FILED MAR 22, 2017
DOCUMENT NO. 03762-17
FPSC - COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160186-EI

PETITION FOR RATE INCREASE BY GULF POWER COMPANY.
_______________________________/

DOCKET NO. 160170-EI

PETITION FOR APPROVAL OF 2016 DEPRECIATION AND DISMANTLEMENT STUDIES, APPROVAL OF PROPOSED DEPRECIATION RATES AND ANNUAL DISMANTLEMENT ACCRUALS AND PLANT SMITH UNITS 1 AND 2 REGULATORY ASSET AMORTIZATION, BY GULF POWER COMPANY.
_______________________________/

VOLUME 2

(Pages 254 through 505)

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN JULIE I. BROWN
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER DONALD J. POLMANN

DATE: Monday, March 20, 2017

TIME: Commenced at 1:00 p.m.
Concluded at 2:53 p.m.

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

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

No exhibits in this volume

GULF POWER COMPANY

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

Q. Please state your name and business address.

A. My name is Xia Liu. My business address is One Energy Place, Pensacola, FL 32520.

Q. By whom are you employed?

A. I am employed by Gulf Power Company (Gulf or the Company) as Vice President and Chief Financial Officer (CFO).

Q. What are your responsibilities as Vice President and CFO?

A. I oversee all financial matters and decisions for Gulf and am responsible for maintaining the overall financial integrity of the Company. My areas of responsibility include the Accounting, Corporate Secretary, Treasury, Regulatory, Corporate Planning, Forecasting and Pricing departments. I am responsible for financial planning and for maintaining the Company's financial and accounting records. I also maintain strong relationships with the financial community, including the rating agencies, and serve as a member of Gulf's Management Council. Additionally, I represent Gulf Power as a member of the Southern Company Accounting, Finance and Treasury (AFT) Management Council, which is comprised of CFOs from Southern Company and all sister operating companies.

Q. Please state your prior work experience and responsibilities.

A. I have been employed with the Southern Company system since 1998. I have lived in three of the four states where the Southern electric system of which Gulf is a part serves retail customers. In my career, I have held positions working with Southern Company, Southern Company Services (SCS), Alabama Power and now Gulf Power.

Prior to moving to Gulf in 2015, I served as senior vice president of finance of SCS and treasurer of Southern Company. In that role, I had responsibilities overseeing the overall finance and treasury functions of Southern Company including strategic development, mergers and acquisitions, financial analysis, corporate planning and budgeting, treasury, enterprise risk management, insurance management, and pension and trust finance management. I oversaw rating agency, fixed income investor, investment banking and commercial banking relations and had regular meetings with all these financial institutions both domestically and internationally.

Prior to 2010, I served in various roles at various business units. I was the director of financial planning and assistant treasurer for Alabama Power Company, where I testified on behalf of Alabama Power before the Alabama Public Service Commission. I was the environmental and compliance manager for fuel services at SCS from 2005 to 2007, where I had responsibilities developing fuel procurement strategies including coal, natural gas, environmental commodities and emission allowances.

Q. What is your educational background?

A. I graduated from Renmin University of China, one of the nation’s top universities located in the capital city of Beijing, with bachelor’s and master’s degrees in finance. I also hold an MBA from Emory University’s Goizueta Business School in Atlanta, Georgia. Additionally, I spent two years in the Ph.D. in Economics program at Emory University and completed preliminary Ph.D. course work.

Q. Do you hold any certifications?

A. Yes. I have been a Chartered Financial Analyst (CFA) since 2001. The CFA designation is a professional credential offered internationally by the American-based CFA Institute to investment and financial professionals. It measures the competence and integrity of financial analysts. Candidates are required to pass three levels of exams covering areas such as accounting, corporate finance, economics, ethics, money management and security analysis.

Q. What is the purpose of your testimony?

A. My testimony begins with an overview of Gulf’s need for rate relief. I then explain the Company’s decision to use a projected 2017 test year for ratemaking purposes and provide a summary description of Gulf’s financial performance since our last base rate increase. I discuss the rededication of a portion of Plant Scherer Unit 3 and related common facilities (collectively, Scherer 3) to serve our retail customers and explain that it is critical for the Florida Public Service Commission (Commission) to recognize and approve the reintegration of Scherer 3 into the retail jurisdiction and to authorize base rate recovery of the associated non-clause costs. Next, I identify the drivers behind the request for rate relief. I then discuss the importance of the rate relief Gulf is requesting to Gulf's financial integrity and credit quality. I also discuss Gulf's capital structure and cost of capital. Finally, I explain why it is not appropriate to make a parent debt adjustment to Gulf's income tax expense in determining our revenue requirement.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit XL-1, consisting of Schedules 1 through 8. These schedules were prepared under my control and supervision, and the information contained therein is true and correct to the best of my knowledge and belief.

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

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

I. NEED FOR RATE RELIEF

Q. Why is Gulf seeking rate relief at this time?

A. Gulf is a capital-intensive, regulated electric utility which has an obligation to provide reliable service to its customers at a reasonable cost. We take this obligation seriously and put our customers at the center of everything we do. We also take seriously the need to provide our investors a fair return on their investment in Gulf, commensurate with its risk, so that we can attract the capital needed to support the continued investment required to serve customers. Gulf can continue providing the quality service that our customers expect and deserve only if we remain financially strong—and that requires maintaining the appropriate balance of the interests of all our stakeholders.

Gulf needs rate relief at this time because our current rates will not produce sufficient revenues for us to continue adequately serving our customers while maintaining the Company's financial integrity. We need additional revenues to cover our expenses, to enable us to fund the significant capital expenditures that are required to continue to provide reliable electric service, and to provide a fair return on the assets serving our customers.

Q. What is the amount of base rate relief that Gulf is requesting in this case?

A. Gulf is requesting an annual increase of $106.8 million in base revenues. This is the amount necessary for Gulf to continue to provide quality service to its customers and provide its investors the opportunity to earn a fair rate of return of 11.0 percent on the Company's common equity, as supported by the testimony of Gulf Witness Vander Weide.

II. TEST YEAR

Q. What test year has Gulf used to calculate its proposed rate increase?

A. Gulf has chosen a 2017 projected test year. The projections for 2017 are based on Gulf's 2016 budget process. As described in more detail by Gulf Witness Mason, Gulf's annual budget process produces a budget for the current year and a budget forecast for the four subsequent years. The 2016 "prior year" shown in the MFRs is also the result of the 2016 budget process, while the 2015 "historical year" reflects actual results for that year.

Q. Please explain why 2017 was chosen as the test period.

A. The 2017 test year is the appropriate representation of Gulf's expected future operations. The 2017 test year properly matches Gulf's projected revenues with the projected costs and investment required to provide service to customers during the period following the effective date of the new base rates in this case. The use of a projected test year that includes information related to rate base, net operating income, and capital structure for the time new rates will be in effect benefits all stakeholders by helping to reduce the impact of regulatory lag. Gulf's use of a projected test year is also consistent with the Commission's long-standing practice of approving projected test years.

III. FINANCIAL PERFORMANCE

Q. When was Gulf's last rate case?

A. Gulf's last rate case was filed in July 2013 and was based on a 2014 test year. This case was resolved via a settlement agreement among all parties to the proceeding. The Stipulation and Settlement Agreement (2013 Settlement Agreement or Settlement) was unanimously approved by the Commission in Order No. PSC-13-0670-S-EI issued December 19, 2013 in Docket No. 130140-EI.

Q. Please provide a general overview of the major elements of the Settlement.

A. The Settlement covers a term of 42 months beginning with the first billing cycle of January 2014 and ending on the last billing cycle of June 2017. Gulf's base revenue was increased by $35 million in January 2014 and by an additional $20 million in 2015, for a total increase of $55 million. Gulf's authorized return on equity (ROE) was maintained at 10.25 percent, which is the same as the midpoint ROE set by the Commission in Gulf's previous rate case. The Settlement declared certain transmission projects with in-service dates ranging from 2013 to 2018 to be prudent for cost recovery purposes. Gulf was permitted to accrue a special Allowance for Funds Used During Construction (AFUDC)-like charge for these projects past their in-service dates until January 1, 2017. At that time the transmission investment will be included in rate base for ratemaking purposes. The Settlement also allowed Gulf to credit up to $62.5 million to depreciation expense over the 42-month term of the agreement.

Q. What has been the impact of the Settlement on Gulf's financial performance?

A. As noted in the Commission's order approving the Settlement, allowing Gulf to accrue the AFUDC-like treatment for the identified transmission projects and to credit depreciation expense was intended to provide a means for Gulf to adjust and stabilize its earnings throughout the 42-month Settlement term and neither over- or under-earn its allowed ROE of 10.25 percent with a range of plus or minus 100 basis points. The availability of the tools provided by the Settlement has helped the Company to earn within its authorized range for much of the period covered by the Settlement.

Q. Does Gulf need additional rate relief beginning July 1, 2017, when the 2013 Settlement Agreement expires?

A. Yes. All other things being equal, the termination on January 1, 2017 of Gulf's ability to accrue AFUDC-like charges on the transmission projects and the depletion prior to the end of the Settlement period of the allowable depreciation credits would trigger the need for rate relief to replace these non-cash earnings with base rate revenues to cover our expenses and provide a fair return on our investment.

However, all other things are not equal. For example, the sales growth that Gulf projected in our 2012 test year rate case has failed to materialize, while at the same time we continue to grow rate base through capital investment in order to continue to provide reliable service to our customers. Additionally, with the expiration of wholesale contracts covering approximately 76 percent of Gulf's investment in Scherer Unit 3, the non-clause portion of the related revenue requirement must be included in base rates.

Q. What is Gulf's projected ROE without rate relief?

A. Based on our current projection, the depreciation credits allowed under the 2013 Settlement Agreement will be fully utilized by the end of the first quarter of 2017. As shown on Schedule 2 of my exhibit, Gulf's ROE will fall to approximately 7.30 percent, well below the bottom of its authorized range, before rates from this case can be put into effect on July 1, 2017. Without rate relief, Gulf's return would continue to drop.

IV. SCHERER 3

Q. In your view as Chief Financial Officer of Gulf, is it critical that the Commission allow recovery through retail rates of the portion of Scherer 3 that has been rededicated to serving retail customers?

A. Yes. One of the primary differences between Gulf and many other businesses is that Gulf has the obligation to provide reliable service to our native load customers and to deploy capital well in advance to ensure we meet the long-term needs of these customers. Our business is capital intensive, our capital assets are long lived, and generating units in particular have a long planning and construction lead time. Thus, we must constantly make long-term investment decisions based on the best information available to us at the time in order to meet the current and future needs of the customers we are obligated to serve.

As a regulated utility, once a prudent investment such as Scherer 3 has been made to serve our customers, we must be afforded the opportunity to earn a fair return on that investment. Under the regulatory compact that Gulf Witness Deason describes in more detail, utilities need the assurance that they will be allowed to recover the cost of prudent investments over the life of the asset, regardless of future changes in circumstances. It is important to ensure fair regulatory treatment of utilities' past long-term investments in order to preserve the ability to make future long-term investments. Without the assurance that prudent costs will be recovered, utilities would find it difficult to continue to consistently make the long-term investments that are required by their obligation to serve.

Q. When and why did Gulf make its investment in Scherer 3?

A. As described by Gulf Witnesses Burleson and Deason, Gulf acquired its interest in Scherer 3 in the mid-1980s as a cost-effective alternative to a generating unit then being planned for construction at Gulf's Caryville site for the purpose of serving Gulf's native load customers. At that time, Gulf had the opportunity to enter into interim long-term wholesale contracts in order to provide a bridge that would temporarily relieve Gulf's native load customers of the obligation to support the Scherer 3 revenue requirements. As discussed by Mr. Deason, the Commission encouraged Gulf to proceed with the purchase of an interest in Scherer 3 and to enter into the interim long-term wholesale contracts for the ultimate benefit of Gulf's retail customers.

Q. Did Gulf in fact make long-term off-system sales to temporarily relieve native load customers of the obligation to support Scherer 3?

A. Yes. Gulf entered into Unit Power Sales (UPS) contracts that initially committed most of the unit's capacity to the wholesale market through 1995. Subsequently, Gulf entered into other wholesale contracts that ultimately continued to commit the Scherer 3 capacity to the wholesale market through December 31, 2015 (110 MW), May 31, 2016 (50 MW) and December 31, 2019 (50 MW).

Q. What is the status of Scherer 3 today?

A. For the first time since Scherer 3 began commercial operation, a substantial majority (76 percent) of Scherer 3 is not committed to long-term wholesale contracts. The first of the last vintage of three wholesale contracts, covering 52 percent of Gulf's interest in Scherer 3, expired on December 31, 2015. The second contract of that vintage, covering 24 percent of Gulf's interest in Scherer 3 expired on May 31, 2016. The final of the three contracts will expire at the end of December 2019. As these wholesale contracts expire, Gulf's Scherer 3 investment is being rededicated to serving the native load customers for whom it was originally planned, acquired and ultimately built.

Q. Please explain the impact on Gulf of the expiration of the long-term wholesale contracts.

A. The costs of the rededicated portion of Scherer 3 are not currently being recovered through any rates despite the fact that it is now serving Gulf's native load customers.

Q. Does your current request in this case include all costs of the portion of Scherer 3 dedicated to serving retail customers?

A. No. Gulf has also filed a petition and testimony in the Environmental Cost Recovery Clause (ECRC) docket (Docket No. 160007-EI) requesting that the portion of Scherer 3 costs eligible for recovery through the ECRC be authorized for recovery in that docket. The ECRC portion of the Scherer 3 revenue requirement currently represents more than 40 percent of the total revenue requirement for the portion of the unit that serves retail customers. That request is still pending as of the date this testimony is being filed.

Q. What action is Gulf currently asking the Commission to take with respect to Scherer 3 in this docket?

A. We are asking the Commission to approve the rededication of Scherer 3 as a retail asset by allowing Gulf to recover in base rates the jurisdictional portion of the Scherer 3 revenue requirement that is not eligible for recovery through the ECRC. Specifically, we are asking the Commission to 1) reconfirm Gulf's ownership of Scherer 3 as a resource intended for and serving our native load customers, and 2) allow the jurisdictional portion of

Scherer 3 non-clause costs to be recovered in base rates as reflected in the testimony and exhibits of Gulf Witness Ritenour.

These actions will make it clear that the costs associated with the portion of the investment in Scherer 3 not committed to long-term off-system sales should be recovered from the retail customers being served by that investment. The Commission contemplated this result when it encouraged Gulf to market the Scherer capacity off-system as a temporary bridge of responsibility for supporting the revenue requirements associated with this investment. The Scherer 3 investment that was prudently made to serve retail customers will now be supported by those customers, although at its depreciated net book value. This treatment is consistent with the regulatory compact discussed by Mr. Deason.

Q. Why is this treatment critical to Gulf's customers and investors?

A. As I stated earlier, Gulf must continually evaluate and make long-term investments in order to fulfill its obligation to serve. It is critical to both Gulf and our customers that the utility be assured that it can recover through rates the cost of the prudent investments it undertakes to meet that obligation. That is the essence of the regulatory compact described by Mr. Deason. If Gulf were denied the ability to recover its investment in Scherer 3 from the customers for whom it was planned, acquired and ultimately built, that decision would make it difficult for Gulf to continue to consistently take a long-term view when making future investment decisions. Such a decision could also harm the current perception of a constructive regulatory environment in Florida, which would negatively impact Gulf and other Florida utilities.

V. RATE CASE DRIVERS

Q. What are the factors causing Gulf's need for rate relief?

A. At a high level, our need for rate relief is driven by the fact that Gulf's revenue growth since 2012 has not kept pace with our increased level of investment and expenses needed to serve our customers, despite the additional base rate relief we received under the 2013 Settlement Agreement beginning in 2014. In fact, as shown on Schedule 3 of Exhibit XL-1, Gulf's weather-normalized annual GWh sales have never reached the level that we originally projected to achieve in 2012, and sales are not currently projected to reach that level in 2017. This means that Gulf's current rates will not produce sufficient revenues to meet our need to continue to spend and invest to serve our customers.

Q. Have you performed an analysis to determine the specific drivers behind Gulf's need for rate relief?

A. Yes. Because our 2014 test year rate case was resolved by settlement, Gulf's 2012 test year case (Docket No. 110138-EI) is the last time that the Commission specifically reviewed and approved all the elements that make up our revenue requirement. In order to determine the major rate case drivers, I started with Gulf's revenues, expenses and investments as approved by the Commission in the 2012 test year rate case. I then compared the 2012 Commission-approved figures to our 2017 test year request in order to identify the changes that contribute to our need for a $106.8 million base rate increase.

Q. What did this analysis show?

A. Schedule 4 of Exhibit XL-1 is a waterfall chart that presents the results of the analysis. It shows that there are five primary groups of drivers that increase Gulf's overall revenue requirement in 2017 compared to 2012:

- $19.4 million base rate revenue requirement associated with the rededication of Scherer 3 to serve native load customers;
- $91.5 million revenue requirement associated with increases in rate base due primarily to infrastructure initiatives;
- $34.7 million from growth in non-clause O&M expenses;
- $17.7 million of sales deficiency related to the lagging economy and reduced use per customer; and
- $18.8 million from other changes in the cost of service, primarily driven by an increase in depreciation expense.

These upward pressures are offset by four primary items that reduce, or contribute to meeting, the increased revenue requirement:

- $2.0 million due to reduction in Gulf's weighted average cost of capital;
- $59.0 million of base rate increases since 2012;
- $9.3 million of increases in other operating revenues; and
- $5.0 million reduction in the annual dismantlement accrual.

Drivers of Rate Request

Q. Please explain the increase in revenue requirement associated with Scherer 3.

A. As I discussed above, 76 percent of Gulf's ownership in Scherer Unit 3 is no longer covered by wholesale contracts and has been rededicated to serve native load customers. The revenue requirement associated with the non-clause retail portion of Scherer Unit 3 is $19.4 million in the 2017 test period. This amount includes return on investment, depreciation, O&M expense and taxes.

Q. Please explain the increase in revenue requirement due to other rate base changes.

A. This $91.5 million is the revenue requirement associated with two other categories of increased non-clause investment.

First, it includes Gulf's investment in a group of specific transmission projects that all parties to the 2013 Settlement Agreement agreed were prudent for cost recovery purposes. The Settlement provided that the investment in these projects would be added to rate base no later than January 1, 2017. These investments are addressed in the testimony of Gulf Witness Smith. The revenue requirement for these projects is $28.7 million. This revenue requirement includes the amortization over four years of the transmission-related AFUDC-like regulatory asset created pursuant to the Settlement and discussed in the testimony of Ms. Ritenour.

Second, there is a $62.8 million revenue requirement for net rate base increases since 2012 for items other than the specific transmission projects and Scherer 3. This category primarily consists of investments in Gulf's power grid systems and Gulf's generating fleet that is used and useful in providing service to our customers. As discussed by Mr. Smith, in addition to the specific transmission projects discussed above, Gulf has continued to invest in its transmission infrastructure since Gulf's 2012 test year rate case. Gulf has also made additional investment in our distribution assets related to storm hardening, grid modernization, new business and other distribution infrastructure improvements. Furthermore, Gulf Witness Burroughs discusses the major non-ECRC production additions that contribute to an increase in Gulf's production investment. This category also reflects changes in working capital and other miscellaneous rate base items as supported by Ms. Ritenour.

