary to transact lighting business.

Q. Do the changes just described affect the prices charged?

A. Only the change to the labor rate would affect prices charged. The other changes mentioned are intended to make it more efficient for our customers and employees to transact lighting business and specifically to accommodate LED fixtures.

Q. Are you also proposing a change to how Form 4 is used?

A. Yes. Form 4 is a template for lighting charges. It is a formula-based approach by which Gulf Power prices new lighting fixtures or associated facilities. Use of Form 4 for this purpose was approved in Gulf Power's last rate case.

It is our understanding, however, that Form 4 currently cannot be used to re-price existing fixtures or associated facilities. As discussed by Gulf Witness Neyman, we request approval in this case to use the Form 4 formulary methodology for this additional purpose. Lighting technology changes, vendor changes, and material cost changes frequently render prices of existing fixtures stale. The ability to re-price existing fixtures – up or down – as costs change would benefit lighting customers.

Q. Why are you proposing to eliminate Rate Schedule ISS?

A. Rate Schedule ISS is an interruptible standby service rate. Gulf has no customers on this rate; we have never had any customers on this rate; there are no customers on this rate in the test year; and we do not expect to have any customers on this rate in the foreseeable future. Further, Gulf has no FPSC approved maximum level of cost-effective non-firm load, which would be a pre-requisite for application of this rate. For all these reasons, Rate Schedule ISS should be deleted from Gulf's Tariff for Retail Electric Service. Doing so would remove an undue administrative burden associated with continuing to have such a rate in Gulf's tariff.

Q. You previously mentioned that Gulf is also proposing a number of ministerial types of changes to its tariff. What is the nature of these changes?

A. These changes are intended to update portions of the tariff which have either become stale over time or are in need of clarification. For example, Gulf is proposing to eliminate the 1970's era map of its service area located in Section I of the tariff and the 1960's era List of Communities Served in Section V of the tariff. In lieu of these provisions, Gulf is proposing to include a more general description of its service area on the title page of its tariff, in accordance with Rules 25-9.023 and 25-9.028, Florida Administrative Code. We are proposing to eliminate Form 11 titled "Contract for Time-of-Use Conservation Rate," because Gulf no longer offers this rate. We are proposing to modify the signature blocks on a number of standard forms to conform with the Company's current signature policies. We are proposing minor changes to sections of the tariff addressing underground electric distribution facilities to clarify that these provisions apply to both residential and commercial installations. There are a handful of additional minor changes, which should be self-explanatory.

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

A. Yes. 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 changes to any of its Miscellaneous Service Charges?

A. No. The costs incurred in providing those services are very close to the current fees charged, so no changes are proposed.

VII. 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; provide customers with additional options to manage their electric usage; enhance conservation efforts; and provide opportunities to improve customer satisfaction with Gulf. I have included all of the revised final tariff sheets in Schedule 3 of my exhibit.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Supplemental Direct Testimony of
James I. Thompson
In Support of Interim Rate Relief
Docket No. 110138-EI
Date of Filing: July 8, 2011

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

A. My name is Jim Thompson, and my business address is One Energy Place, Pensacola, Florida 32520. I am employed by Gulf Power Company (Gulf or the Company) as Supervisor of Pricing and Load Research.

Q. Are you the same Jim Thompson who has prefiled direct testimony in this docket in connection with Gulf Power's request for rate relief?

A. Yes.

Q. What is the purpose of this supplemental direct testimony?

A. The purpose of this supplemental direct testimony is to describe the rates Gulf proposes to use to achieve the requested interim revenue requirements, an increase of $38,549,000.

Q. Are you sponsoring any Minimum Filing Requirements (MFRs) related to the request for interim rate relief?

A. Yes. These are listed in Schedule 1 of my Exhibit JIT-2. The information contained in these MFRs is true and correct to the best of my knowledge and belief.