Q. Please explain the increase related to growth in non-clause O&M expense.

A. Excluding amounts related to Scherer 3, Gulf's non-clause O&M expense has increased by $34.7 million since 2012 due to a variety of factors, including customer growth and inflation. Only $1.5 million of this amount reflects growth over and above the Commission's O&M benchmark. The benchmark overages in specific functional areas are discussed by other witnesses. As they explain, the requested O&M expenses are necessary to continue to provide our customers with the reliable service that they expect and deserve. It is important to note that the benchmark variance includes the effect of Gulf's requested $5.4 million increase in the annual accrual to the property damage reserve as explained by Gulf Witness Hodnett. Without this $5.4 million request, our O&M increase would be below the Commission's benchmark.

Q. Please explain the deficiency in 2017 projected sales revenues compared to the level originally projected for 2012.

A. The Commission-approved rates in Gulf's 2012 test year rate case were designed to meet Gulf's revenue requirement during the 2012 projected test year, based on Gulf's forecast of 2012 GWh sales. Due to a combination of slower than forecasted customer growth and a decline in usage per customer, Gulf's GWh sales have never reached the level originally projected for 2012, as shown on Schedule 3 of my exhibit. Instead, based on the 2016 forecast used for the test year projections, GWh sales for 2017 are forecast to be 6.3 percent below the originally projected level for 2012. At current rates, this produces test year revenues that are $17.7 million below the amount the rates approved in 2012 were designed to produce. This shortfall contributes to the 2017 revenue deficiency.

Q. Please explain the other changes in cost of service.

A. The other changes in cost of service consist of two items. The first is a $12.1 million increase in depreciation expense that results from applying the new depreciation rates included in the 2016 Depreciation Study filed on July 14, 2016, and corrected on September 20, 2016, in Docket No. 160170-EI to Gulf's 2017 test year rate base, rather than applying Gulf's currently approved rates to the same rate base. Gulf Witnesses Watson and Hodnett discuss Gulf's depreciation expense request in more detail.

The remaining $6.7 million is primarily the result of property tax and payroll tax increases.

Offsets to Rate Drivers

Q. Please explain the offset due to a reduction in Gulf's weighted average cost of capital.

A. Gulf's overall jurisdictional weighted average cost of capital (WACC) has declined from 6.39 percent as approved in the 2012 rate case order to a requested level of 6.04 percent for the 2017 test year. This change reduces Gulf's revenue requirement by $2.0 million. This reduction is the result of a combination of factors, including changes in the cost of debt and equity, and changes in the proportion of the various sources of capital in Gulf's overall jurisdictional capital structure.

Q. Please explain the offset provided by the $59.0 million in previously approved rate increases.

A. Up to this point, I have calculated a revenue requirement shortfall by comparing the Commission-approved investment and expenses from the 2012 test year to Gulf's projections for 2017. Since 2012, Gulf's base rates have changed on three occasions, namely: (1) a $4 million step increase effective January 1, 2013 pursuant to the 2012 test year rate case order; (2) a $35 million increase effective January 1, 2014 pursuant to the 2013

Settlement Agreement; and (3) a $20 million increase effective January 1, 2015 pursuant to that same Settlement. These rate increases offset a portion of the calculated revenue requirement shortfall.

Q. Please explain the $9.3 million offset provided by other operating revenues.

A. Since 2012, Gulf's other operating revenues have increased by $9.3 million. Like the base rate increases, these other operating revenues serve to reduce Gulf's revenue requirement shortfall.

Q, Please explain the offset provided by reduction in the annual dismantlement accrual.

A. Gulf has submitted an updated dismantlement study discussed in the testimony of Ms. Hodnett. This item represents the reduction in Gulf's annual dismantlement accrual compared to the amount included in the 2012 test year. As I previously discussed, the settlement agreement in Gulf's last rate case allowed Gulf to record up to $62.5 million in credits to depreciation expense as a method to adjust and stabilize its earnings. These credits were recorded to a regulatory asset account referred to as Other Cost of Removal. The Settlement provided that this regulatory asset would be considered and accounted for in conjunction with the accumulated cost of removal and the dismantlement reserve balances the next time the Commission establishes depreciation rates and dismantlement accruals. As described in the testimony of Ms. Hodnett, Gulf proposes to apply this regulatory asset to reduce the projected dismantlement reserve surplus shown in Gulf's 2016 Dismantlement Study filed on July 14, 2016 in Docket

No. 160170-EI. As discussed by Ms. Hodnett, Gulf proposes to reduce the annual dismantlement accrual in base rates to zero. This is a reduction of approximately $5.0 million from the current accrual level, and reduces the rate relief that Gulf would otherwise require.

Q. As a result of all these factors, what is the amount of Gulf's rate request?
A. As I stated earlier, Gulf is requesting an annual increase of $106.8 million in base revenues in order to cover our expenses and provide the opportunity for our investors to earn a fair rate of return. That opportunity is essential to attracting the capital that is required, not just for our current capital expenditure program, but to sustain Gulf's ability to continue to provide the service that our customers expect and deserve in the years to come at fair, just and reasonable rates.

VI. FINANCIAL INTEGRITY

Q. What does financial integrity mean to Gulf Power?
A. Financial integrity means maintaining a strong financial position that is sufficient to meet our current financial obligations and to sustain the confidence of investors in order to attract capital—continuously and on reasonable terms—so that we can consistently provide reliable service to our customers at a reasonable cost.

Q. Why is financial integrity important?

A. Financial integrity is critical to Gulf because of our obligation to serve our customers. As a capital-intensive regulated electric utility, Gulf must meet its obligation to serve at all times. We must continually make investments that are required to reliably generate and deliver electricity, even during challenging economic conditions or strained financial markets. Meeting that obligation requires on-going capital investments to both maintain our electric system and expand to serve increasing demand. We must therefore at all times maintain access on reasonable terms to all capital markets.

Additionally, continuous access to short-term debt markets, including commercial paper, is critical to provide the liquidity Gulf requires in managing its day-to-day operational cash needs. Those needs are highly variable in response to things such as changes in fuel prices and variations in sales. The short-term debt markets provide a cost-effective source of financing for these purposes.

Q. Please describe Gulf's financial position.

A. As a result of the 2013 Settlement Agreement, Gulf has maintained a satisfactory level of financial strength since 2014. However, the Settlement contained mechanisms that increased Gulf's earnings without providing the corresponding cash flow. This negatively affects both the quality of Gulf's earnings and its key credit metrics. Upon expiration of the agreement, these non-cash earnings need to be replaced by an increase in base rate revenues. In addition, it is essential to maintaining Gulf's financial strength that the Commission allows recovery through retail rates of the portion of Scherer 3 that has been rededicated to retail service. Without rate relief, the revenues produced by Gulf's current rates will be insufficient to cover our expenses and at the same time provide an adequate return to our investors. This revenue level is clearly deficient and will create a challenge in supporting equity investment in the future.

From the viewpoint of our debt holders, Gulf's current credit ratings have been sufficient to allow us to maintain access to debt markets and to finance that debt at favorable rates. However, as I will discuss later, with insufficient cash revenues to cover its expenses and provide a fair return to investors, Gulf is concerned about the effect of declining credit metrics and credit ratings.

Q. Does Gulf face business risks that could affect its ability to maintain its financial strength and access to capital?

A. Yes. As discussed in broad terms by Dr. Vander Weide, Gulf faces a number of business risks that are common to electric utilities throughout the country. I will briefly discuss examples of a few specific risks, including: (1) risks associated with Gulf's regulatory environment and ability to recover costs; (2) risks related to sales uncertainty driven by weather, economic conditions and Gulf's customer mix; (3) risks associated with hurricane and tropical storm exposure; and (4) risks caused by evolution of the electric utility industry.

Q. Please explain risks related to Gulf's regulatory environment and ability to recover costs.

A. Investors and rating agencies all focus on the regulatory environment and ability to recover costs in a timely manner when they make investment and rating decisions. For example, Regulatory Research Associates (RRA) evaluates the regulatory climates of the jurisdictions on an ongoing basis. RRA's August 2016 Florida Regulatory Review publication states, "RRA continues to view Florida regulation as constructive from an investor perspective" and rates Florida regulation "above average." As I will discuss in detail later in the testimony, all the rating agencies comment on Florida's regulatory climate and Gulf's ability to recover costs.

Although Florida is currently considered a supportive regulatory environment, any change or perceived change to the environment could greatly impact Gulf's business risk. Additionally, the timeliness of cost recovery poses a significant risk to Gulf. Given the time necessary to prepare, file and process a rate case, Gulf is exposed to significant regulatory lag.

Q. Please describe Gulf's risks related to sales uncertainty.

A. Like other utilities, Gulf is exposed to economic uncertainty and sales risk. In Gulf's case this risk has been evidenced for an extended period of time by slow growth in sales and revenues, driven primarily by declines in use per customer. As a result, sales and revenues have not reached forecasted levels. This has posed a particular challenge to Gulf, as a small utility with a large concentration of its revenue in the residential and commercial sectors. Schedule 5 of my exhibit shows that Gulf's use per customer in both sectors has steadily declined over the past decade. As discussed by Gulf Witness Park, the factors leading to this decline in residential and commercial use per customer include the slow recovery of the economy and continuing energy efficiency measures adopted by our customers.

This sales risk is underscored by the fact, discussed by Mr. Park, that Gulf's most recent forecast of 2017 base revenues shows a $5.7 million shortfall compared to the forecast on which our test year calculations have been based, which has an impact of over 30 basis points on our retail return on equity.

Q. Please explain risks related to hurricane and tropical storm exposure.

A. Gulf faces significant exposure to tropical storms, more than most other utilities. Because of Gulf's size and location, its service area can be and has been impacted significantly by a single storm. In the aftermath of Hurricane Ivan in 2004, over 90 percent of Gulf's customers lost power. Due to the destruction of homes and other property, nine months passed before Gulf's customer counts returned to pre-Ivan levels. As discussed by Ms. Hodnett, we are proposing to increase our property damage accrual in order to build the balance in the funded reserve and thereby mitigate the financial impacts of storm restoration. However, the potential for lost sales due to hurricanes and tropical storms remains a significant risk to Gulf.

Q. Please explain risks associated with the evolution of the electric utility industry.

A. As the electric utility industry continues to evolve, new risk factors come into play. For example, cyber security threats are requiring utilities to increase their infrastructure investment. Mr. Smith discusses these impacts in his testimony. Additionally, technology is creating new customer expectations that the traditional regulated utility business model did not envision. To meet customers' evolving demand for enhanced services and to respond to an expanded range of customer service expectations, utilities need to make new investment in their customer service infrastructure as discussed by Gulf Witness Terry. These changed expectations will, at first, increase both costs and risks as utilities adapt to the new environment. These developments in the electric utility industry pose new challenges to which Gulf must respond.

Q. What is the impact on Gulf of these types of business risk?

A. All of these risk factors pose concerns about sustaining our financial integrity. Given continued sales uncertainty, Gulf's need for liquidity for operations, and the continuing need to support sizable capital expenditures, maintaining our financial integrity remains a top priority for Gulf.

VII. CREDIT QUALITY

Q. What credit ratings does Gulf target?

A. Gulf targets ratings in the middle of the "A" category for its long-term debt for all three of the major credit rating agencies – Moody's Investor Service (Moody's), Standard & Poor's (S&P), and Fitch Ratings (Fitch). Gulf targets comparable ratings for its short-term debt.

Q. What are Gulf's current long-term credit ratings?

A. Gulf currently has an "A2" rating from Moody's, an "A-" rating from S&P, and an "A" rating from Fitch.

Q. What factors are considered in Gulf's credit risk profile?

A. The rating agencies consider both qualitative and quantitative factors in assessing a company's credit risk. For example, Moody's rates electric utilities based on four categories of factors. They assign specific weight to each factor: 40 percent is assigned to financial strength, 25 percent to regulatory framework, 25 percent to ability to recover costs and earn returns, and 10 percent to diversification. Each of these broad areas has two or more sub-factors. Moody's considers all the factors and applies qualitative adjustment in producing its final rating.

Q. How does Gulf rate on these factors?

A. Florida currently has a supportive regulatory environment in the view of the rating agencies in their most recent reports. Moody's said that Gulf's "rating reflects a credit supportive regulatory environment in Florida." S&P said that Gulf operates "under a generally constructive regulatory environment." Fitch said that constructive regulation is "a key credit positive for Gulf Power." These are an improvement over views expressed several years ago and have a positive impact on their overall evaluation of Gulf, which was a major contributing factor to Moody's upgrade in Gulf's credit rating in 2014.

Moody's notes that Gulf ranks in the Baa range on "Sufficiency of Rates and Returns." Moody's also notes that Gulf's cash flow coverage metrics have been weak for its A2 credit rating. For example, Gulf ranks in the Baa range on certain cash flow from operations to debt coverage ratios. S&P views Gulf Power's financial risk profile as being in the "significant" category and expects the core ratios to weaken somewhat over the next few years as capital spending rises. Fitch indicates that Gulf's financial metrics are in line with its current rating category.

Q. Do you have concerns about Gulf's current credit ratings?

A. I do. As noted by the rating agencies, our financial metrics are important to maintain our targeted credit ratings. While the agencies' opinions of the Florida regulatory environment are now positive, Gulf's financial metrics could deteriorate to levels that would adversely impact our ratings. The Company's cash flow coverage metrics, which measure, among other things, the amount of cash flow available to serve our debt, will be pressured due to our continuing capital expenditure program. Without rate relief, those metrics will deteriorate even further and pose greater risk to Gulf's ability to maintain our targeted credit ratings.

As noted earlier, while Gulf is currently at its targeted rating level of A2 with Moody's, they have stated that Gulf's cash flow coverage metrics have been weak for its A2 rating. They have also stated that metrics are an important factor that could lead to either a rating upgrade or downgrade in the future. Absent rate relief, Gulf's metrics would decline from current levels and place this rating in jeopardy.

Q. Do you have any concerns beyond a decline in Gulf's credit metrics?

A. Yes. The metrics are certainly our biggest concern regarding our credit quality today. However, if the outcome of this case is not sufficient to recover our cost of service including fairly compensating investors, not only will our credit metrics suffer more damage, but also the credit rating agencies' assessment of Florida's constructive regulatory environment could be affected. For example, I would be concerned about these impacts if the Commission did not authorize retail recovery for the portion of Scherer 3 that is now serving retail customers.

Q. Why is it necessary to maintain these targeted credit ratings?

A. Maintaining these targeted credit ratings is critical for Gulf and its customers. An electric utility's obligation to serve requires continuous access to capital markets to fund the maintenance of and investment in the assets needed to reliably generate and deliver electricity. The targeted credit ratings help ensure access to long-term debt capital on reasonable terms and conditions. This is especially important now for Gulf, as we remain in the midst of an ongoing capital investment period. Over the period 2016-2020, our total retail capital investment is projected to average approximately $215 million per year.

Q. Are there similar credit concerns related to the short-term debt markets?

A. Yes. Gulf also requires access to short-term debt markets, including the commercial paper market, to meet our liquidity needs. The ability to access the commercial paper markets at any time is crucial to Gulf, since our short-term funding needs are difficult to predict and can vary dramatically with fuel price volatility, seasonal changes in customer demand, the effects of continued economic uncertainty, and the need for ready access to cash to respond to potential storm damage above the amounts in our property damage reserve. Short-term debt is less expensive and offers flexibility in meeting these needs of our customers.

Strong credit ratings are necessary to ensure continuing access to the commercial paper markets. Companies with credit ratings lower than those targeted by Gulf may experience difficulty in securing short-term funding. Some buyers of commercial paper are restricted to buying the commercial paper of only those companies with high quality ratings, potentially adversely affecting the liquidity, or the ability to access cash quickly, of companies with weaker ratings. During the height of the recent financial crisis, some companies with lower credit ratings were unable to access the commercial paper markets. Credit ratings below those targeted by Gulf could restrict access to those short-term debt markets, particularly during times of economic or financial uncertainty.

Q. Would there be any impacts if Gulf suffered a ratings downgrade?

A. There are several potential impacts depending on the severity of the downgrade. First, a downgrade would increase borrowing costs and, under certain economic conditions, a downgrade in short term ratings could limit or preclude Gulf's access to the commercial paper market, all to the detriment of our customers. In addition, Gulf is party to numerous contractual agreements, including power purchase agreements and fuel storage and transportation agreements, which require the parties to post performance security in certain circumstances. Downgrades by one or more agencies can trigger requirements to post security in the form of cash or letters of credit. Depending on the degree of the downgrade, Gulf could incur aggregate security posting obligations between $135 million and $525 million.

Q. Please summarize your views on the importance of maintaining strong credit ratings.

A. Gulf's ability to maintain strong credit ratings has benefitted customers through lower debt costs and has ensured the Company's ability to fulfill its obligation to serve by maintaining access to capital at all times, including through the most difficult economic periods. Maintaining our targeted credit ratings is essential to our ability to continue to provide reliable service at a reasonable cost for our customers.

VIII. CAPITAL STRUCTURE AND COST OF CAPITAL

Q. What capital structure has Gulf maintained in the past?

A. Over the past ten years, Gulf has maintained a corporate capital structure with approximately 47 percent common equity, 5 percent preferred or preference stock, and 48 percent debt for investor sources of capital.

Q. Is this a typical capital structure for electric utilities in Florida?

A. No. Gulf has previously maintained a lower equity ratio than the other electric utilities regulated by the Commission. As shown on Schedule 6 of my exhibit, in the most recent rate decisions that addressed capital structure, the Commission approved equity ratios (taking into account only investor sources of capital) for FPL, Duke, and TECO that range from approximately four to thirteen percentage points higher than Gulf's approved equity ratio. According to the June 2016 surveillance reports, the average equity ratio for these three Florida utilities was 56.7 percent, about ten percentage points higher than Gulf Power's equity ratio.

Q. What are the implications of a company having a lower equity ratio?

A. With a lower equity ratio, a company's financial risk is higher. Equity investors require compensation for this additional risk through a higher return. In addition, all rating agencies look at the equity ratio as a measurement in assigning the credit ratings. The lower the equity ratio, the more pressure a company has on its credit rating and therefore on its borrowing costs.

Q. Does Gulf have a higher authorized return to reflect this increased financial risk?

A. No. Despite its higher financial risk, and requests in prior rate cases for an ROE adjustment to reflect this higher risk, Gulf's authorized return of 10.25 percent is tied for the lowest among the major Florida investor-owned utilities (IOUs). FPL and Duke, with higher equity ratios of 59.1 percent and 50 percent, both have an authorized return of 10.5 percent. TECO has an authorized return of 10.25 percent with a 54 percent equity ratio. Gulf's lower equity ratio and higher financial risk suggest that its authorized ROE should be higher than the authorized ROEs for these other companies, yet its authorized return is tied for the lowest.

Q. What capital structure is Gulf using in this case?

A. Gulf is using a capital structure of 53 percent common equity, 42 percent debt, and 5 percent preference stock for its investor-supplied sources of capital. Under this capital structure, coupled with our proposed ROE, our customers still benefit from having a weighted average cost of capital that is among the lowest in the state.

Q, What action is Gulf taking to achieve this capital structure?

A. During 2016, Gulf has increased its equity from the level at year-end 2015 by retaining additional earnings. In addition to equity infusions for general business purposes, Gulf will take an equity infusion of approximately $150 million in or before January 2017 to achieve the 53 percent equity ratio.

Q. What is the effect of this planned increase in equity on Gulf's overall jurisdictional capital structure?

A. Gulf's jurisdictional capital structure includes both investor and non-investor sources of capital. While common equity was 46.3 percent of investor-supplied capital in Gulf's Commission-approved 2012 capital structure, it was 38.5 percent of total jurisdictional capital. This means that Gulf was earning an equity return on 38.5 percent of its retail rate base.

When the transition is complete, the percentage of equity in Gulf's jurisdictional capital structure for 2017 will increase to 40.1 percent. Gulf will thus earn an equity return on only a slightly higher portion of its rate base than what the Commission approved in 2012. Even with this change and Gulf's proposed ROE, the overall weighted average cost of capital reflected in Gulf's rates will decline from 6.39 percent in 2012 to 6.04 percent in 2017.

Q. How does this jurisdictional capital structure compare to the other Florida IOUs?

A. Gulf currently has a lower proportion of equity in its jurisdictional capital structure than the other Florida IOUs. As shown on Schedule 6 of my exhibit, the other Florida IOUs currently have jurisdictional equity ratios that are six to eleven percentage points greater than Gulf's. After taking into account the new capital structure, Gulf will still have the lowest jurisdictional equity ratio of the major Florida IOUs.

Q. Why is Gulf proposing a change in capital structure at this time?

A. There are several reasons. First, the increased equity ratio will improve Gulf's quantitative credit metrics, increasing the likelihood that Gulf will be able to maintain its targeted credit ratings during a period of continued large capital expenditures. Second, adjusting the equity ratio at this time brings us more in line with other utility peers in the state. This will allow investors to correctly see that the financial risk of investing in Gulf Power is similar to other Florida utilities, permitting them to focus on the quality of Gulf Power's operations. This will bring the total risk that equity investors face onto a level playing field with other Florida utilities, allowing Gulf to access capital on competitive terms. Third, the historic inability of Gulf to earn equity returns that reflected the higher financial risk of its previous capital structure makes it appropriate to adopt a capital structure that is more likely to produce returns that meet the expectations of equity investors.

Even with this capital structure and our proposed ROE, Gulf Power still provides its customers a weighted average cost of capital that is among the lowest of our Florida peers.

Q. What cost of equity is the Company seeking in this case?

A. As Dr. Vander Weide indicates in his testimony, a fair rate of return on common equity is 11.0 percent.

Q. Has Dr. Vander Weide considered the effect of Gulf's increased equity ratio and the resulting impact on its financial risk?

A. Yes. In Gulf's two prior rate cases, Dr. Vander Weide considered the relative financial risk in the capital structures of his proxy group and adjusted Gulf's required return to ensure that equity investors would be compensated for Gulf's higher financial risk. Because the increase in Gulf's equity ratio brings it more in line with the other members of his proxy group, the same analysis in this case results in a lower adjustment.

Q. What is Gulf's cost of debt?

A. As shown on Schedule 14 of Ms. Ritenour's Exhibit SDR-1, Gulf's embedded cost of long-term debt is 4.40 percent. For the test year, we project that our cost of short-term debt will average 3.02 percent.

Q. What is Gulf's weighted average cost of capital for ratemaking purposes?

A. As shown on Schedule 14 of Ms. Ritenour's Exhibit SDR-1, Gulf's weighted average cost of capital is 6.04 percent when taking into account both investor sources of capital (common equity, preference stock, long-term debt and short-term debt) and other sources considered for ratemaking purposes (customer deposits, deferred taxes and investment tax credits).

Q. Is the weighted average cost of capital proposed by Gulf appropriate in this case?

A. Yes. The weighted average cost of capital of 6.04 percent proposed by Gulf will provide debt and equity investors the opportunity to earn a fair return and will allow Gulf's customers to continue to enjoy the benefits of an overall weighted average cost of capital that is among the lowest of the major Florida IOUs.

IX. PARENT DEBT ADJUSTMENT

Q. What is the parent debt adjustment?

A. It is a regulatory adjustment to reduce the amount of income tax expense to be included in rates, pursuant to Commission Rule 25-14.004.

Q. Please provide a brief overview of that rule.

A. The parent debt adjustment rule was adopted by the Commission in 1983. For ease of reference, I have included a copy of that rule as Schedule 7 of my exhibit. This rule applies in rate proceedings where (1) a parent-subsidiary relationship exists, (2) the parent and subsidiary participate in filing a consolidated tax return, and (3) funds provided by parent debt have been invested in the equity of the regulated subsidiary. If all three factors are present, the rule provides a formula for reducing the subsidiary utility's income tax expense to reflect the tax effect of the parent debt that is invested in the equity of the subsidiary.

Q. What is the basis for the rule's adjustment to income tax expense?
A. The premise is that parent debt has been invested in the equity of the regulated subsidiary; thus, the income tax benefit of the interest deduction for the debt should accrue to the regulated subsidiary.

Q. Are the interest costs associated with that parent debt included in rates?
A. No. The interest expense is not included in rates.

Q. Is the parent debt included in the regulated subsidiary's capital structure?
A. No. Only the debt issued by the regulated subsidiary is included in the capital structure used to set rates.

Q. What are the financial implications of making a parent debt adjustment?
A. The parent debt adjustment results in an inconsistency between the federal income tax interest deduction imputed for ratemaking purposes on the one hand and the utility's actual interest expense and capital structure on the other. This inconsistency would have two primary effects. First, imputing to the subsidiary the tax benefits of parent company debt effectively assumes that the Company has more debt in its own capital structure than actually exists. The parent debt adjustment assumes there are tax benefits of parent company debt accruing to the subsidiary without recognizing the associated financial risk of having more debt in its capital structure. Appropriately, the Commission does not impute parent company debt into the subsidiary's capital structure. It would be inappropriate to impute any tax benefits associated with such debt.

Second, by artificially reducing the federal income tax expense used to establish the subsidiary's rates, the adjustment decreases the subsidiary's effective return on equity. Making such an adjustment in this case would reduce Gulf's effective ROE by approximately 61 basis points compared to what the Commission otherwise determines is a fair rate of return.

The Commission should consider these impacts of applying the parent debt rule when weighing the evidence to rebut the presumption that Southern Company's investment in Gulf is funded in part by parent debt.

Q. In calculating Gulf's income tax expense for the test year, Ms. Ritenour does not make a parent debt adjustment under Commission Rule 25-14.004. Why isn't such an adjustment required?

A. The rule does not require an adjustment in this case because only two of the three factors in the rule are met. Gulf is a subsidiary of Southern and it participates in filing a consolidated income tax return; thus the first two factors are met. The third factor is not met because no funds provided by Southern debt have been invested in the equity of Gulf.

Q. Doesn't subsection (3) of the rule create a presumption that Southern's equity investment in Gulf is supported by debt based on the ratio of debt in Southern's overall capital structure?

A. Yes, but the rule also states that the presumption is rebuttable. The presumption can be rebutted—and the rule does not require an adjustment—if the utility shows that the parent's equity investment did not come from debt issued at the parent level. Gulf rebutted this presumption in its 2012 test year rate case, and the factors which were sufficient to rebut the presumption in 2012 still exist for the 2017 test year.

Q. How did the Commission rule on this issue in 2012?

A. The Commission did not make a parent debt adjustment in setting Gulf's rates. In Order No. PSC-12-0179-FOF-EI, the Commission first found that: "On its face, the Parent Debt Adjustment Rule is inconsistent with our long-standing practice of determining allowable utility taxes on a stand-alone basis." (Order at page 114)

After an extensive discussion of the testimony regarding the parent debt adjustment, the Commission concluded that:

> the preponderance of the evidence indicates Gulf effectively has rebutted the presumption that Southern Company invested debt dollars in Gulf's common equity in direct proportion to the percent of debt in Southern Company's parent only capital structure. Consequently, we find that no parent debt adjustment shall be made in the case. (Order at page 116)

Q. What was the basis of that rebuttal?

A. Gulf itself, not Southern debt, had effectively provided the funding for Southern's equity investment in Gulf. Dividend payments made by Gulf to Southern had exceeded the equity investments made by Southern in Gulf.

As shown on Schedule 8 of my exhibit, for the period between Gulf's previous rate case in 2003 and the 2012 case, Gulf had paid $655.8 million in dividends to Southern, while Southern had made equity investments in Gulf of $459.0 million. Thus, Gulf's dividend payments had been sufficient to support 100 percent of Southern's equity investments and still result in a net payment to Southern of $196.8 million. This showed that Gulf itself, not Southern debt, had effectively provided the funding for Southern's equity investment in Gulf.

Q. To rebut the presumption, did Gulf trace the dollars invested by Southern to prove that the investment was sourced by the dividends paid by Gulf, as opposed to Southern debt?

A. No. Dollars are fungible. Tracing dollars to prove that the third factor is met—or not met—is simply not possible. However, the rule cannot properly be interpreted to require an exact tracing. If exact tracing of dollars were required, the presumption in the rule would be effectively irrebuttable. This cannot be what the Commission intended.

Q. Did the Commission address tracing of dollars in the 2012 case?

A. Yes. In Order No. PSC-12-0179-FOF-EI, the Commission stated: "Although funds cannot be traced, it is more logical to assume that Southern Company returned dividend dollars to Gulf to maintain an appropriate level of equity in Gulf than to assume Southern Company issued debt to invest in Gulf's equity." (Order at page 116)

Q. Have the dividends paid by Gulf continued to exceed equity investments made by Southern in Gulf?

A. Yes. Gulf has continued to pay more in dividends to Southern than the amount of Southern's equity investments in Gulf. From April 1, 2011 through December 31, 2015, Gulf has paid dividends in the amount of $567.1 million while Southern has made equity investments in Gulf in the amount of $150 million.

Q. Does Gulf forecast additional dividends paid to Southern and additional equity investments in Gulf by Southern for 2016 and 2017?

A. Yes. As shown on Schedule 8 of my exhibit, between January 1, 2016 and the end of 2017, Gulf is projected to pay dividends to Southern in the amount of $240.7 million while Southern is projected to make equity investments in Gulf of $232.9 million.

In aggregate, dividends paid to Southern are expected to exceed equity investments in Gulf by $621.6 million from 2003 through the end of the test year. Thus, Gulf will continue to be a net returner of capital to Southern, not a net recipient. As in the prior rate cases, Gulf effectively provides the funding for Southern's equity investment in Gulf with its own internally generated funds.

Q. Has the Commission made a parent debt adjustment in any of Gulf's prior rate cases?

A. No. The rule was adopted in 1983. Since that time Gulf has had five rate cases before the Commission, and the Commission has never made a parent debt adjustment pursuant to Rule 25-14.004.

X. SUMMARY

Q. Please summarize your testimony.

A. The rate relief authorized in our last two rate cases does not provide Gulf with sufficient base rate revenues to sustainably provide safe and reliable service to our customers. While Gulf has invested in its systems to provide that service as planned, the revenues required to support that investment have not materialized. Due to the need for continued investment as well as increases in O&M expense, the cost to meet our obligation to serve customers will continue to increase. Projected sales growth simply will not cover that higher cost to serve.

Gulf's rates must be increased to sustain its financial strength to fund investment and O&M expenses. With the expiration of the support mechanisms contained in the approved Settlement from our last case, Gulf's returns will be well below the bottom of our authorized range by the time that new base rates can take effect, and the returns would only continue to decline without rate relief. A weakening financial position would negatively impact the Company’s ability to attract needed capital on reasonable terms and would challenge our long-term ability to provide high quality services to our customers.

It is essential that the Company’s investment in the portion of Scherer 3 that is now serving retail customers be recovered from those customers. Such recovery is not only required by the regulatory compact, but it is also necessary to allow Gulf to continue to consistently take a long-term view when making future investment decisions.

Gulf is in the process of increasing the proportion of equity in its capital structure to 53 percent of investor-supplied sources. This change will reduce Gulf’s financial risk and bring our capital structure more in line with other utilities in Florida. With Gulf’s proposed capital structure and returns, our customers will continue to enjoy the benefits of an overall weighted average cost of capital that is among the lowest of the major Florida IOUs.

Finally, Gulf has shown that, as in its last rate case, the equity investments by Southern are not funded by debt issued at the parent company level. Gulf has thus rebutted the presumption in the parent debt adjustment rule and demonstrated that no adjustment is necessary for ratemaking purposes.

In summary, Gulf is committed not only to meeting the minimum requirements of its obligation to serve, but also to continuing to meet the expectations of high quality service. Gulf is requesting an annual increase of $106.8 million in its retail base revenues in order to do that.

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

GULF POWER COMPANY

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

Q. Please state your name and business address.
A. My name is Jun Park. 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). I serve as Gulf's Supervisor of Forecasting.

Q. What are your responsibilities as Gulf's Supervisor of Forecasting?
A. As Supervisor of Forecasting, I am responsible for leading a team of analysts to produce Gulf's forecast of customers, energy sales, peak demand, and base revenue. In this role, I direct and review the forecast each year as it is developed from beginning to end, provide guidance to the forecast team at important decision points, direct forecast-related analyses and process improvements, brief executive management on forecast development progress, and oversee workflow and staffing.

Q. Please state your prior work experience and responsibilities.
A. I started my career with Southern Company in 1999. Over the course of my career, I have held various positions with forecasting and analytical

responsibilities, including forecasting wholesale energy prices, coordinating the development of price forecasts for fuel commodities and emissions allowances, and developing long-term energy and peak demand forecasts. I joined Gulf Power in 2011 as a forecast analyst and have been leading Gulf's forecasting team since 2014.

Q. What is your educational background?

A. I graduated from the University of Alabama at Birmingham with a Bachelor of Science degree in Finance.

Q. What is the purpose of your testimony?

A. My testimony presents Gulf's forecast methodologies and forecast results for customers, energy sales, peak demand, and base rate revenue. The forecast is provided to Corporate Planning for use in the budgeting and planning process as discussed by Gulf Witness Mason.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit JKP-1, Schedules 1 through 6. Exhibit JKP-1 was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge and belief.

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

A. Yes. The MFRs I sponsor or co-sponsor are listed in Schedule 1 of my exhibit. The information contained in the MFRs I sponsor or co-sponsor is true and correct to the best of my knowledge and belief.

I. OVERVIEW

Overview of Economic Conditions and Historical Sales Trends

Q. Please describe the economic conditions for Gulf's service area.

A. Gulf provides retail service to customers in eight counties in Northwest Florida (NW FL): Bay, Escambia, Holmes, Jackson, Okaloosa, Santa Rosa, Walton, and Washington. Our service area is generally represented by three Metropolitan Statistical Areas (MSAs): Pensacola-Ferry Pass-Brent, Crestview-Fort Walton Beach-Destin, and Panama City.

Prior to the most recent economic recession, Gulf's service area saw strong economic growth. For the pre-recession years from 2002 to 2006, economic growth was strong, with a compound annual average growth rate (CAGR) of 3.6 percent for non-manufacturing employment, 5.0 percent for real disposable personal income, and 5.5 percent for gross domestic product (GDP) for Gulf's MSAs.

Beginning in late 2006 and continuing through 2012, economic conditions in Gulf's service area deteriorated significantly. Employment and GDP fell at an average annual rate of 1.0 percent and 1.9 percent, respectively, and income growth slowed to just 0.9 percent per year.

Since 2012, economic conditions have improved somewhat, but growth still remains below pre-recession rates. Growth rates for the years 2012 to 2015 have been generally less than half that of pre-recession levels, with annual average growth rates of only 1.9 percent per year for GDP and average annual growth rates for employment and income of just 1.5 percent.

Q. Please describe Gulf's historical sales trends.

A. Gulf's sales trends were generally similar to economic performance measures for the overall NW FL economy, with Gulf's retail energy sales experiencing average annual growth of 1.8 percent during the pre-recession years from 2002 to 2006. Gulf's retail energy sales dropped significantly through the recession, with an average annual decline of 0.9 percent. Since 2012, retail sales have remained relatively flat at an average annual growth rate of less than one half of a percent.

Q. How do these historical sales compare to the forecasts for retail energy sales in Gulf's 2012 test year rate case (Docket No. 110138-EI)?

A. Actual retail energy sales during 2012 were significantly below forecasts because the economic growth during that time was slower than projected.

Weather-normalized retail energy sales have continued to remain relatively flat and have not reached the levels projected for the 2012 test year in Gulf's 2012 test year rate case.

Q. Why have retail sales remained relatively flat since 2012?

A. Declining use per customer was the overwhelming driver for the relatively flat retail sales since 2012. As shown in Schedule 2 of my exhibit, residential use per customer has declined an average of 0.7 percent per year since 2012, compared to an average annual residential customer growth of 1.0 percent for the same period. Schedule 3 of my exhibit shows similar trends for the commercial class, where commercial use per customer declined an average of 1.1 percent since 2012, compared to an average commercial customer growth of 1.1 percent.

Q. What factors contributed to the declines in use per customer?

A. The economic slowdown experienced during the recent recession and the subsequent sluggish recovery significantly impacted Gulf's use per customer. Additional declines in use per customer were driven by improvements to overall equipment efficiencies due to changes in minimum codes and standards for new equipment such as HVAC units and lighting.

Q. How did the energy sales forecast used in Gulf's last base rate proceeding compare to actual results?

A. The forecast for the 2014 test year used in Gulf's last base rate proceeding (Docket No. 130140-EI) was accurate, as Gulf minimally over-forecast retail energy sales by 0.8 percent.

<u>Economic Outlook and Sales Growth Expectations</u>

Q. Please describe the economic outlook for Gulf's service area used to develop Gulf's forecast in this case.

A. The economic projections used by Gulf are from Moody's Analytics, a well-respected economic forecasting firm that has supplied Gulf with economic forecasts for over 20 years. Gulf used the October 2015 vintage of Moody's economic projections, which were the most current data available at the time the forecast was developed. In that outlook, Moody's projects that the economy in Gulf's service area will grow in 2016 and experience improved growth in 2017.

Q. Please summarize Gulf's sales growth expectations in its forecast.

A. Retail sales are expected to grow at a CAGR of 0.2 percent over the next two years.

Q. Is there a risk that Gulf's actual sales over the next two years might differ from Gulf's forecast for the same period?

A. Yes. There is always an element of risk in forecasting due to a variety of factors such as declining use per customer and economic uncertainty. For example, Gulf's most recent forecast of retail base rate revenues for 2017 is 1.0 percent lower than the forecast for this base rate proceeding, which equates to $5.7 million less in projected base rate revenues for the 2017 test year. Despite the continuing trend of flat or declining use per customer along with the challenging economic conditions experienced over the most recent years, Gulf's forecast methodology is fundamentally sound and is the most accurate tool available for forecasting the Company's future energy sales.