Q. How do you propose to implement the interim rate request?

A. The increase amount of $38,549,000 was provided to me by Gulf Witness McMillan. He has also provided me with the overall base rate percentage increase factor represented by this requested increase, which is 8.882 percent. The interim revenue increase is achieved by adjusting all base rate components of all rates by this percentage, so that all customers would experience the same percentage increases in their base rate bills. This method is also consistent with FPSC Rule No. 25-6.0435.

Q. Have you prepared the tariff sheets necessary to implement this interim increase?

A. Yes. The tariff sheets necessary to implement the interim increase are attached as Schedule 2 of Exhibit JIT-2.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

BY MR. GRIFFIN:

Q. And, Mr. Thompson, you have one exhibit attached to your Direct Testimony and one exhibit attached to your Supplemental Direct Testimony, is that correct?

A. I do.

Q. And those would be JIT-1 consisting of three schedules, and JIT-2 consisting of two schedules, is that right?

A. Yes, sir.

Q. And are you sponsoring any MFRs in this case?

A. I am.

Q. And those MFRs are identified in Schedule 1 of Exhibit JIT-1 and Schedule 1 of JIT-2, is that right?

A. Correct.

MR. GRIFFIN: And, Mr. Chairman, I would note that Exhibit JIT-1 has been identified on Staff's Comprehensive Exhibit List as Hearing ID Number 25.

CHAIRMAN GRAHAM: Okay. So noted.

MR. GRIFFIN: Exhibit JIT-2, like Mr. O'Sheasy's, appears to have been omitted from the Comprehensive Exhibit List.

CHAIRMAN GRAHAM: Staff, is there a reason why JIT-2 was left off the list?

MR. YOUNG: I think it's a clerical error, that's it.

CHAIRMAN GRAHAM: Okay. We will assign Number 200 to JIT-2.

(Exhibit Number 200 marked for identification.)

BY MR. GRIFFIN:

Q. Do you have any changes or corrections to your exhibits or MFRs, Mr. Thompson?

A. Yes.

Q. And what are those?

A. Starting with the Exhibit JIT-1, Schedule 2, I won't go through in great detail those changes, because they are simply the same changes that Mr. O'Sheasy referred to. Those changes are also repeated because I used some of those same numbers, those relative rates of return across the various rate classes in my Schedule 2 of Exhibit JIT-1. And so those same changes related to the anomaly that Mr. O'Sheasy discovered and corrected are reflected in my Schedule 2. Shall I go through those number by number?

CHAIRMAN GRAHAM: No, it's not necessary. I believe staff just passed out your revised Schedule 2 for JIT-2. I'm sorry, JIT-1. So, staff, is it best to give this an exhibit number and just add that?

MR. YOUNG: Yes, sir.

CHAIRMAN GRAHAM: So we will make this Exhibit 201.

THE WITNESS: And the other changes on -- Mr. Griffin also asked me about MFRs. The other changes on MFR Schedule E-8, the same commentary. These are residual changes simply repeating the same type of changes that Mr. O'Sheasy referred to because those numbers are also used on this schedule.

CHAIRMAN GRAHAM: I tell you what, we will make those both of those one exhibit number, which will be 201, and make it a composite.

(Composite Exhibit Number 201 marked for identification.)

BY MR. GRIFFIN:

Q. With those changes, Mr. Thompson, I would ask that you provide a brief summary of your testimony, please.

A. Thank you. Mr. Chairman and Commissioners, the purpose of my testimony is to present the package of retail rates that Gulf has developed to achieve the increased revenue requirement sought by the company in this case in a way that is fair, just, and reasonable. I also explain and support other nonrevenue-related tariff changes proposed by the company that will improve Gulf Power's overall tariff offerings and our pricing menu.

First, I address and explain rate design principles and methodology in general, explaining how Gulf Power Company's retail tariff is and isn't like that of other retail electric service suppliers.