<u>Overview of Forecast Methodology</u>

Q. Please provide an overview of Gulf's forecast methodology.

A. Each year, Gulf produces a new forecast. Gulf starts with a projection of the number of customers it expects to add in each customer class. Next, Gulf estimates how much energy these customers will use under normal weather conditions. For customers on demand rates, Gulf then estimates monthly billing demands. Finally, the base charge, energy charge, and demand charge from the appropriate rate schedules are applied to the number of customers, monthly energy, and monthly billing demands to estimate base rate revenue. Gulf also forecasts total Company peak demand using total energy projections and historical relationships between energy and demand. This same fundamental methodology has been used by Gulf to develop the forecast for over 20 years. Minor refinements to model specifications have been made over those years, but the fundamental methods have remained unchanged and continue to produce reliable forecasts. Refinements in the model specifications made since Gulf's last base rate case are described later in my testimony.

Q. Has the previously described forecast methodology for customers, energy, peak demand, and base revenue been used by Gulf in its regular course of business?

A. Yes. Gulf produces a forecast annually using this same methodology. The annual forecast is routinely utilized for business planning and operations. This forecast is used by the Company for financial planning; budgeting; generation, distribution and transmission planning; and fuel procurement planning.

Q. Has the previously described forecast methodology for customers, energy, peak demand, and base revenue been used by Gulf in base rate proceedings where the Florida Public Service Commission (FPSC or the Commission) has accepted, approved, or relied upon Gulf's forecast?

A. Yes. This forecast methodology was used by Gulf in its 2012 test year rate case where it was stipulated to by the parties and approved by the Commission. This methodology was also used in Gulf's most recent base rate proceeding which was settled by the parties.

Q. Has the previously described forecast methodology for customers, energy, peak demand, and base revenue been used by Gulf in other proceedings or filings where the Commission has accepted, approved, or relied upon Gulf's forecast?

A. Yes. This methodology has also been used by the Company over the years for various purposes including: Ten Year Site Plan filings; need determination proceedings; Renewable Standard Offer Contract filings; and annual cost recovery filings for Gulf's clauses.

II. GULF'S CUSTOMER FORECAST

Q. What are the 2017 results of Gulf's customer forecast?

A. Gulf projects that it will have a total of 460,850 retail customers by December 2017, an increase of 6,682 customers over projections for December 2016. This represents an anticipated annual growth rate of 1.5 percent for the test year. By comparison, historical growth rates of 0.5 percent, 1.1 percent, 1.1 percent and 1.2 percent were experienced in 2012, 2013, 2014 and 2015, respectively. Projections for year-end 2016 indicate an annual growth rate of 1.0 percent.

Q. How were Gulf's forecasts of customers and customer growth for 2016 and 2017 developed?

A. The short-term forecasts of residential, commercial, and industrial non-lighting customers were based primarily on input from Gulf's field Marketing Managers with the assistance of their field employees. These field managers and their employees have frequent and consistent interaction with our customers as part of their daily job tasks. The three managers' combined direct experience with Gulf's customers and markets exceeds three quarters of a century. The projections prepared by these managers reflect recent historical trends in net customer gains as well as anticipated effects of changes in the local economy, the real estate market, planned construction projects, and factors affecting population such as military personnel movements and changes in local industrial production.

Forecasters supplied field managers with historical customer gains by rate schedule and summary economic outlooks for the appropriate MSA. After collecting initial input from field managers, forecasters reviewed the one-year-out customer projections by rate schedule, checking for consistency with historical trends, consistency with economic outlooks, and consistency across MSAs. Forecasters then supplied field managers with draft second-year-out customer projections based on number of households from Moody's, which the field managers reviewed and modified as necessary. In this iterative process, forecasters and field managers reviewed the projections until all were satisfied that the projections reflected an unbiased, most-likely estimate.

The strength of the short-term customer projection methodology, which Gulf has employed for more than 30 years, is that information is gathered at the district level and built up to total company. Because Gulf is a relatively small company, it can manage such a localized process without needing to rely primarily on macro-economic projections to estimate residential and commercial customer growth in the short term.

Gulf projected the number of outdoor lighting customers by rate and class based on historical growth rates and input from Gulf's lighting team to gain insight into future trends.

Q. Has this forecast methodology provided reliable forecasts of customers in the past?
A. Yes. For the past three years, Gulf minimally under-forecast residential customer count one year out by 0.1 percent and minimally over-forecast residential customer count two years out by 0.1 percent.

The commercial class is smaller and more diverse than the residential class, which makes projections more difficult. However, despite these challenges, Gulf's forecast methodology has provided reliable forecasts for commercial customers. For the past three years, Gulf minimally under-forecast commercial customer count one year out and two years out by 0.2 percent.

Q. Is this the same forecast methodology for customers and customer growth that Gulf used in its 2014 test year rate case?
A. Yes.

Q. Was the customer and customer growth forecast advanced by Gulf in the 2014 test year rate case relied upon in the settlement of that case?
A. Yes. It was one of the underlying assumptions used for establishing rates approved in the settlement.

Q. How did the forecast of residential and commercial customers used in Gulf's last base rate proceeding compare to actual results?

A. Gulf's forecast of residential and commercial customers in the last base rate proceeding was very accurate. For residential, Gulf minimally over-forecast the customer count one year out by 0.1 percent for 2013, and minimally over-forecast the customer count two years out by 0.3 percent for 2014. For commercial, Gulf minimally under-forecast the customer count one year out by 0.2 percent for 2013, and minimally under-forecast the customer count two years out by 0.2 percent for 2014. Gulf's customer forecast methodology, which relies on the experience and knowledge of our field managers and their employees, has produced reliable, accurate results.

Q. How accurate have the residential and commercial customer forecasts which have been proposed for use in this proceeding been?

A. Over the 11 months of the forecast period for which actual data are available (October 2015 through August 2016), residential customers were minimally under-forecast by 0.2 percent. The forecast of commercial customers was essentially on budget.

III. GULF'S ENERGY SALES FORECAST

Overall Retail Energy Sales Forecast

Q. What are the results of Gulf's retail energy sales forecast for 2017?

A. Based on our forecast used in this case, retail energy sales are expected to total 11,022,525 megawatt hours (MWh) in the test year, representing an increase of 1.1 percent over projections for the twelve months ending in December 2016. This growth is being driven by projected sales to new customers.

The retail MWh sales forecast by class consists of the following:

Residential:	5,357,974 MWh, comprising 48.6 percent;
Commercial:	3,943,439 MWh, comprising 35.8 percent;
Industrial:	1,697,827 MWh, comprising 15.4 percent; and
Street Lighting:	23,285 MWh, comprising 0.2 percent.

Q. Please provide a brief overview of the methodology Gulf used to develop its retail energy sales forecast.

A. Gulf used three multiple linear regression models to estimate residential and commercial non-lighting energy sales, one for residential and two for commercial. For forecasting purposes, the commercial class was split into two groups—small and large.

The primary economic variables used in the models are twelve month moving average electricity price, real disposable income per household for the residential model, and GDP per capita for Gulf's MSAs for the commercial models. Gulf's residential model also includes an energy efficiency variable. Historical and projected data for these variables are incorporated into the models to capture how customers behave in response to changes in these variables. Typically, when price goes up, customers use less energy, and when price goes down, customers use more energy. Typically, when income and GDP go up, customers use more energy, and when they go down, customers use less energy. Typically, when energy efficiency improves, customers use less energy.

Each regression model estimated energy use per customer per day on a billing cycle basis. Multiplying use per customer per day by the appropriate number of billing cycle days in a month and the number of customers produced total energy. The impacts of demand-side management (DSM) efforts and electric vehicle (EV) charging were then incorporated. The resulting energy projection was then adjusted for unbilled sales to yield calendar month projections.

As is standard industry practice, Gulf's residential and commercial energy forecasts assumed normal weather conditions for future projections. Likewise, forecast accuracy calculations compared these normal weather forecasts of energy sales to weather-normalized actual energy sales.

The forecast of sales to small industrial customers was produced in a similar manner using historical growth rates rather than a regression model.

Projections of sales to the largest industrial customers were based on field surveys. Outdoor lighting energy sales were projected by rate and class using historical growth rates and input from Gulf's lighting team. My testimony below further describes Gulf's retail energy sales forecast methodology.

<u>Residential Energy Sales Forecast</u>

Q. How was Gulf's forecast of 2017 residential energy sales developed?

A. The short-term non-lighting residential energy sales forecast was developed using a multiple linear regression model.

Q. What variables were employed by Gulf in the regression model used to develop the residential energy sales forecast?

A. The dependent variable, the quantity being estimated, in the residential energy regression equation was monthly billing cycle energy per customer per billing day. The regression included a constant term and 20 years of historical data for the following variables: billing cycle residential cooling degree hours per billing day for the months March through December, billing cycle residential heating degree hours per billing day for the months November through April, twelve month moving average of real residential electricity price, real disposable income per household, and energy efficiency. Also included in the model was a binary variable for the month of September 2004 to account for the impact of Hurricane Ivan, a binary variable for the months of August 2012 and September 2012 to account for the impact of Hurricane Isaac, an autoregressive term lagged one month to address first-order residual autocorrelation over time, a binary variable for October 1998 to address a model residual in that month, and a binary variable for the combined months of June 2008, July 2008, and August 2008 to address model residuals in those months. These variables were carefully chosen to make the model both simple and statistically robust. Variables were required to have a logical connection to residential electricity sales, substantial data history, dependable projections of future values, limited overlap with other variables (i.e. limited multicollinearity), and good statistical significance (i.e. low p-value).

Page 1 of Schedule 4 of my exhibit is a graph comparing the residential regression model's predicted values with actual historical data. It shows how well the model's output "fits" history. Page 2 of Schedule 4 of my exhibit is a list of statistics associated with the residential regression model.

Q. Please describe the primary statistical tests Gulf used to evaluate each regression model for reasonableness.

A. Time series multiple linear regression models and their components are typically evaluated for reasonableness using the following statistics: p-value, adjusted R-squared, and the Durbin-Watson d-statistic. Standard statistical software packages routinely provide these statistics as part of their output.

A p-value is computed for each independent variable in a regression model indicating the level of statistical significance of that variable. The p-value can range from 0 to 100 percent. A low p-value indicates a desired result, meaning that the variable is statistically significant.

An adjusted R-squared value, also called a "goodness of fit" test, is calculated for each regression model. A model is considered a "good fit" if its adjusted R-squared is high. R-squared values range from 0 to 100 percent. A regression model that fits the historical data perfectly would have an R-squared value of 100 percent.

The Durbin-Watson d-statistic is calculated for each regression model. The calculation results in a number ranging in value between zero and four. A d-statistic value near two indicates a desired result and implies no autocorrelation in the regression model residuals, i.e., residuals in one time period are not related to residuals in the previous time period.

Q. What statistical results did Gulf attain with the residential regression model?

A. As presented on page 2 of Schedule 4 of my exhibit, all variables used in the residential regression model were statistically significant (i.e. low p-values) and each coefficient had the expected sign. The model's adjusted R-squared was 98.6 percent, indicating that all but 1.4 percent of the variance in the historical data was explained by the model. The model's Durbin-Watson d-statistic was 2.02, indicating no significant autocorrelation in the residuals. Overall, these are excellent statistical results.

Q. What data sources were employed for the economic variables used in Gulf's residential regression model?

A. Historical values and forecast projections of the economic variables real disposable income, households, and GDP price deflator were purchased from Moody's Analytics. Gulf used the October 2015 vintage of Moody's economic projections, which was the most recent data available at the time the forecast was developed.

Q. Previously, when describing the variables used for the forecast, you mentioned an energy efficiency variable. What is the purpose of the energy efficiency variable?

A. The purpose of the energy efficiency variable is to estimate the impact of changes in minimum codes and standards for new equipment, such as HVAC and lighting.

Q. How was the energy efficiency variable calculated?

A. The energy efficiency variable is calculated based upon the federal minimum SEER rating for HVAC units and the average life expectancy of an HVAC unit. The variable accounts for the effect that energy efficiency code changes have on electricity sales.

Q. How was the number of cycle billing days per month determined?

A. Gulf's customers are divided among 21 bill groups. Each bill group has a different scheduled read date, which varies from month to month and is staggered from bill group to bill group. Monthly cycle billing days were calculated as follows. For a given month, the number of billing days in a bill group was the sum of the days from the day after the prior month's scheduled read date through the current month's scheduled read date. These summed days for each of the 21 bill groups were then totaled and divided by 21 to get the month's cycle billing days.

Q. How was historical residential weather calculated?

A. Cooling and heating degree hours were calculated using the National Oceanic and Atmospheric Administration's (NOAA) Pensacola weather station's hourly temperatures. Residential cooling degree hours are the result of taking the number of degrees Fahrenheit that each hourly temperature is above a 67 degree baseline and summing over a given time period. Residential heating degree hours are the result of taking the number of degrees Fahrenheit that each hourly temperature is below a 59 degree baseline and summing over a given time period. These residential cooling and heating degree hour temperature baselines reflect the observed correlation between hourly temperatures and hourly energy purchases by Gulf's residential customers.

Monthly billing cycle residential weather was calculated as follows. For each bill group, the total residential cooling degree hours were summed over the period from the day after the prior month's scheduled read date through the current month's scheduled read date. These summed residential cooling degree hours for each of the 21 bill groups were then totaled and divided by 21 to get the monthly billing cycle residential cooling degree hours. This process was repeated to calculate the monthly billing cycle residential heating degree hours.

Q. Given the strong dependence of residential energy use on weather, what weather forecast was used in the residential energy projection?

A. As is standard practice in the industry, Gulf used “normal” weather in its energy forecasts, where “normal” is defined as a long-term average of historical weather. Monthly normal weather for the residential class was developed using historical monthly cycle residential cooling and heating degree hours per billing day averaged by month over the past 20 years.

Q. How was the residential regression model output used to develop the residential energy forecast?

A. The residential regression model output, i.e., monthly billing cycle energy per customer per billing day, was multiplied by the projected number of non-lighting residential customers and projected cycle billing days by month. The residential class outdoor lighting energy projection was then added to produce the total residential class energy projection. The total residential class energy projection was then adjusted to reflect the anticipated impacts of Gulf’s DSM plan and the introduction of electric vehicles to the market. A projection of unbilled energy was then added to the resulting billed energy projection to develop a calendar month projection of total residential class energy. Residential energy sales by rate were developed using average historical use per customer by rate.

Q. What DSM plan assumptions were included in Gulf's forecast?

A. Gulf utilized its most recent DSM plan, which was approved by the Commission in Order No. PSC-15-0330-PAA-EG on August 19, 2015, to adjust forecasted sales and annual system peak demand for projected conservation impacts. These assumptions for conservation impacts are reasonable and in accordance with the past methodology included in the forecast used in Gulf's last rate case.

Q. Please address the anticipated impacts of Gulf's DSM plan on the residential energy forecast.

A. The forecast reflects all expected impacts of the DSM plan – some of those impacts were embedded in the regression model output and some of those impacts were included through an exogenous adjustment to the regression model output. Gulf utilized data from ITRON (the vendor used by parties in the DSM goals docket to develop technical and achievable potential levels of DSM for Gulf and other utilities) as well as Gulf's experience in the energy efficiency market and knowledge of existing programs to determine, by program, the amount of energy savings embedded in the historical regression data. The remaining impacts, those not embedded in the historical data, formed the exogenous DSM adjustment. The exogenous DSM adjustment to residential class energy in the test year was 9 million kWh, which reduced total retail energy sales by 0.2 percent.

Q. How did Gulf project the impact of electric vehicles in its residential energy forecast?

A. Gulf used a purchased study from the Electric Power Research Institute to estimate the impact of electric vehicles on retail sales. The study estimated an exogenous impact of 3.6 million kWh in the test year. All charging was assumed to occur off-peak in the residential class.

Q. Did the proposed changes to the residential pricing structure and new conservation programs result in additional adjustments to the residential energy forecast?

A. No. The changes to the residential pricing structure proposed by Gulf Witness McGee are projected to result in a slight increase in residential energy sales in the test year but those increases in sales are more than offset by the energy savings from the new and modified residential DSM programs proposed by Gulf Witness Floyd. As a result, no additional adjustments to the residential energy forecast were necessary.

Commercial Energy Sales Forecast

Q. How was Gulf's forecast of 2017 commercial energy sales developed?

A. The short-term non-lighting commercial energy sales forecast was developed using two multiple linear regression models. One modeled "small commercial" customer energy usage (rate schedules GS and Flat-GS), and the other modeled energy usage of the remainder of the commercial class (all other rate schedules), the latter being referred to as "large commercial." Both models were similar in specification.

Q. What variables were employed by Gulf in the two regression models used to develop the commercial energy sales forecast?

A. In each commercial regression model, the dependent variable (the quantity being estimated) was monthly billing cycle energy per customer per billing day. The small commercial model included a constant term and 20 years of historical data for the following variables: billing cycle cooling degree hours per billing day for the months of April through November, billing cycle heating degree hours per billing day for the months of December through April, twelve month moving average of real commercial electricity price, and GDP per capita for Gulf's MSAs. Also included in the small commercial model was a binary variable for the month of September 2004 to account for the impact of Hurricane Ivan, a binary variable for the month of August 1997 to address a large residual in that month, a binary to account for residuals beginning in May 2012, and one autoregressive term lagged one month to address first-order residual autocorrelation over time.

The large commercial model included a constant term and 20 years of historical data for the following variables: billing cycle cooling degree hours per billing day for the months of March through November, billing cycle heating degree hours per billing day for the months of December through March, a binary variable to capture the seasonal variation for the month of January, twelve month moving average of real commercial electricity price, and GDP per capita for Gulf's MSAs. Also included in the large commercial model was a binary variable for the month of September 2004 to account for the impact of Hurricane Ivan, a binary to account for residuals beginning in

May 2012, and one autoregressive term lagged one month to address first-order residual autocorrelation over time.

These variables were carefully chosen to make the commercial models both simple and statistically robust. Variables were required to have a logical connection to commercial electricity sales, substantial data history, dependable projections of future values, limited overlap with other variables (i.e. limited multicollinearity), and good statistical significance (i.e. low p-value).

Page 1 of Schedule 5 of my exhibit is a graph comparing the small commercial regression model's predicted values with actual historical data. It shows how well the model's output "fits" history. Page 2 of Schedule 5 of my exhibit is a list of statistics associated with the small commercial regression model.

Page 1 of Schedule 6 of my exhibit is a graph comparing the large commercial regression model's predicted values with actual historical data. It shows how well the model's output "fits" history. Page 2 of Schedule 6 of my exhibit is a list of statistics associated with the large commercial regression model.

Q. What statistical results did Gulf attain with the small commercial regression model?

A. As presented on page 2 of Schedule 5 of my exhibit, all variables used in the small commercial regression model were statistically significant (i.e. low p-values) and each coefficient had the expected sign. The model's adjusted R-squared was 95.0 percent, indicating that all but 5.0 percent of the variance in the historical data was explained by the model. The model's Durbin-Watson d-statistic was 2.25, indicating no significant autocorrelation in the residuals. Overall, these are excellent statistical results.

Q. What statistical results did Gulf attain with the large commercial regression model?

A. As presented on page 2 of Schedule 6 of my exhibit, all variables used in the large commercial regression model were statistically significant (i.e., low p-values) and each coefficient had the expected sign. The model's adjusted R-squared was 97.4 percent, indicating that all but 2.6 percent of the variance in the historical data was explained by the model. The model's Durbin-Watson d-statistic was 2.13, indicating no significant autocorrelation in the residuals. Overall, these are excellent statistical results.

Q. What data sources were employed for the economic variables used in Gulf's commercial regression models?

A. Historical values and forecast projections of the economic variables GDP, population, and GDP price deflator were purchased from Moody's Analytics.

Gulf used the October 2015 vintage of Moody's economic projections, which was the most recent data available at the time the forecast was developed.

Q. How was historical commercial weather calculated?

A. Cooling and heating degree hours were calculated using the NOAA Pensacola weather station's hourly temperatures. Commercial cooling degree hours are the result of taking the number of degrees Fahrenheit that each hourly temperature is above a 63 degree baseline and summing over a given time period. Commercial heating degree hours are the result of taking the number of degrees Fahrenheit that each hourly temperature is below a 54 degree baseline and summing over a given time period. These commercial cooling and heating degree hour temperature baselines reflect the observed correlation between hourly temperatures and hourly energy purchases by Gulf's commercial customers. Observed commercial customer temperature breakpoints are lower than residential customer temperature breakpoints because commercial buildings typically contain more heat producing equipment and people than residential buildings. Thus, commercial Heating Ventilating and Air Conditioning (HVAC) equipment typically begins heating later (below a lower temperature) and begins cooling sooner (above a lower temperature) than residential HVAC equipment.

Monthly billing cycle commercial weather was calculated as follows. For each bill group, the total commercial cooling degree hours were summed over the period from the day after the prior month's scheduled read date through the current month's scheduled read date. These summed commercial cooling degree hours for each of the 21 bill groups were then totaled and divided by 21 to get the monthly billing cycle commercial cooling degree hours. This process was repeated to calculate the monthly billing cycle commercial heating degree hours.

Q. How was forecast commercial weather calculated?

A. As is standard practice in the industry, Gulf used “normal” weather in its energy forecasts, where “normal” is defined as a long-term average of historical weather. Monthly normal weather for the commercial class was developed using historical monthly cycle commercial cooling and heating degree hours per billing day averaged by month over the past 20 years.

Q. How were the outputs of the two commercial regression models used to develop the commercial energy forecast?

A. The small commercial regression model output was multiplied by the projected number of non-lighting small commercial customers and projected cycle billing days by month. The large commercial regression model output was multiplied by the projected number of non-lighting large commercial customers and projected cycle billing days by month. These small commercial and large commercial results were then summed. The commercial class outdoor lighting energy projection was then added to produce the total commercial class energy projection. The total commercial class energy projection was then adjusted to reflect the anticipated impacts of Gulf’s DSM plan. A projection of unbilled energy was then added to the resulting billed energy projection to develop a calendar month projection of total commercial class energy. Commercial energy sales by rate were developed using average historical use per customer by rate.

Q. Please address the anticipated impacts of Gulf's DSM plan on the commercial energy forecast.

A. The forecast reflects all expected impacts of the DSM plan – some of those impacts were embedded in the regression model output and some of those impacts were included through an exogenous adjustment to the regression model output. Gulf utilized data from ITRON as well as Gulf's experience in the energy efficiency market and knowledge of existing programs to determine, by program, the amount of energy savings embedded in the historical regression data. The remaining impacts, those not embedded in the historical data, formed the exogenous DSM adjustment. The exogenous DSM adjustment to commercial class energy in the test year was 3 million kWh, which reduced total retail energy sales by 0.1 percent.

<u>Industrial Energy Sales Forecast</u>

Q. How was Gulf's 2017 forecast of industrial energy sales developed?

A. The short-term industrial energy sales forecast was developed using a combination of on-site surveys of major industrial customers and historical average consumption per customer per billing day.

Forty-seven of Gulf's largest industrial customers, representing over 90 percent of the industrial class sales, were interviewed by Gulf's industrial account representatives to identify expected load changes due to equipment additions and replacements or changes in operating schedules and characteristics. The short-term forecast of monthly sales to these major industrial customers was a synthesis of this survey information and historical monthly to annual energy ratios.

The forecast of short-term sales to the remaining smaller industrial customers, which represent 1.6 percent of total retail energy sales, was developed by rate schedule and month using historical averages. The resulting estimates of energy purchases per customer per billing day were multiplied by the expected number of customers and billing days by month to expand to the rate level totals. These projections were then added to the results for the major industrial customers, the industrial class outdoor lighting energy projections, and the industrial class unbilled energy estimates to sum to the industrial class calendar month totals.

Street Lighting Energy Sales Forecast

Q. How was Gulf's 2017 forecast of street lighting energy sales developed?

A. Similar to the outdoor lighting projections for the residential, commercial and industrial classes, Gulf's forecast of street lighting energy sales was developed using a projected growth rate, based on input from Gulf's lighting team, applied to the one rate (OS-I/II) applicable to the street lighting classification.

Total Retail Energy Sales Forecast and Forecast Methodology

Q. How was the total retail energy sales forecast developed?

A. Gulf's total retail energy sales forecast was the result of summing the forecasts of residential, commercial, industrial and street lighting energy sales.

Q. Is this the same forecast methodology for energy sales that was used in Gulf's last base rate proceeding?

A. Yes. The overall methodology that Gulf currently uses to forecast energy sales is substantially the same as that employed in the last base rate proceeding, which was stipulated to by the parties and approved by the Commission. Gulf made two minor changes to its residential model specification during 2015. Both changes were made to the residential regression model to improve the forecast of residential energy sales. The first change to the residential model specification was to add the energy efficiency variable. The continued improvement of efficiency in electric equipment will continue to reduce sales and needed to be reflected in the model. As a result of adding the energy efficiency variable, the split price indices were replaced with a single price variable representing the twelve month moving average of real residential electricity price. It was necessary to remove the split prices because the price increase index and the energy efficiency variable exhibited a high degree of multicollinearity.

The second change to the residential model specification was to add a binary variable for the month of October 1998 to address a model residual in that month. The addition of this variable improved the overall model statistics.

Gulf made three minor changes to the small commercial model specification in 2015 to improve the forecast of small commercial sales. The first change was to replace the economic variable of non-manufacturing employment with GDP per capita for Gulf's MSAs. GDP per capita exhibited a better relationship with commercial energy sales and improved the overall model statistics.

The second change to the small commercial model specification was to add a binary that begins in May of 2012. The binary addresses changes in commercial customer usage that had resulted in actual energy sales coming in under forecast.

The third change to the small commercial model specification was to add heating degree hours for the month of April. Each year, the models are evaluated for potential improvements. Previously, the April heating degree hour variable was not statistically significant. In the model, however, the variable now has a lower p-value, which indicates the variable is statistically significant and warrants inclusion into the small commercial model.

Gulf made three minor changes to the large commercial model specification in 2015 to improve the forecast of large commercial sales. The first change to the large commercial model specification was to replace the economic variable of non-manufacturing employment with GDP per capita for Gulf's MSAs. GDP per capita exhibited a better relationship with commercial energy sales and improved the overall model statistics.

The second change to the large commercial model specification was to add a binary that begins in May of 2012. The binary addresses changes in commercial customer usage that had resulted in actual energy sales coming in under forecast.

The third change to the large commercial model specification was to remove two binaries: the first was for Hurricanes Dennis and Katrina and the second was for Hurricane Isaac. In the model, these variables were no longer statistically significant.

Q. Did you make any adjustments to the forecast besides those already described for DSM, EV charging, and unbilled energy?

A. No. Because the regression equations fit the historical data well, there was no need to adjust the regression outputs.

Q. Has this forecast methodology provided reliable forecasts of retail energy sales in the past?

A. Yes. Gulf's retail energy sales forecasts during the recent recession were higher than actual results because of the lingering effects of the recession, the slower than projected recovery, and unprecedented declines in use per customer. But refinements to model specifications and somewhat lower economic outlook risks have resulted in improvements to Gulf's retail energy sales forecast accuracy. For the past three years, Gulf over-forecast retail sales one year and two years out by 0.9 percent and 3.6 percent, respectively. For the most recent historical year, Gulf minimally under-forecast retail sales one year out by 0.1 percent and minimally over-forecast retail sales two years out by 0.8 percent.

Q. How accurate has the retail energy sales forecast which has been proposed for use in this proceeding been?

A. Over the 11 months of the forecast period for which actual data are available (October 2015 through August 2016), total retail energy sales were slightly under-forecast by 0.8 percent.

Territorial Wholesale Energy Sales Forecast

Q. How was Gulf's forecast of 2017 territorial wholesale energy sales developed?

A. The forecast of territorial wholesale energy sales was developed using a multiple linear regression model.

Q. What variables were employed by Gulf in the regression models used to develop the wholesale energy sales forecast?

A. Monthly wholesale energy purchases per day were estimated based on historical energy sales, residential weather (heating and cooling degree hours), GDP for the applicable MSA, a binary variable corresponding to the wholesale price level, binary variables to account for unusual residuals, and an autoregressive term lagged one month to address first-order residual autocorrelation over time.

Q. What statistical results did Gulf attain with the wholesale regression model?

A. All variables used in the wholesale regression model were statistically significant (i.e., low p-values) and each coefficient had the expected sign. The model's adjusted R-squared value was 95.7 percent, indicating that all but 4.3 percent of the variance in the historical data was explained by the model. The model's Durbin-Watson d-statistic was 2.06, indicating no significant autocorrelation in the residuals. Overall, these are excellent statistical results.

Q. How was the wholesale model output used to develop the total wholesale energy forecast?

A. The model output, monthly energy purchases per day, was multiplied by the projected number of days per month to expand to the total wholesale energy forecast.

Q. What is the importance of the wholesale energy projection in this proceeding?

A. The 2017 wholesale energy projection was used by Gulf Witness O'Sheasy in the cost of service study to develop allocators that help determine the jurisdictional split between the wholesale and retail jurisdictions.

IV. GULF'S PEAK DEMAND FORECAST

Q. What is Gulf's forecasted peak demand for 2017?

A. Gulf's territorial system peak demand is projected to be 2,491 MW in the test year, representing an increase of 41 MW or 1.7 percent over projections for the twelve months ended December 2016. This peak is expected to occur in the summer month of July 2017.

Q. How was this forecast of peak demand developed?

A. The forecast of annual system peak demands was developed using historical load shapes and projections of net energy for load. Net energy for load is the total supply of energy from the generator available to serve territorial customers' load requirements including an estimate for losses. Projected net energy for load was based on the forecasted energy sales described previously in my testimony. Forecasted energy sales were spread using historical hourly load shapes to determine the single highest hour of demand for each month. Gulf's annual system peak demand typically occurs in the month of July. The resulting monthly system peak demand projections were then adjusted to reflect the anticipated impacts of conservation programs from Gulf's DSM plan.

Q. Please address the anticipated impacts of Gulf's DSM plan on the Company's annual system peak demand forecast.

A. The forecast reflects all expected impacts of the DSM plan – some of those impacts were embedded in historical peak demand levels and some of those impacts were included through an adjustment. As with DSM adjustments to energy, data from ITRON, as well as Gulf's experience in the energy efficiency market and knowledge of existing programs, were used to determine, by program, the amount of demand savings embedded in the historical data. The remaining impacts, i.e., those not embedded in the historical data, formed the DSM adjustment. The DSM adjustment to system peak demand in the test year was 5 MW, which reduced system peak demand by 0.2 percent.

V. GULF'S FORECAST OF RETAIL BASE RATE REVENUE

Q. What are the 2017 results of Gulf's retail base rate revenue forecast?

A. Retail base rate revenue is forecasted to total $555,880,000 in the test year. Using rates approved in Gulf's last base rate case in FPSC Order No. PSC-13-0670-S-EI, the base rate revenue forecast by class consists of the following:

Residential:	$338,952,000
Commercial:	$170,550,000
Industrial:	$ 42,455,000
Street Lighting:	$ 3,923,000

Q. Please address how the base rate revenue forecast was developed.

A. Rate schedules approved in Gulf's last base rate case were applied to monthly projections of customers, energy sales, and aggregate billing demands, as applicable by rate, for each customer classification. Outdoor lighting base revenue was estimated by class and rate using the most recent actual base revenue per kWh and guidance from Gulf's lighting team.

Q. What billing components were used to develop the base revenue forecast?

A. The residential monthly billing components consisted of the base charge and the energy charge. The commercial and industrial billing components consisted of the base charge, the energy charge, and, where applicable, the demand charge. The non-residential energy-only time-of-use rate (GSTOU) energy charge included on-peak, intermediate, and off-peak tiers by season. The commercial and industrial demand charge consisted of the max demand charge and, where applicable, the on-peak demand charge and the reactive demand charge. Primary and transmission voltage level discounts were applied to energy and demand charges as appropriate.

Q. How were forecast monthly billing determinants developed for each of these billing components?

A. Forecast year billing determinants were developed for each rate schedule and, where applicable, each voltage discount level as follows:

- Monthly number of customers was derived from the customer forecast.
- Monthly energy was derived from the energy forecast.
    - o Monthly time of use (TOU) energy was based on monthly energy from the forecast allocated to tier based on monthly historical averages by tier.

- Monthly aggregate max demands for commercial and small industrial customers by rate were derived from monthly historical average max demand to energy ratios multiplied by forecast year monthly energy.
- Monthly aggregate on-peak demands for commercial and small industrial customers by rate were derived from monthly historical average on-peak demand to energy ratios multiplied by forecast year monthly energy.
- Monthly max demands, monthly on-peak demands and monthly reactive demands for the 47 largest industrial customers and the eight largest commercial customers were derived from historical ratios applied to projected annual max demands which are collected through the large customer survey.
    - o Monthly max demands for each of these customers were calculated as the product of the forecast year's annual peak demand times the ratio of a historical year's monthly max demand to annual max demand.
    - o Monthly on-peak demands for each of these customers were calculated as the product of the forecast year's monthly max demand times the ratio of a historical year's monthly on-peak demand to monthly max demand.
    - o Monthly reactive demands for each of these customers were calculated as the product of the forecast year's monthly max demand times the ratio of a historical year's monthly reactive demand to monthly max demand.

- The historical year in the billing demand calculations was October 2014 through September 2015, the most recent 12 months of billing data available at the time the billing determinants forecast was developed.

Q. Is this the same forecast methodology for retail base revenue that was used in Gulf's last base rate proceeding?

A. Yes.

Q. How accurate has the retail base revenue forecast which has been proposed for use in this proceeding been?

A. Over the 11 months of the forecast period for which actual data are available (October 2015 through August 2016), total retail base rate revenue was minimally under-forecast by 0.4 percent.

Q. Has the particular forecast proposed in this proceeding been used by Gulf in other recent proceedings or filings before the Commission?

A. Yes. This forecast of customers, energy, and peak demand was the foundation for and was included in Gulf's 2016-2025 Ten Year Site Plan, which was filed with the Commission on April 1, 2016. This forecast of energy and demand was also the basis for calculations used in Gulf's Renewable Standard Offer Contract which was filed with the Commission on April 1, 2016, in Docket No. 160072-EQ and approved by the Commission on June 29, 2016, in Order No. PSC-16-0251-PAA-EQ. This forecast of customers and energy was included in Gulf's Forecasted

Earnings Surveillance Report which was submitted to the Commission staff on March 9, 2016.

Q. Is the forecast prepared by and relied upon by Gulf in this proceeding appropriate for the Commission to use in setting Gulf's base rates?

A. Yes. It is based upon an established and proven methodology. It employed reliable data from well-respected sources. The methodology and forecast are routinely used by Gulf in its regular course of business and were not developed just for this rate case. The methodology and the resulting forecast have been relied upon by Gulf and the Commission in a number of proceedings.

VI. SUMMARY

Q. Please summarize your testimony.

A. Gulf's forecast methodologies are rigorous, statistically significant, and logically connected to the marketplace. Gulf's forecast methodologies are well established. They have been consistently used for many years in substantially the same form and have been reviewed and approved by the Commission in other proceedings. Gulf's methodologies appropriately incorporate adjustments for Gulf's approved DSM plan as well as emerging electric vehicle charging loads. Gulf's forecast methodologies consistently produce accurate results which are routinely used by many departments throughout the Company in the regular course of business. The specific forecast proposed in this proceeding, which has been relied on by the Commission in other filings, is appropriate for use in this base rate proceeding.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

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

Q. Please state your name and business address.

A. My name is Josh Mason. My business address is One Energy Place, Pensacola, Florida 32520.

Q. What is your position?

A. I am the Financial Planning and Budgeting Manager for Gulf Power Company (Gulf or the Company). I also serve as Assistant Treasurer.

Q. What are your responsibilities as Assistant Treasurer and Financial Planning and Budgeting Manager?

A. As Financial Planning and Budgeting Manager, I am responsible for managing the development of financial projections and the performance of financial analysis. I ensure the timely and accurate development of the O&M and capital expenditures budgets for incorporation into Gulf's financial forecast. I am also responsible for various treasury activities at Gulf.

Q. Please state your prior work experience and responsibilities.

A. In 2003 I joined the accounting firm of KPMG LLP in Jacksonville, Florida, as a tax accountant. While at KPMG, I prepared tax returns for publicly traded organizations. I also prepared and reviewed corporate, partnership, insurance, and personal tax returns. In 2005 I returned to Pensacola to work for the regional accounting firm, O'Sullivan Creel, LLP (now Warren Averett) and continued my practice of tax compliance, research and consulting. In 2007 I began employment with Gulf in the Financial Planning department and have held various positions with increasing responsibility, including Financial Analyst, Supervisor of Financial Planning, and now Assistant Treasurer and Financial Planning and Budgeting Manager.

Q. What is your educational background?

A. I graduated from the University of West Florida (UWF) in Pensacola, Florida in 2002 with a Bachelor of Science Degree in Accounting. In 2003, I earned a Master of Accounting Degree from UWF. I am a Certified Public Accountant licensed in the State of Florida, and I hold membership with the American Institute of Certified Public Accountants.

Q. What is the purpose of your testimony?

A. I provide an overview of Gulf's rigorous planning and budgeting process. This process, which Gulf performs annually, uses the component budgets and financial assumptions to produce a financial forecast on which the Company relies to make decisions on how to provide adequate and reliable service to its customers. Specifically, I will describe the Capital Additions and Operations and Maintenance (O&M) Budget processes, set forth the component budgets used in developing the financial forecast, and outline the assumptions used in developing Gulf's financial forecast. The financial forecast is used by Gulf's management for a variety of purposes, and in this instance, it is also the basis for Gulf's projected data for the 2017 test year used in this rate case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit JJM-1, Schedules 1 through 9. Exhibit JJM-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 sponsoring any of the Minimum Filing Requirements (MFRs) submitted by Gulf?