Next, I cover the two basic steps in the rate design process starting with the allocation of the requested revenue increase to the various classes of customers served. Classes like residential, small, medium, and large business customers, and outdoor lighting. This allocation of the revenue increase has been done in order to move the rate of return for each one of those rate classes toward the overall retail average rate of return. In addition, fairness and other important and appropriate considerations have been included in the allocation of the overall revenue increase requested.

The second of those two basic steps in the rate design process is the design of the specific rates for each one of those rate classes. In this part of my testimony, I presented and explained the development of the individual components of the rates in our pricing menu. I have also covered tariff changes proposed that do not have revenue impact. These are changes that will allow Gulf Power to better serve customers, simplify rates, and improve the paperwork flow in our transactions with our customers. Included in this set of changes proposed is an extension to the use of our outdoor lighting pricing methodology.

Commissioners, there are benefits offered to our customers through this package of rates and associated tariff changes. The rates shown on the tariff sheets filed in this case will achieve the requested revenue requirement, including the increase sought. They represent fair, just, and reasonable pricing of Gulf Power's retail electric services. They provide customers with additional options to manage their electric usage, enhance our conservation efforts, and provide opportunities to improve customer satisfaction with Gulf Power. That concludes my summary.

MR. GRIFFIN: We tender the witness.

CHAIRMAN GRAHAM: Yes, sir.

Mr. Sayler.

MR. SAYLER: Same as before, Mr. Chairman. No questions for this witness from Office of Public Counsel.

CHAIRMAN GRAHAM: Sounds good. Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Chairman. I just have one or two questions.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. Good evening, Mr. Thompson.

A. Good evening, Ms. Kaufman.

Q. As I understand your summary, what you do is you take Mr. O'Sheasy's cost-of-service study and then you essentially translate it into the rates that are charged to the customers, is that correct?

A. Yes, adding in some other important considerations.

Q. Understood. I know that you were here during Mr. O'Sheasy's testimony, were you not?

A. I was.

Q. Okay. And that you heard our discussion about the MDS, correct?

A. Yes.

Q. And you heard some discussion about whether or not use of that shifts costs from one class to another inappropriately. Let me ask you your opinion on that?

A. The easiest way to describe it is I agree with Mr. O'Sheasy.

Q. Okay. And I just have one more question for you. Do you think that the use of the MDS -- well, let me back up and give you a little background. We have heard a lot of discussion and seen some exhibits in the case that have illustrated that Gulf has some of the highest industrial rates in the southeast region. Do you think that use of the MDS will help to make Gulf's industrial rates more competitive?

A. Yes.

MS. KAUFMAN: That's all I have. Good witness.

CHAIRMAN GRAHAM: Major Thompson.

MAJOR THOMPSON: No questions.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: No questions. Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Staff.

MR. YOUNG: Staff has a few.

CROSS EXAMINATION

BY MR. YOUNG:

Q. Good evening, Mr. Thompson.

A. Good evening, sir.

Q. A question for you. Gulf Power in this proceeding has proposed a percentage increase to the transformer discount which are similar to its proposed increase in demand charge, correct?

A. Yes.

Q. Can you please state the reason or reasons why Gulf is proposing this approach to changing its transformer discount in this proceeding?

A. Continuity. It is important that our customers who have invested in voltage transformation equipment, who have made capital investment in that equipment continue to get a continuous, a reasonable relationship in terms of the amount of the voltage discounts, the transformer ownership discounts, and the demand charges that they pay in the related rates. Those customers incur the ownership, operation, and maintenance cost of that equipment, and they should continue to see the associated discounts associated with the customers providing those voltage transformation equipment in a reasonable fashion.

The reason, therefore, that we have proposed to update the transformer ownership discounts by the same percentage as the associated demand charges in the rate is to preserve the continuity or the relationship between those two things. I think that is appropriate.

Q. Would you agree that another approach to establishing a transformer discount would be to base the discount on the estimated cost savings to the utility -- excuse me, base the discount on the estimated cost savings to the utility realized when a customer provides their own transformer equipment and service?