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

I. GULF'S PLANNING AND BUDGETING PROCESS

Q. Please provide an overview and description of Gulf's planning and budgeting process.

A. In order to provide reliable service to its customers at reasonable costs, Gulf's budgeting process is designed to facilitate the Company in producing the most accurate financial forecast, while taking into account economic and financial conditions. This process produces a budget for the current year and a budget forecast for the four subsequent years. These are utilized by management as tools for evaluating and making decisions to ensure the Company provides efficient and reliable service to its customers. The annual 2016 Budget and Forecast, including the forecasted financial statements for the test year, is the basis for Gulf's projected data for the 2017 test year used in this rate case. As discussed by Gulf's other witnesses, both the 2016 and 2017 budgeted levels of O&M and Capital Additions from the 2016 Budget and Forecast are reasonable, prudent and necessary. The budgeting process for 2016 was consistently applied by each Planning Unit at Gulf, which produced reliable results. These results are suitable for establishing the revenue requirements for the 2017 test year.

Q. Please describe Schedule 2 of your exhibit.

A. Schedule 2 is a flow chart of Gulf's annual planning and budgeting process. There are eight component budgets, which are shaded on Schedule 2, that are incorporated into Gulf's financial forecast, which are provided by the Planning Units. The Customer, Energy, and Demand budgets start the process, and these budgets are used as inputs in the derivation of the Revenue, Fuel, Interchange, Capital Additions and O&M Budgets. I am responsible for the financial forecast, which integrates the eight component budgets, along with various other financial assumptions and estimates, and results in projected financial statements. These projected financial statements are then used by Gulf Witness Ritenour to develop the net operating income, rate base, capital structure and revenue requirements that Gulf is requesting in this filing. The Company's budgeting process is the same effective and robust process that was examined and approved in Gulf's previous rate cases.

Q. Who administers the annual planning and budgeting process, and what is Corporate Planning's role in the process?

A. The annual planning and budgeting process is administered by Corporate Planning under the direction of the Chief Financial Officer (CFO), Gulf Witness Liu. As a manager within the Corporate Planning organization, I ensure that Corporate Planning establishes the budget schedule, develops the Budget Message, which is submitted to the CFO for review and approval, and transmits the Budget Message on behalf of the CFO. Corporate Planning also coordinates the Capital Additions and O&M Budget processes, respectively, ensuring that all personnel involved with the processes are kept informed of the key assumptions, goals and any strategic issues facing the Company.

Corporate Planning inputs information from the eight component budgets along with other financial assumptions and estimates into the financial model. Corporate Planning also is responsible for the ongoing process of analyzing and maintaining the financial model to ensure the most accurate forecast based on current assumptions.

Q. Please describe the role of Corporate Planning in preparation of the Capital Additions and O&M component budgets.

A. Corporate Planning is responsible for establishing a process for the preparation of the Capital Additions and O&M Budgets, for administering the process under the direction of the CFO and for preparing the summaries, comparisons, and other information that may be requested. The Executive Management Team (the Chief Executive Officer and the five vice presidents) reviews and approves these budgets. Schedule 3 of Exhibit JJM-1 is a flow chart outlining the Capital Additions and O&M Budget process.

Q. One of the initial steps in the budget process described on your Schedule 3 is the Budget Message. Please describe the Budget Message.

A. Each year, to begin the O&M and Capital Additions Budget process, the Budget Message is provided by the CFO to the Planning Units, which are organizations within the Company that have budget responsibilities. The Budget Message provides budget guidelines, assumptions and other information to be used in the budget preparation process. Corporate Planning assists the CFO in developing the information included in the Budget Message.

Q. Does the Budget Message include a rate of inflation?

A. Yes. The inflation rates for 2016 and 2017 included in the Budget Message were 3.2 percent and 3.7 percent, respectively. These inflation rates are forecasted CPI rates obtained from Moody's Analytics.

Q. How is the rate of inflation used by Gulf in the preparation of its O&M Budget?

A. The inflation rate is provided as part of the Budget Message as an aid to Planning Units in the development of their budget details. However, justification of O&M expenses by the Planning Units requires more than mere escalation by the Consumer Price Index (CPI) or any other measure of inflation. Each Planning Unit develops its O&M budget by examining the activities necessary to meet its goals and objectives, not by simply escalating costs associated with prior periods.

Q. Describe the budget process after the issuance of the Budget Message.

A. This is a multi-step, iterative process. Upon receipt of the Budget Message, each Planning Unit follows its own internal process to prepare its O&M and Capital Additions Budgets. Those internal processes are described in the testimony of other witnesses. However, there is a common element among the processes used by each individual Planning Unit – each Planning Unit closely examines and analyzes the activities necessary to accomplish its goals and objectives and then builds the budgets necessary to meet these responsibilities. Each Planning Unit prepares the detailed budgets that support its goals and objectives. The Vice President for each Planning Unit reviews and, if necessary, modifies that function’s budgets prior to the submission of the Planning Unit’s budgets to Corporate Planning. Corporate Planning reviews submittals for consistency with the Budget Message and compiles the data for review by the CFO and the other executives. Any changes resulting from the executive review and approval process are communicated to the Planning Unit by Corporate Planning. The final approved budgets for O&M and Capital Additions are summarized and communicated to the Planning Units in a letter from the CFO.

Q. Please describe Gulf's Capital Additions Budget.

A. The Capital Additions Budget consists of Plant Expenditures (PEs) for investments that are categorized by function as Production, Transmission, Distribution, and General Plant. The PEs are further identified as Specific PEs and Blanket PEs. Specific PEs are generally individual projects costing $50,000 or more that require expenditures in one or more years. Blanket PEs reflect repetitive expenditures based on historical trends and projected customer growth, such as pole replacements and transformers, that are not identified as individual or separate projects at the time the budget is prepared.

Q. Who is responsible for developing PEs?

A. Planning Units are responsible for developing the PEs for their areas. The majority of the PEs are prepared under the direction of Gulf Witnesses Burroughs and Smith.

Q. Who is responsible for reviewing and approving the overall Capital Additions Budget?

A. Gulf's Executive Management Team reviews all Capital Additions Budget requests. After review and approval by the executives, the Capital Additions Budget is approved annually by the Company's Board of Directors.

Q. Does Gulf monitor the actual construction expenditures against its approved budget?

A. Yes. Corporate Planning monitors and prepares a comparison of actual to budget expenditures each month. For quarter-end months, the Planning Units must submit variance explanations for each PE that has a year-to-date variance that exceeds 10 percent or $250,000, whichever is less. For non-quarter-end months, explanations are required only for variances that exceed $250,000. Variances less than $10,000 do not require an explanation. In addition to researching and explaining year-to-date variances, the appropriate Planning Unit is required to prepare a quarterly estimate of the budget status at year-end or at completion of the project. Corporate Planning is responsible for monitoring the variances and ensuring this process is followed.

Q. What is the amount of Gulf's test year Capital Additions Budget?

A. Gulf's 2017 test year total company Capital Additions Budget is $196,732,000. The 2017 test year Capital Additions Budget, excluding wholesale, cost recovery clauses, non-utility expenditures and test year rate base adjustments is $162,431,000. These projections are shown by major functional category on Schedule 4 of Exhibit JJM-1.

Q. Please describe Gulf's O&M Budget.

A. The O&M Budget consists of expenses required to safely provide efficient and reliable service to Gulf's customers, covering a period of five years. Gulf's Planning Units submit detailed budget requests through the

Company's budget input system. All O&M budget amounts are required to be submitted through this process, with the exception of the fuel and interchange information, which is derived from the Fuel and Interchange component budgets. The O&M Budget is provided to the Executive Management Team for their review and approval.

Q. How does Corporate Planning monitor O&M budget variances?

A. Corporate Planning monitors budget variance reports each month, using Gulf's accounting and reporting system. Each quarter, the Planning Units are required to submit year-to-date reports that include explanations of all variances of 10 percent or more that equal or exceed $25,000. Any variance amount that exceeds $500,000, regardless of the percentage, must also be explained. Projections for the year-end expenses are also submitted quarterly and reviewed by the CFO.

Q. What is the amount of Gulf's test year O&M Budget?

A. The test year System Per Books O&M Budget is $972,265,000, and the test year Total Adjusted O&M Budget is $319,813,000 as shown by major functional category on Schedule 5 of Exhibit JJM-1. The witnesses responsible for O&M expenses by function will address their test year O&M budgets and any O&M benchmark variances. Schedule 21 of Exhibit SDR-1 included in Ms. Ritenour's testimony shows the calculation of Total Adjusted O&M, including each adjustment to O&M expense by function.

Q. Have there been any significant changes in Gulf's budget process since the development of the forecast that was used to support Gulf's last base rate case?

A. No. Gulf's budget process continues to successfully produce reliable budgets and forecasts. Therefore, there have not been any significant changes in Gulf's budget process since the last base rate case, and this process has been consistently applied in preparing the 2016 Budget and Forecast, which includes the 2017 test year.

II. GULF'S FINANCIAL FORECAST

Q. Turning now to the financial forecast, please explain how this forecast is developed.

A. The outputs of the component budgets that I described earlier in my testimony are input into Gulf's financial model. Additionally, various income statement and balance sheet items not captured in the component budgets are analyzed, developed and input into the financial model. The financial model, in turn, processes this data using a number of integrated calculation modules to generate the financial and accounting statements that comprise Gulf's financial forecast. This dynamic iterative process ensures that these various items are consistent with the other budgeted items. For example, forecasted debt issuances and associated interest expense are analyzed and updated when necessary due to other budget changes.

Q. What is the financial model to which you have referred?

A. The financial model is a computer-based model that simulates Gulf's actual financial and accounting results based on a given set of inputs. Schedule 6 of Exhibit JJM-1 is a summarized flowchart of the financial model inputs and outputs required to produce the financial forecast.

Q. Does Gulf prepare financial forecasts for purposes other than rate cases?

A. Yes. Gulf prepares and updates its financial forecast in the regular course of its business to provide management with the most accurate and up-to-date projections to manage the business and to help the Company achieve operational and financial goals.

Gulf uses the financial model to prepare the Annual Budget and Forecast, and also to update financial projections. These financial forecasts are also used for external purposes such as analyst earnings calls, rating agency information, forecasted earnings surveillance reports filed with the Florida Public Service Commission (FPSC or the Commission), and other financial requests.

Q. Please describe the financial statements shown on Schedules 7 and 8 of your exhibit.

A. Schedule 7 is Gulf's projected monthly Balance Sheet for the period December 2016 through December 2017, which is the basis for developing the test year rate base and capital structure. Schedule 8 is the projected monthly Income Statement for the twelve months ended December 31, 2017 used in developing net operating income. These financial statements from the financial model are based on current budget estimates for 2017 from the 2016 Budget and Forecast.

Q. You have summarized utility plant data on your Schedule 7. Have you prepared a report with a further breakdown of the plant balances?

A. Yes. Schedule 9 of Exhibit JJM-1 presents a further breakdown of the utility plant balances along with the monthly activity in these accounts for the test period. The projected plant data is based on the approved Capital Additions Budget, which is supported by various witnesses as noted on Exhibit JJM-1, Schedule 4.

Q. Has Gulf Power filed a list of the assumptions used in developing its financial forecast?

A. Yes. MFR F-8 lists the assumptions used in developing Gulf's financial forecast and the supporting basis for each assumption. The assumptions used in this financial forecast, as outlined on MFR F-8, are reasonable based on our experience and consideration of the circumstances known or anticipated at the time the assumptions were developed.

Q. Please summarize your testimony.

A. Gulf utilizes a very straightforward, logical and comprehensive budget and financial forecasting process. This process is performed annually and results in a forecast that management uses as a tool in planning and decision making. The assumptions contained in the budget process are reasonable, and the resulting financial forecast provides a reasonable and sound basis for projecting the results of Gulf's operations during the 2017 test year as incorporated in the MFRs, testimony and exhibits filed in this case.

Q. Does that conclude your testimony?

A. Yes.

GULF POWER COMPANY

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

I. INTRODUCTION AND PURPOSE

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

A. My name is James H. Vander Weide. I am President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q. Please describe your educational background and prior academic experience.

A. I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, Professor, and then Research Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than thirty-five years. I am now retired from my teaching duties at Duke. A summary of my research, teaching, and other professional experience is presented in Exhibit JVW-2, Appendix 1.

Q. Have you previously testified on financial or economic issues?
A. Yes. As an expert on financial and economic theory and practice, I have participated in five hundred regulatory and legal proceedings before the public service commissions of forty-five states and four Canadian provinces, the Federal Energy Regulatory Commission, the National Energy Board (Canada), the Federal Communications Commission, the Canadian Radio-Television and Telecommunications Commission, the United States Congress, the National Telecommunications and Information Administration, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, I have prepared expert testimony in proceedings before the United States District Court for the District of Nebraska; the United States District Court for the District of New Hampshire; the United States District Court for the District of Northern Illinois; the United States District Court for the Eastern District of North Carolina; the Montana Second Judicial District Court, Silver Bow County; the United States District Court for the Northern District of California; the Superior Court, North Carolina; the United States Bankruptcy Court for the Southern District of West Virginia; the United States District Court for the Eastern District of Michigan; and the Supreme Court of the State of New York.

Q. What is the purpose of your testimony?
A. I have been asked by Gulf Power Company (Gulf or the Company) to prepare an independent appraisal of Gulf's cost of equity and to recommend

to the Florida Public Service Commission (“FPSC” or “the Commission”) a rate of return on equity that is fair, that allows Gulf to attract capital on reasonable terms, and that allows Gulf to maintain its financial integrity.

II. SUMMARY OF TESTIMONY

Q. How do you estimate Gulf’s cost of equity?

A. I estimate the cost of equity for Gulf by applying several standard cost of equity methods to market data for a large group of utility companies of comparable risk.

Q. Why do you apply your cost of equity methods to a large group of comparable risk companies rather than solely to Gulf?

A. I apply my cost of equity methods to a large group of comparable risk companies because standard cost of equity methods such as the discounted cash flow (DCF), risk premium, and capital asset pricing model (CAPM) require inputs of quantities that are not easily measured. The problem of difficult-to-measure inputs is especially acute for Gulf because Gulf does not have publicly-traded stock. Because these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies.

Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to a group of comparable companies. In utility regulation, the practice of using a group of comparable companies, called the comparable company approach, is further supported by the United States Supreme Court standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk. *See Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923) and *Hope Natural Gas Co*., 320 U.S. 561, 603 (1944).

Q. What cost of equity do you find for your comparable companies in this proceeding?

A. On the basis of my studies, I find that the cost of equity for my comparable companies is 10.4 percent. This conclusion is based on my application of standard cost of equity estimation techniques, including the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of companies of comparable business risk. As noted below, the cost of equity for my proxy companies must be adjusted to reflect the higher financial risk associated with Gulf's rate making capital structure compared to the financial risk associated with the average market-value capital structure of my proxy company group. Making this adjustment produces a cost of equity for Gulf equal to 11.0 percent. I therefore conclude that Gulf's fair rate of return on equity is equal to 11.0 percent.

Q. You have adjusted the cost of equity of your proxy companies to reflect the higher financial risk in Gulf's rate making capital structure. Why is that adjustment needed?

A. The cost of equity for my proxy companies depends on their financial risk, which is measured by the market values of debt and equity in their capital structures. The financial risk of my proxy companies is less than the financial risk associated with Gulf's recommended rate making capital structure because Gulf's recommended rate making capital structure contains a higher percentage of debt and a lower percentage of equity than the average market value capital structure of the proxy group. It is both logically and economically inconsistent to apply a cost of equity developed for a sample of companies with a specific degree of financial risk to a capital structure with a different financial risk. One must adjust the cost of equity for my proxy companies upward in order for investors in Gulf to have an opportunity to earn a return on their investment in Gulf that is commensurate with returns they could earn on other investments of comparable risk.

Q. How does Gulf's financial risk, as reflected in its rate making capital structure, compare to the financial risk of your proxy companies?

A. Gulf's rate making capital structure in this proceeding contains 40.77 percent long-term debt, 5.27 percent preferred stock, and 53.96 percent common equity. The current average market value capital structure for my proxy group of companies contains approximately 35.06 percent long-term debt, 0.19 percent preferred stock, and

64.74 percent common equity. Because current market values of equity are at historically high levels, I have also examined the average market value capital structure for the Value Line electric utilities over a ten-year period; and I find that the average market value capital structure for the Value Line electric utilities contains approximately 39.49 percent long-term debt, 0.51 percent preferred stock, and 60.0 percent equity. Thus, the financial risk of Gulf as reflected in its rate making capital structure is greater than the financial risk embodied in the cost of equity estimates for my proxy companies.

Q. What is the fair rate of return on equity for Gulf indicated by your cost of equity analysis?

A. My analysis indicates that Gulf would require a fair rate of return on equity equal to 11.0 percent.

Q. Do you have exhibits accompanying your testimony?

A. Yes. I have prepared or supervised the preparation of Exhibit JVW-1 consisting of 10 schedules and Exhibit JVW-2 consisting of five appendices that accompany my testimony. The information contained in my exhibits is true and correct to the best of my knowledge and belief.

III. ECONOMIC AND LEGAL PRINCIPLES

Q. How do economists define the required rate of return, or cost of capital, associated with particular investment decisions such as the decision to invest in electric utility plant and equipment?

A. Economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

Q. How does the cost of capital affect a firm's investment decisions?

A. The goal of a firm is to maximize the value of the firm. This goal can be accomplished by investing only in that plant and equipment with an expected rate of return that is equal to or greater than the cost of capital. Thus, a firm should continue to invest in plant and equipment only so long as the return on its investment is greater than or equal to its cost of capital.

Q. How does the cost of capital affect investors' willingness to invest in a company?

A. The cost of capital measures the return investors can expect on investments of comparable risk. The cost of capital also measures the required rate of return on investment because rational investors will not invest if they expect a return that is less than the cost of capital. Thus, the cost of capital is a hurdle rate for both investors and the firm.

Q. Do all investors have the same position in the firm?

A. No. Debt investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have a residual claim on the firm's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

Q. What is the overall or average cost of capital?

A. The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

Q. Can you illustrate the calculation of the overall or weighted average cost of capital?

A. Yes. Assume that the cost of debt is 7 percent, the cost of equity is 13 percent, and the percentages of debt and equity in the firm's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by 0.50 times 7 percent plus 0.50 times 13 percent, or 10.0 percent.

Q. How do economists define the cost of equity?

A. Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt.

However, as I have already noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Q. How do economists measure the percentages of debt and equity in a firm's capital structure?

A. Economists measure the percentages of debt and equity in a firm's capital structure by first calculating the market value of the firm's debt and the market value of its equity. Economists then calculate the percentage of debt by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market value of debt and equity. For example, if a firm's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains twenty-five percent debt and seventy-five percent equity.

Q. Why do economists measure a firm's capital structure in terms of the market values of its debt and equity?

A. Economists measure a firm's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q. Why do investors measure the expected return and risk on their investment portfolios using market value weights rather than book value weights?