A. Yes.

Q. And would you agree that under the MSD cost-of-service study proposed by Gulf in this case that the transformer discount proposed by Gulf are higher than the estimated cost of service avoided when the customer provides their own transformer equipment and services?

A. I have not made a specific comparison of those two things. My recollection from seeing one of the interrogatory responses on that was that the two methodologies yield pretty close results. They lead us to very close end points. It's my opinion that the two methodologies are both reasonable. Because they lead to very similar end points that they are both reasonable and either is acceptable.

MR. YOUNG: Mr. Chairman, can we approach the witness?

CHAIRMAN GRAHAM: Sure.

MR. YOUNG: Mr. Chairman, what I'm handing out to the witness is a part of Staff's Exhibit Number 99, and it's Gulf's response to staff Interrogatory Number 110, Page 6 of 6.

BY MR. YOUNG:

Q. Mr. Thompson, if you could take a minute to look at this document, focusing your attention on Page 6 of 6?

A. All right, sir.

Q. All right. This response indicates that under the MSD and non-MSD cost study there is no cost basis for its current standby service or SDS transformer discount, is this correct?

A. I'm not sure.

Q. If you look at the bottom under C, the last two sentences starting, "However," can you take a minute to read that to yourself?

A. Yes.

Q. Okay. So if I repeat my -- if I asked my question, again, what will your response be?

A. I'm sorry, sir, I thought in your question you asked me was there no cost, meaning zero cost, and that is the reason I answered the way I did. I do agree that in this one instance in Rate Schedule SBS -- which, Commissioners, is a rate group of three customers. These are customers that are very unique. They don't take full requirement service from Gulf Power. These are large customers who own their own generation, but who nevertheless need backup service from Gulf Power. We have three of those, two of which get the voltage discount. And so that is what we're talking about here.

And I do agree that this one instance is the exception to my comment earlier that, in general, the two methods lead us to very, very similar results. I do agree that here the two cents shown here is substantially different from the current transformer ownership discount offered through the rate schedule.

Q. So would you agree that Gulf is proposing a substantial increase in the transformer discount for Rate Schedule SBS? Let me rephrase it. Would you agree that Gulf is proposing an increase in its transformer discount for Rate Schedule SBS?

A. Yes, sir.

Q. All right. And why is Gulf proposing this increase?

A. Give me one moment, please.

Q. Not a problem. Take your time.

A. Thank you.

Thank you for your indulgence. There's a lot of information here. Because the associated charges in that rate are increasing, are proposed to increase.

Q. Okay. To your knowledge -- moving away from that. To your knowledge, do any other of the four IOUs adjust their existing light fixtures and associated facilities on an annual basis? We're moving to a different subject.

A. I don't know; I'm not sure.

Q. Generally speaking, are there any -- looking at the light fixtures and the associated facilities. Generally speaking, are there significant fluctuations in lighting fixtures and associated facilities or are they relatively fixed for a period of time?

A. I have to ask for a clarification. Do you mean in the number of fixtures we have out in the field, in the cost of those fixtures, in the nature of them?

Q. The cost.

A. It's my understanding that some of the costs -- and I'm distinguishing now, Commissioners, between the company's cost occurred in providing service as distinct from the price we charge for that service. It's my understanding that there is and can be from year-to-year substantial changes in the company's acquisition cost associated with acquiring those lighting facilities.

We are talking here, Commissioners, about unmetered outdoor lighting facilities, fixtures, ballast, bulb, photocell, that stuff at the top of the pole that is outdoor lighting in parking lots and along streets and highways. So my answer is yes, sir, they can change.

Our proposal in that nature, Commissioners, our proposal is currently we have a template which the Commission provided Gulf Power ten years ago in our last rate case, so that every time the company adds a new fixture to our lighting menu, we didn't have to come back over here with that table of attorneys and incur -- on behalf of our customers incur the transaction cost associated with adding one or two new types of lighting fixtures to our overall menu.