A. Investors measure the expected return and risk on their investment portfolios using market value weights because: (1) the expected return on a portfolio is calculated by comparing the expected value of the portfolio at the end of the investment period to its current value; (2) the risk of a portfolio is calculated by examining the variability of the end-of-period return on the portfolio about the expected value; and (3) market values are the best measure of the current value of the portfolio. From the investor's point of view, the historical cost, or book value of the investment, is generally a poor indicator of the portfolio's current market value and irrelevant for the purpose of assessing the required return and risk on their portfolios. If they were to sell their investments, they would receive market value, not historical cost. Thus, the return can only be measured in terms of market values.

Q. Is the economic definition of the weighted average cost of capital consistent with regulators' traditional definition of the average cost of capital?

A. No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book values of debt and equity in a company's capital structure.

Q. Will investors have an opportunity to earn a fair return on the value of their equity investment in the company if regulators calculate the weighted average cost of capital using the book value of equity in the company's capital structure?

A. No. Investors will only have an opportunity to earn a fair return on the value of their equity investment if regulators either: (1) calculate the weighted average cost of capital using the market value of equity in the company's capital structure; or (2) adjust the cost of equity for the difference between the financial risk reflected in the market value capital structures of the proxy companies and the financial risk reflected in the company's ratemaking capital structure.

Q. Are the economic principles regarding the fair return for capital recognized in any United States Supreme court cases?

A. Yes. These economic principles, relating to the supply of and demand for capital, are recognized in two United States Supreme Court cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. *of W. Va.*; and (2) *Federal Power Comm'n v. Hope Natural Gas Co*. In *Bluefield Water Works*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties. [*Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).]

The Court clearly recognizes here that: (1) a regulated firm cannot remain financially sound unless the return it is allowed to earn on the value of its property is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated firm will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of the same risk (the principle relating to the supply of capital).

In the *Hope Natural Gas* case, the Court reiterates the financial soundness and capital attraction principles of *Bluefield Water Works*:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [*Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).]

The Court clearly recognizes that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

IV. BUSINESS AND FINANCIAL RISKS

Q. How do investors estimate the expected rate of return on specific investments, such as an investment in Gulf?

A. Investors estimate the expected rate of return in several steps. First, they estimate the amount of their investment in the company. Second, they estimate the timing and amounts of the cash flows they expect to receive from their investment over the life of the investment. Third, they determine the return, or discount rate, that equates the present value of the expected cash receipts from their investment in the company to the current value of their investment in the company.

Q. Are the returns on investment opportunities, such as an investment in Gulf, known with certainty at the time the investment is made?

A. No. The return on an investment in Gulf depends on the Company's expected future cash flows over the life of the investment, as discussed above. Since the Company's expected future cash flows are uncertain at the time the investment is made, the return on the investment is also uncertain.

Q. You note that investors require a return on investment that is equal to the return they expect to receive on other investments of similar risk. Does the required return on an investment depend on the risk of that investment?

A. Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q. What fundamental risk do investors face when they invest in a company such as Gulf?

A. Investors face the fundamental risk that their realized, or actual, return on investment will be less than their required return on investment.

Q. How do investors measure investment risk?

A. Investors generally measure investment risk by estimating the probability, or likelihood, of earning less than the required return on investment. For investments with potential returns distributed symmetrically about the expected, or mean, return, investors can also measure investment risk by estimating the variance, or volatility, of the potential return on investment.

Q. Do investors distinguish between business and financial risk?

A. Yes. Business risk is the underlying risk that investors will earn less than their required return on investment when the investment is financed entirely with equity. Financial risk is the additional risk of earning less than the required return when the investment is financed with both fixed-cost debt and equity.

Q. What are the primary determinants of an electric utility's business risk?

A. The business risk of investing in electric utility companies such as Gulf is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

Q. What causes the demand for electricity to be uncertain?

A. Electric utilities experience demand uncertainty in both the short run and the long run. Short-run demand uncertainty is caused by the strong dependence of electric demand on the state of the economy and weather patterns. Long-run demand uncertainty is caused by: (1) the sensitivity of demand to changes in rates; (2) the efforts of customers to conserve energy; (3) the potential development of new energy efficient technologies and appliances; (4) the improved economics of distributed generation; (5) the ability of some customers to co-generate their own electricity or purchase electricity from competitors; and (6) the uncertain impact of changing governmental regulations and subsidies on the price of electricity.

Q. How does short-run demand uncertainty affect an electric utility's business risk?

A. Short-run demand uncertainty affects an electric utility's business risk through its impact on the variability of the company's revenues and its return on investment. The greater the short-run uncertainty in demand the greater is the uncertainty in the company's yearly revenues and return on investment.

Q. How does long-run demand uncertainty affect an electric utility's business risk?

A. Long-run demand uncertainty affects an electric utility's business risk through its impact on the utility's revenues over the life of its plant investments. Long-run demand uncertainty creates greater risk for electric utilities because investments in electric utility infrastructure are long-lived and irreversible. If demand turns out to be less than expected over the life of the investment, the utility may not be able to generate sufficient revenues over the life of the investment to cover its operating expenses and earn a fair return on its investment.

Q. Does Gulf experience demand uncertainty?

A. Yes. Gulf experiences demand uncertainty in both the short run and the long run. The Company experiences short-run demand uncertainty as a result of economic cycles, such as times of economic uncertainty, when fewer homes are built, fewer new businesses are started, and factories are running at less than full capacity; and as a result of weather patterns, such as unusually warm winters and cool summers. Gulf experiences long-run demand uncertainty when it invests in major long-lived plant additions or replacements that are expected to remain in service over the next thirty or forty years.

Q. Why are an electric utility's operating expenses uncertain?

A. Operating expense uncertainty arises as a result of factors such as: (1) high volatility in fuel prices or interruptions in fuel supply; (2) variability in maintenance costs and the costs of materials; (3) uncertainty over outages of the company's generation, transmission, and distribution systems, as well as storm-related expenses; (4) uncertainty regarding the cost of purchased power and the revenues achieved from off-system sales; (5) the prospect of increasing employee health care and pension expenses; and (6) the prospect of increased expenses for security.

Q. Does Gulf experience operating expense uncertainty?

A. Yes. Gulf experiences typical operating expense uncertainty associated with its existing operations. However, volatility in fuel prices is partially mitigated by the existence of a fuel adjustment clause in Florida.

Q. Why are utility investment costs uncertain?

A. The electric utility business requires large investments in the plant and equipment required to deliver electricity to customers. The future amounts of required investments in plant and equipment are uncertain as a result of: (1) demand uncertainty; (2) the changing economics of alternative generation technologies; (3) uncertainty in environmental regulations and clean air requirements; (4) uncertainty in the costs of construction materials and labor; and (5) uncertainty in the amount of additional investments to ensure the reliability of the company's transmission and distribution networks. Furthermore, the risk of investing in electric utility facilities is increased by the irreversible nature of the company's investments in utility plant and equipment. For example, if an electric utility decides to invest in new distribution plant to serve a new neighborhood, and, as a result of a changing economy, fewer housing units are built in the neighborhood, the company may not be able to earn a fair return on equity, including both a return of and a return on capital.

Q. You note above that high operating leverage contributes to the business risk of electric utilities. What is operating leverage?

A. Operating leverage is the increased sensitivity of a company's earnings to sales variability that arises when some of the company's costs are fixed.

Q. How do economists measure operating leverage?

A. Economists typically measure operating leverage by the ratio of a company's fixed expenses to its operating margin (revenues minus variable expenses).

Q. What is the difference between fixed and variable expenses?

A. Fixed expenses are expenses that do not vary with output (that is, kilowatt hours sold), and variable expenses are expenses that vary directly with output. For electric utilities, fixed expenses include the capacity component of purchased power costs, the fixed component of operating and maintenance costs, depreciation and amortization, and taxes. Fuel expenses, including fuel transportation, are the primary variable cost for electric utilities. For utilities with large renewable energy generation portfolios, the variability in wind or solar energy production and the limited term of production tax credits is an additional variable cost.

Q. Do electric utilities experience high operating leverage?

A. Yes. As noted above, operating leverage increases when a firm's commitment to fixed costs rises in relation to its operating margin on sales. The relatively high degree of fixed costs in the electric utility business arises primarily from: (1) the average electric utility's large investment in fixed plant and equipment; and (2) the relatively fixed nature of an electric utility's operating and maintenance costs. High operating leverage causes the average electric utility's operating income to be highly sensitive to demand and revenue fluctuations.

Q. Can an electric utility reduce its operating leverage by purchasing, rather than generating, electricity?

A. No. Electric utilities generally purchase power under long-term contracts that include both a fixed capacity charge and a variable charge that depends on the amount of electricity purchased. Since the fixed capacity charge is designed to recover the seller's fixed costs of generating electricity, electric utilities generally experience the same degree of operating leverage when they purchase power as when they generate power.

Q. How does operating leverage affect a company's business risk?

A. Operating leverage affects a company's business risk through its impact on the variability of the company's profits or income. Generally speaking, the higher a company's operating leverage, the higher is the variability of the company's operating profits.

Q. Does regulation create uncertainty for electric utilities?

A. Yes. Investors' perceptions of the business and financial risks of electric utilities are strongly influenced by their views of the quality of regulation.

Investors are aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric utilities operating in those jurisdictions. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Q. You note that financial leverage increases the risk of investing in electric utilities such as Gulf. How do economists measure financial leverage?

A. Economists generally measure financial leverage by the percentages of debt and equity in a company's market value capital structure. Companies with a high percentage of debt compared to equity are considered to have high financial leverage.

Q. Why does financial leverage affect the risk of investing in an electric utility's stock?

A. High debt leverage is a source of additional risk to utility stock investors because it increases the percentage of the firm's costs that are fixed, and the presence of higher fixed costs increases the variability of the equity investors' return on investment.

Q. Can the risks facing electric utilities such as Gulf be distinguished from the risks of investing in companies in other industries?

A. Yes. The risks of investing in electric utilities such as Gulf can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risk of investing in electric utilities is increased because of the high capital intensity of the electric energy business and the general irreversibility of investments in energy facilities once the investments have been made. Second, unlike returns in competitive industries, the returns from investment in electric utilities such as Gulf are largely asymmetric. That is, there is little opportunity for the utility to earn more than its required return, but a significant chance that the utility will earn less than its required return.

V. COST OF EQUITY ESTIMATION METHODS

Q. What methods do you use to estimate Gulf's cost of equity?

A. I use several generally accepted methods for estimating the cost of equity for Gulf. These are the DCF, the ex ante risk premium, the ex post risk premium, and the CAPM. The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The ex ante risk premium method assumes that an investor's expectations regarding the equity risk premium can be estimated from data on the DCF expected rate of return on equity compared to the interest rate on long-term bonds. The ex post risk premium method assumes that an investor's expectations regarding the equity-debt return differential are influenced by the historical record of comparable returns on stock and bond investments. The cost of equity under both risk premium methods is then equal to the expected interest rate on bond investments plus the expected risk premium. The CAPM assumes that the investor's required rate of return on equity is equal to an expected risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

A. DISCOUNTED CASH FLOW METHOD

Q. Please describe the DCF model.

A. The DCF model is based on the assumption that investors value an asset because they expect to receive a sequence of cash flows from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = C/(1+i) + C/(1+i)^2 + \cdots + (C+F)/(1+i)^n$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;
i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_S = D_1/(1+k) + D_2/(1+k)^2 + \cdots + (D_n + P_n)/(1+k)^n$$

where:

P_S	=	Current price of the firm's stock;
$D_1, D_2 \ldots D_n$	=	Expected annual dividend per share on the firm's stock;
P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation 2 is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, *g*, this equation can be solved for *k*, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and *g* is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the expected dividend yield component of the annual DCF model, and the term *g* is called the expected growth component of the annual DCF model.

Q. Are you recommending that the annual DCF model be used to estimate Gulf's cost of equity?

A. No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression of the present value of future dividends if dividends are paid annually at the end of each year. Because the companies in my comparable group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model should be used to estimate the cost of equity for these firms. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present value of a quarterly stream of dividend payments. A complete analysis of the implications of the quarterly payment of dividends on the DCF model is provided in Exhibit JVW-2, Appendix 2. For the reasons cited there, I employed the quarterly DCF model throughout my calculations, even though the results of the quarterly DCF model for my companies are approximately equal to the results of a properly applied annual DCF model (in which the end-of-year dividend is estimated by multiplying the current annual dividend by the factor one plus the growth rate).

Q. Please describe the quarterly DCF model you use.

A. The quarterly DCF model I use is described on Exhibit JVW-1, Schedule 1 and in Exhibit JVW-2, Appendix 2. The quarterly DCF equation shows that the cost of equity is: the sum of the future expected dividend yield and the growth rate, where the dividend in the dividend yield is the equivalent future value of the four quarterly dividends at the end of the year, and the growth rate is the expected growth in dividends or earnings per share.

Q. How do you estimate the quarterly dividend payments in your quarterly DCF model?

A. The quarterly DCF model requires an estimate of the dividends, d_1, d_2, d_3, and d_4, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by the factor, *(1 + the growth rate, g)*.

Q. Can you illustrate how you estimate the next four quarterly dividends with data for a specific company?

A. Yes. In the case of ALLETE, the first company shown in Exhibit JVW- 1, Schedule 1, the last four quarterly dividends are equal to 0.505, 0.505, 0.505, and 0.520. Thus dividends d_1, d_2, and d_3 are equal to 0.535 [.505 x (1 + .06) = 0.535] and d_4 is equal to 0.551 [0.52 x (1 + .06) = 0.551]. (As noted previously, the logic underlying this procedure is described in Exhibit JVW-2, Appendix 2.)

Q. How do you estimate the growth component of the quarterly DCF model?

A. I use the analysts' estimates of future earnings per share (EPS) growth reported by I/B/E/S Thomson Reuters.

Q. What are the analysts' estimates of future EPS growth?

A. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent three- to five-year forecasts of EPS growth.

Q. What is I/B/E/S?

A. I/B/E/S is a division of Thomson Reuters that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as an estimate of future firm performance.

Q. Why do you use the I/B/E/S growth estimates?

A. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q. Why do you rely on analysts' projections of future EPS growth in estimating the investors' expected growth rate rather than looking at past historical growth rates?

A. I rely on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth.

Q. Have you performed any studies concerning the use of analysts' forecasts as an estimate of investors' expected growth rate, g?

A. Yes. I prepared a study with Willard T. Carleton, Professor Emeritus of Finance at the University of Arizona, which is described in a paper entitled "Investor Growth Expectations and Stock Prices: Analysts vs. History," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

Q. Please summarize the results of your study.

A. We performed a correlation analysis to identify the historically oriented growth rates which best described a firm's stock price. We then performed a regression study comparing the historical growth rates and retention growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth and retention growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations* *and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making decisions to buy and sell stock. The results provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. I note that researchers at State Street Financial Advisors updated my study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Q. What price do you use in your DCF model?

A. I use a simple average of the monthly high and low stock prices for each firm for the three-month period ending March 2016. These high and low stock prices were obtained from Thomson Reuters.

Q. Why do you use the three-month average stock price in applying the DCF method?

A. I use the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

Q. Do you include an allowance for flotation costs in your DCF analysis?

A. Yes. I include a five percent allowance for flotation costs in my DCF calculations. A complete explanation of the need for flotation costs is contained in Exhibit JVW-2, Appendix 3.

Q. Please explain your inclusion of flotation costs.

A. All firms that have sold securities in the capital markets have incurred some level of flotation costs, including the costs of underwriters' commissions, legal fees, and printing expense, for example. These costs are withheld from the proceeds of the stock sale or are paid separately, and must be recovered over the life of the equity issue. Costs vary depending upon the size of the issue, the type of registration method used and other factors, but in general these costs range between three and five percent of the proceeds from the issue [see Inmoo Lee, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Vol. XIX No 1 (Spring 1996), 59-74, and Clifford W. Smith, "Alternative Methods for Raising Capital," *Journal of Financial Economics* 5 (1977) 273-307]. In addition to these costs, for large equity issues (in relation to outstanding equity shares), there is likely to be a decline in price associated with the sale of shares to the public. On average, the decline in price associated with new stock issuances has been estimated at two to three percent (see Richard H. Pettway, "The Effects of New Equity Sales upon Utility Share Prices," *Public Utilities Fortnightly*, May 10, 1984, 35—39). Thus, the total flotation cost, including both issuance expense and stock price decline, generally ranges from five to eight percent of the proceeds of an equity issue. I believe a combined five percent allowance for flotation costs is a conservative estimate that should be used in applying the DCF model in this proceeding (see Exhibit JVW-1, Schedule 1).

Q. How do you apply the DCF approach to estimate the required return on equity for Gulf?
A. I apply the DCF approach to the Value Line electric utilities shown in Exhibit JVW-1, Schedule 1.

Q. How do you select your electric utility company group?
A. I select all the electric utilities followed by Value Line that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have an available positive I/B/E/S long-term growth forecast; (4) have an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3; and (5) are not the subject of a merger offer that has not been completed.

Q. Why do you eliminate companies that have either decreased or eliminated their dividend in the past two years?
A. The DCF model requires the assumption that dividends will grow at a constant rate into the indefinite future. If a company has either decreased or eliminated its dividend in recent years, an assumption that the company's dividend will grow at the same rate into the indefinite future is questionable.

Q. Why do you eliminate companies that are the subject of a merger offer that has not been completed?

A. A merger announcement can sometimes have a significant impact on a company's stock price because of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q. Please summarize the results of your application of the DCF model to your company group.

A. As shown on JVW-1, Schedule 1, I obtain an average DCF result of 9.7 percent for my electric utility group.

B. RISK PREMIUM METHOD

Q. Please describe the risk premium method of estimating the cost of equity.

A. The risk premium method is based on the principle that investors expect to earn a return on an equity investment that reflects a "premium" above the interest rate they expect to earn on an investment in bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q. Does the risk premium approach specify what debt instrument should be used to estimate the interest rate component in the methodology?

A. No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks to the interest rate on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q. Does the risk premium approach require that the same companies be used to estimate the stock return as are used to estimate the bond return?

A. No. For example, many analysts apply the risk premium approach by comparing the return on a portfolio of stocks to the income return on Treasury securities such as long-term Treasury bonds. Clearly, in this widely accepted application of the risk premium approach, the same companies are not used to estimate the stock return as are used to estimate the bond return, since the United States government is not a company.

Q. How do you measure the required risk premium on an equity investment in your group of publicly-traded electric utilities?

A. I use two methods to estimate the required risk premium on an equity investment in publicly-traded electric utilities. The first is called the ex ante risk premium method and the second is called the ex post risk premium method.

1. Ex Ante Risk Premium Method

Q. Please describe your ex ante risk premium approach for measuring the required risk premium on an equity investment in electric utilities.

A. My ex ante risk premium method is based on studies of the DCF expected return on a group of electric utilities compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculated the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY} = the required risk premium on an equity investment in the proxy group of companies,

DCF_{PROXY} = average DCF estimated cost of equity on a portfolio of proxy companies; and

I_A = the yield to maturity on an investment in A-rated utility bonds.