Now, while we have been able to do that for the last ten years, to use a methodology or a template that the Commission approved to add new fixtures over the last ten years, it has not been our understanding that we could use that template or methodology to reprice existing fixtures. Our request in this case is to, on an annual basis, review our acquisition cost, the cost associated with acquiring that hardware that I described earlier from the vendors, review our acquisition cost associated with our lighting fixtures, and using the Commission's approved template, lighting pricing methodology, I call it the template, using that template that we could reprice existing fixtures annually.

Q. Not to cut you off, I'm sorry, and I think you gave me a great segue into talking about the costs that Gulf has and what it is proposing to change.

So, Mr. Chairman, what I propose -- what I just identified to you was a part of your exhibit, what

I just handed out to you. It is called Form 4, correct?

A. Correct.

Q. What is Form 4, sir, briefly, if you can?

A. Form 4 is a part of our retail tariff. It is that template, that lighting pricing methodology for pricing lighting fixtures and associated facilities.

Q. Currently on Form 4 is a formula-based template that allows Gulf to price and offer new lighting fixtures and associated facilities, correct?

A. Yes.

Q. And as it stands today, Form 4 does not allow Gulf to reprice existing fixtures and associated facilities annually, correct?

A. Yes, that has been our understanding.

Q. And as an understanding in terms of the filing, Gulf is seeking approval to extend the use of Form 4 to allow it to reprice existing lighting fixtures or associated facilities, correct?

A. Yes, sir, so that our customers won't incur the transaction cost associated with coming over here to do that.

Q. And if as a result of the annual review there is a change of 10 percent or more in either direction in any of the base rate charges, Gulf could automatically reprice the existing fixtures and associated facilities, correct?

A. Yes.

Q. When will this review take place?

A. We haven't determined the exact time of year, but I imagine it would be in the Spring, April or May. We will reset rates and charges, I presume in March of this year, or somewhere around March of this year, and so we certainly wouldn't need to do it for a year after that. That's why I would say we would probably do it for the first time around April or May of 2013, and year thereafter about the same time of year.

Q. And how will customers be notified of the changes in rates?

A. We haven't settled on that yet, the exact method for notifying. We have two or three means at our disposal. We could do it via bill insert. We already notify our customers either annually or twice a year, because I'm not sure which it is, of the availability of rates or other rates that may be available to them. So we already communicate that type of information with our customers. And then, again, we will communicate with our customers at the end of this rate case as to any changes to the rates associated with that. So which of those methodologies we are going to use, we haven't landed on it yet, because we frankly haven't needed to incur the cost associated with landing until we know we can do it. We have a year.

Q. All right. And what effect will this repricing have on the customers who already entered into a long-term contract for lighting fixtures and associated facilities?

A. The price of the lights will change, just as the price of all of our lighting fixtures, I presume, will change in about two to three months.

Q. And since the customers are already entered under this contract, will there be an opt-out provision of the contract?

A. No, sir.

Q. Mr. Thompson, is there a termination charge imposed for customers who choose to opt out of their lighting agreement since there is no opt-out provision due to the price change?

A. I wouldn't characterize it as a termination charge. What we do is a deal is a deal and we would ask the customer to fulfill the term of the contract. And if they didn't, we would charge them for the base charges associated with those lights, except for the energy portion of the overall lighting charge.

The lighting charge, Commissioners, consists of three parts. We charge them for the fixture, we charge them for maintenance of the fixture or the hardware, we charge them for the actual energy, the kilowatt hours they burn or they consume to illuminate the fixture. That third part, we wouldn't charge them for, because they would have walked away from the light. But the first two we would charge them the base rate component of the first two for the duration of the contract. I wouldn't characterize --

Q. I'm sorry to interrupt. I think you said that the customers will be charged under the duration of the contract, correct, not under the new rates?

A. They would be charged the applicable rates for the duration of the contract.

Q. The new rates?

A. Yes, the new rates. Yes.

MR. YOUNG: No further questions.

CHAIRMAN GRAHAM: Commission?

Mr. Thompson, I want to congratulate you on your choice of undergrad school.

THE WITNESS: Thank you, Mr. Chairman.

When my attorney asked me to state my name for the record, you can only imagine what I was tempted to say.

(Laughter.)

CHAIRMAN GRAHAM: Redirect.

MR. GRIFFIN: No redirect.

CHAIRMAN GRAHAM: Exhibits.

MR. GRIFFIN: We would move Exhibit 25, 200, and 201.

CHAIRMAN GRAHAM: Move 25, move 200, and Number 201 into the record.

(Exhibit Numbers 25, 200, and 201 admitted into the record.)

MR. SAYLER: Mr. Chairman, what was Exhibit 200? I missed that earlier. Was that related to O'Sheasy or Thompson?

CHAIRMAN GRAHAM: 200 was -- it was the correction to his Direct Testimony, to his schedules. It was Exhibit JIT-2.

MR. SAYLER: Okay.

CHAIRMAN GRAHAM: That was left off.

MR. SAYLER: Okay. I've got it.

MR. GRIFFIN: JIT-2, Mr. Chairman, was actually his original JIT-2 exhibit, which had been omitted from Staff's Comprehensive Exhibit List, and then the two corrections were admitted as Composite 201, I believe.

CHAIRMAN GRAHAM: That's correct. 201 was the correction, and 200 was the omission from staff.

MR. YOUNG: Yes, sir.

CHAIRMAN GRAHAM: Mr. Thompson, thank you very much for your testimony.

Next witness.

MR. STONE: Mr. Chairman, we have concluded our direct case. The next witness will be an intervenor witness. We have been in discussion with representatives of FIPUG, and we are trying to develop a package of stipulations on either eight or nine issues, and we would welcome an opportunity to discuss the package with the parties and staff before we resume the presentation of evidence, if that would be acceptable to the Chair.

CHAIRMAN GRAHAM: A question I have, we are still holding for staff on the exhibits for Mr. O'Sheasy. Do we have those exhibits?

MR. YOUNG: Not at this time, sir.

CHAIRMAN GRAHAM: Is that part of the conversation you plan on having with the intervenors?

MR. STONE: Well, to be clear, our requested conversation would include staff, and I honestly don't know the status of what impact it would have on Mr. O'Sheasy's exhibits, but it does relate to his issues.

CHAIRMAN GRAHAM: The reason why I asked that question is because I can recess for the day, but that just means Mr. O'Sheasy has got to come back tomorrow if there is not some resolution to that.

MR. STONE: We can accommodate that.

CHAIRMAN GRAHAM: Okay. That being said, then --

MR. MOYLE: Thank you. I appreciate the accommodation. I think hopefully can we can make some headway and maybe shorten things.

CHAIRMAN GRAHAM: Just to let you guys know, let everybody know, we have, according to this schedule, 22 witnesses left and roughly three days we would like to get it done in. So starting tomorrow you may see me move things along a little more expeditiously. I would like for you to get to the questions quicker. If you have difficulty getting the answers to the questions, you can go back and lay the foundation. But I don't think it's necessary, for example, to ask the comptroller three or four times if she's the comptroller. I mean, we just need to get to the question.

If there's nothing else --

MS. BANKS: Mr. Chairman, if the parties would just wait for a little while so we can discuss a meeting time, it would be great.

CHAIRMAN GRAHAM: Yes. I'm just going to recess until tomorrow morning at 9:30, which means the four of us can move off, and you guys can feel free to stay here as long as you want. Our Executive Director is in the back and says the air will stay on until 8:00. So you can decide how long you want to stay.

Is there anything else? Seeing none, travel safe and I hope to see y'all tomorrow morning at 9:30.

(The hearing adjourned at 7:10 p.m.)

(Transcript continues in sequence with Volume 8.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 16th day of December, 2011.

Jane Faurot

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