I then perform regression analyses to determine if there is a relationship between the calculated risk premium and interest rates. A detailed description of my ex ante risk premium studies is contained in Exhibit

JVW-2, Appendix 4, and the underlying DCF results and interest rates are displayed in Exhibit JVW-1, Schedule 2.

Q. From your regression analyses, do you find that there is a relationship between the calculated equity risk premium and interest rates?

A. Yes. My regression analyses confirm that there is an inverse relationship between the calculated equity risk premium and interest rates. Specifically, my analyses indicate that when the yield to maturity on A-rated utility bonds declines by 100 basis points, the required equity risk premium increases by 60 basis points; and when the yield on A-rated utility bonds increases by 100 basis points, the required equity risk premium declines by 60 basis points (*see* Appendix 4, p. 3).

Q. How do you use the regression analyses to estimate the cost of equity in your ex ante risk premium method?

A. To estimate the cost of equity, I add the estimated 4.7 percent required equity risk premium obtained from my regression analyses to the forecasted interest rate on A-rated utility bonds.

Q. What cost of equity estimate do you obtain using your ex ante risk premium method?

A. I obtain a cost of equity estimate of 10.9 percent using my ex ante risk premium method. This cost of equity estimate is the sum of the estimated 4.7 percent equity risk premium from my regression analyses and the 6.2 percent forecasted yield to maturity on A-rated utility bonds.

Q. How do you obtain the expected yield on A-rated utility bonds?

A. I obtain the expected yield to maturity on A-rated utility bonds, 6.2 percent, by averaging forecast data from Value Line and the U.S. Energy Information Administration (EIA). Value Line Selection & Opinion (March 4, 2016) projects a Aaa-rated Corporate bond yield equal to 5.6 percent. The March 2016 average spread between A-rated utility bonds and Aaa-rated Corporate bonds is 34 basis points (A-rated utility, 4.16 percent, less Aaa-rated Corporate, 3.82 percent, equals 34 basis points). Adding 34 basis points to the 5.6 percent Value Line Aaa Corporate bond forecast equals a forecast yield of 5.94 percent for the A-rated utility bonds. The EIA forecasts an AA-rated utility bond yield equal to 6.21 percent. The average spread between AA-rated utility and A-rated utility bonds at March 2016 is 23 basis points (4.16 percent less 3.93 percent). Adding 23 basis points to EIA's 6.21 percent AA-utility bond yield forecast equals a forecast yield for A-rated utility bonds equal to 6.44 percent. The average of the forecasts (5.9 percent using Value Line data and 6.44 percent using EIA data) is 6.2 percent.

Q. Why do you use a forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity?

A. I use a forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. Because current interest rates are depressed as a result of the

Federal Reserve's efforts to stimulate the economy by keeping interest rates low, current interest rates at this time are likely a poor indicator of expected future interest rates. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

2. Ex Post Risk Premium Method

Q. Please describe your ex post risk premium method for measuring the required risk premium on an equity investment in electric utilities.

A. I first perform a study of the comparable returns received by bond and stock investors over the 79 years of my study. I estimate the returns on stock and bond portfolios, using stock price and dividend yield data on the S&P 500 and bond yield data on Moody's A-rated Utility Bonds. My study consists of making an investment of one dollar in the S&P 500 and Moody's A-rated utility bonds at the beginning of 1937, and reinvesting the principal plus return each year to 2016. The return associated with each stock portfolio is the sum of the annual dividend yield and capital gain (or loss) which accrued to this portfolio during the year(s) in which it was held. The return associated with the bond portfolio, on the other hand, is the sum of the annual coupon yield and capital gain (or loss) which accrued to the bond portfolio during the year(s) in which it was held. The resulting annual returns on the stock and bond portfolios purchased in each year from 1937 to 2016 are shown on Exhibit JVW-1, Schedule 3. The average annual return on an investment in the S&P 500 stock portfolio is 11.1 percent, while the average annual return on an investment in the Moody's A-rated utility bond portfolio is 6.6 percent. The risk premium on the S&P 500 stock portfolio is, therefore, 4.5 percent.

I also conduct a second study using stock data on the S&P Utilities rather than the S&P 500. As shown on Exhibit JVW-1, Schedule 4, the average annual return on an investment in the S&P Utility stock portfolio is 10.5 percent per year. Thus, the return on the S&P Utility stock portfolio exceeded the return on the Moody's A-rated utility bond portfolio by 3.9 percent (10.5 – 6.6 = 3.9).

Q. Why is it appropriate to perform your ex post risk premium analysis using both the S&P 500 and the S&P Utilities stock indices?

A. I perform my ex post risk premium analysis on both the S&P 500 and the S&P Utilities because I believe electric utilities today face risks that are somewhere in between the average risk of the S&P Utilities and the S&P 500 over the years 1937 to 2016. Thus, I use the average of the two historically-based risk premiums as my estimate of the required risk premium in my ex post risk premium method.

Q. Would your study provide a different risk premium if you started with a different time period?

A. Yes. The risk premium results vary somewhat depending on the historical time period chosen. My policy is to go back as far in history as I can get reliable data. I thought it would be most meaningful to begin after the passage and implementation of the Public Utility Holding Company Act of 1935 (the 1935 Act). This Act significantly changed the structure of the public utility industry. Because the 1935 Act was not implemented until the beginning of 1937, I concluded that data prior to 1937 should not be used in my study. (The repeal of the 1935 Act has not materially impacted the structure of the public utility industry; thus, the Act's repeal does not have any impact on my choice of time period.)

Q. Why is it necessary to examine the yield from debt investments in order to determine the investors' required rate of return on equity capital?

A. As previously explained, investors expect to earn a return on their equity investment that exceeds currently available bond yields because the return on equity, as a residual return, is less certain than the yield on bonds; and investors must be compensated for this uncertainty. Investors' expectations concerning the amount by which the return on equity will exceed the bond yield may be influenced by historical differences in returns to bond and stock investors. Thus, we can estimate investors' expected returns from an equity investment based on information about past differences between returns on stocks and bonds. In interpreting this information, investors would also recognize that risk premiums increase when interest rates are low.

Q. What conclusions do you draw from your ex post risk premium analyses about the required return on an equity investment in electric utilities?

A. My studies provide strong evidence that investors today require an equity return of at least 3.9 to 4.5 percentage points above the expected yield on A-rated utility bonds. As discussed above, the forecast yield on A-rated utility bonds is 6.2 percent. Adding a 3.9 to 4.5 percentage point risk premium to a yield of 6.2 percent on A-rated utility bonds, I obtain an expected return on equity in the range 10.1 percent to 10.7 percent, with a midpoint of 10.4 percent. Adding a twenty-basis-point allowance for flotation costs, I obtain an estimate of 10.6 percent as the ex post risk premium cost of equity. (I determine the flotation cost allowance by calculating the difference in my DCF results with and without a flotation cost allowance.)

C. CAPITAL ASSET PRICING MODEL

Q. What is the CAPM?

A. The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + (Equity beta x Market risk premium)

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q. How do you use the CAPM to estimate the cost of equity for your proxy companies?

A. The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use a forecasted yield to maturity on 20-year Treasury bonds of 4.2 percent, obtained using data from Value Line and EIA. For my estimate of the company-specific risk, or beta, I use both the current average 0.75 Value Line beta for my group of electric utilities and the 0.90 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio. For my estimate of the expected risk premium on the market portfolio, I use two approaches. First, I estimate the risk premium on the market portfolio using historical risk premium data reported in the *2016 Valuation Handbook* for the years 1926 through 2015, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. How do you obtain the forecasted yield to maturity on 20-year Treasury bonds?

A. As noted above, I use data from Value Line and EIA to obtain a forecasted yield to maturity on 20-year Treasury bonds. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread between the average March 2016 yield on 10-year Treasury notes (1.89 percent) and 20-year Treasury bonds (2.28 percent) is 39 basis points. Adding 39 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.89 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, March 4, 2016). EIA forecasts a yield of 4.11 percent on 10-year Treasury notes. Adding the 39 basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.11 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 4.5 percent. The average of the forecasts is 4.2 percent (3.89 percent using Value Line data and 4.5 percent using EIA data).

1. Historical CAPM

Q. How do you estimate the expected risk premium on the market portfolio using historical risk premium data developed by Ibbotson® SBBI®?

A. I estimate the expected risk premium on the market portfolio by calculating the difference between the arithmetic mean total return on the S&P 500 from 1926 to 2016 (12.0 percent) and the average income return on 20-year U.S. Treasury bonds over the same period (5.1 percent). Thus, my historical risk premium method produces a risk premium of 6.9 percent (12.0 – 5.1 = 6.9).

Q. Why do you recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500?

A. I recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500 because, in my opinion, the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future. For an investment which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future. A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in Exhibit JVW-1, Schedule 5.

Q. Why do you recommend that the risk premium on the market portfolio be measured using the income return on 20-year Treasury bonds rather than the total return on these bonds?

A. As discussed above, the CAPM requires an estimate of the risk-free rate of interest. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free.

Q. What CAPM result do you obtain when you estimate the expected risk premium on the market portfolio from the arithmetic mean difference between the return on the market and the yield on 20-year Treasury bonds?

A. Using a risk-free rate equal to 4.2 percent, an electric utility beta equal to 0.75, a risk premium on the market portfolio equal to 6.9 percent, and a flotation cost allowance equal to twenty basis points, I obtain an historical CAPM estimate of the cost of equity equal to 9.6 percent for my electric utility group (4.2 + 0.75 x 6.9 + 0.20= 9.6) (see Exhibit JVW-1, Schedule 6).

Q. Is there any evidence from the finance literature that the application of the historical CAPM may underestimate the cost of equity?

A. Yes. There is substantial evidence that: (1) the historical CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0; and (2) the CAPM is less reliable the further the estimated beta is from 1.0.

Q. What is the evidence that the CAPM tends to underestimate the cost of equity for companies with betas less than 1.0 and is less reliable the further the estimated beta is from 1.0?

A. The original evidence that the unadjusted CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and is less reliable the further the estimated beta is from 1.0 was presented in a paper by Black, Jensen, and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the

Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy (1979), Banz (1981), Fama and French (1992), Fama and French (2004), Fama and MacBeth (1973), and Jegadeesh and Titman (1993).

Q. Can you briefly summarize these articles?

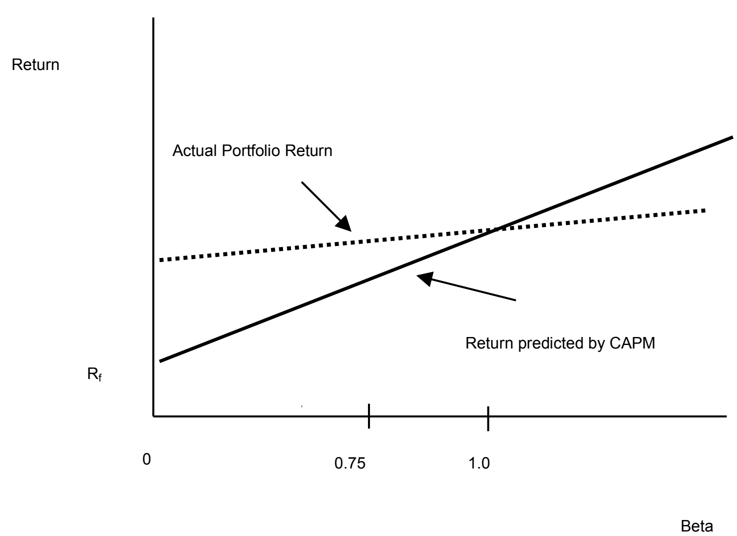
A. Yes. The CAPM conjectures that security returns increase with increases in security betas in line with the equation:

$$ER_i = R_f + \beta_i \left\lfloor ER_m - R_f \right\rfloor,$$

where ER_i is the expected return on security or portfolio *i*, R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and β_i is a measure of the risk of investing in security or portfolio *i* (see FIGURE 1 below).

FIGURE 1

AVERAGE RETURNS COMPARED TO BETA



Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that the relationship between returns and betas is inconsistent with the relationship posited by the CAPM. As described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 1 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 1 than the solid line, they generally agree that the dotted line lies above the solid line for portfolios with betas less than 1.0 and below the solid line for portfolios with betas greater than 1.0. Thus, in practice, scholars generally agree that the CAPM underestimates portfolio returns for companies with betas less than 1.0, and overestimates portfolio returns for portfolios with betas greater than 1.0.

Q. Do you have additional evidence that the CAPM tends to underestimate the cost of equity for utilities with average betas less than 1.0?

A. Yes. As shown in Exhibit JVW-1, Schedule 7, over the period 1937 to 2016, investors in the S&P Utilities Stock Index have earned a risk premium over the yield on long-term Treasury bonds equal to 5.34 percent, while investors in the S&P 500 have earned a risk premium over the yield on long-term Treasury bonds equal to 5.92 percent. According to the CAPM, investors in utility stocks should expect to earn a risk premium over the yield on long-term Treasury securities equal to the average utility beta times the expected risk premium on the S&P 500. Thus, the ratio of the risk premium on the utility portfolio to the risk premium on the S&P 500 should equal the utility beta. However, the average utility beta at the time of my studies is approximately 0.75, whereas the historical ratio of the utility risk premium to the S&P 500 risk premium is 0.90 (5.34 ÷ 5.92 = 0.90). In short, the current 0.75 measured beta for electric utilities underestimates the cost of equity for electric utilities, providing further support for the conclusion that the CAPM underestimates the cost of equity for electric utilities at this time.

Q. Can you adjust for the tendency of the CAPM to underestimate the cost of equity for companies with betas less than 1.0?

A. Yes. I can implement the CAPM using the 0.90 beta I discuss above, which I obtain by comparing the historical returns on utilities to historical returns on the S&P 500.

Q. What CAPM result do you obtain when you use a beta equal to 0.90 rather than an electric utility beta equal to 0.75?

A. I obtain a CAPM result equal to 10.6 percent using a risk free rate equal to 4.2 percent, a beta equal to 0.90, the historical market risk premium equal to 6.9 percent, and a flotation cost allowance of 20 basis points (4.2 + 0.90 x 6.9+ 0.20= 10.6). (See Exhibit JVW-1, Schedule 8.)

Q. What is the average of your two historical CAPM results?

A. The average of my two historical CAPM results is 10.1 percent (9.6 percent + 10.6 percent) ÷ 2 = 10.1 percent). I use 10.1 percent as my estimate of the historical CAPM cost of equity.

2. DCF-Based CAPM

Q. How does your DCF-Based CAPM differ from your historical CAPM?

A. As noted above, my DCF-based CAPM differs from my historical CAPM only in the method I use to estimate the risk premium on the market portfolio. In the historical CAPM, I use historical risk premium data to estimate the risk premium on the market portfolio. In the DCF-based CAPM, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. What risk premium do you obtain when you calculate the difference between the DCF-return on the S&P 500 and the risk-free rate?

A. Using this method, I obtain a risk premium on the market portfolio equal to 7.7 percent (This value is obtained by subtracting the forecasted risk-free rate, 4.2 percent, from the DCF estimate of the market return, 11.9 percent (11.9 – 4.2 = 7.7). (See Exhibit JVW-1, Schedule 9.)

Q. What CAPM result do you obtain when you estimate the expected return on the market portfolio by applying the DCF model to the S&P 500?

A. Using a risk-free rate of 4.2 percent, an electric utility beta of 0.75, a risk premium on the market portfolio of 7.7 percent, and a flotation cost allowance equal to twenty basis points, I obtain a CAPM result of 10.2 percent for my electric utility group. Using a risk-free rate of 4.2 percent, an electric utility beta of 0.90, a risk premium on the market portfolio of 7.7 percent, and a flotation cost allowance of twenty basis points, I obtain a CAPM result of 11.4 percent for my electric utility group. The average of these two results is 10.8 percent (10.2 percent + 11.4 percent) ÷ 2 = 10.8 percent). I use 10.8 percent as my estimate of the DCF-based CAPM cost of equity.

VI. CONCLUSION REGARDING THE FAIR RATE OF RETURN ON EQUITY

Q. What is the fair rate of return on equity?

A. The fair rate of return on equity is a forward-looking return on equity that provides the regulated company with an opportunity to earn a return on its investment over the period in which rates are in effect that is commensurate with returns that investors expect to earn on other investments of similar risk, as I discuss above. Because the fair rate of return is a forward-looking return, the estimate of the fair return requires consideration of investors' expectations for a reasonably long period into the future.

Q. Based on your application of several cost of equity methods to your proxy company groups, what is your conclusion regarding the fair rate of return on equity for your comparable companies?

A. Based on my application of several cost of equity methods, I conclude that the fair rate of return on equity for my comparable companies is in the range 9.7 percent to 10.9 percent, with an average equal to 10.4 percent (see TABLE 1 below).

TABLE 1

COST OF EQUITY MODEL RESULTS

Model	Model Result
Discounted Cash Flow	9.7%
Ex Ante Risk Premium	10.9%
Ex Post Risk Premium	10.6%
CAPM – Historical	10.1%
CAPM - DCF Based	10.8%
Average	10.4%

Q. Does your 10.4 percent fair rate of return on equity conclusion for your proxy companies depend on the percentages of debt and equity in the proxy companies' average capital structure?

A. Yes. My 10.4 percent fair rate of return on equity conclusion reflects the financial risk associated with the average market value capital structure of my proxy companies, which has approximately 65 percent equity. Because market conditions are at historically high levels, I have also examined the average market value capital structure of the Value Line electric utilities over the last ten years; and, as noted above, I find that the average market value capital structure of the Value Line electric utilities contains approximately 60 percent equity.

Q. What capital structure is Gulf recommending in this proceeding for the purpose of ratemaking?

A. Gulf is recommending that a capital structure containing 40.77 percent long-term debt, 5.27 percent preferred stock, and 53.96 percent common equity be used for rate making purposes in this proceeding.

Q. How does the financial risk reflected in Gulf's recommended rate making capital structure in this proceeding compare to the financial risk reflected in the cost of equity estimates for your proxy companies?

A. Although Gulf's recommended capital structure contains an appropriate mix of debt and equity and is a reasonable capital structure for rate making purposes in this proceeding, this recommended rate making capital structure embodies greater financial risk than is reflected in my cost of equity estimates from my proxy companies.

Q. You discuss above that the cost of equity depends on a company's capital structure. Is there a way to adjust the 10.4 percent cost of equity for your proxy companies to reflect the higher financial risk of Gulf's rate making capital structure in this proceeding?

A. Yes. Because my proxy groups are similar in business risk to Gulf, Gulf should have the same weighted average cost of capital as my proxy companies. One may easily determine the cost of equity Gulf would need in order to have the same weighted average cost of capital as my proxy companies.

Q. Do you perform such a calculation?

A. Yes. I adjust the 10.4 percent average cost of equity for my proxy groups by recognizing that to attract capital, Gulf must have the same weighted average cost of capital as my proxy group. My analysis, which is shown on Exhibit JVW-1, Schedule 10, indicates that Gulf would require a fair rate of return on equity equal to 11.0 percent in order to have the same weighted average cost of capital as my proxy companies.

Q. What return on common equity do you recommend for Gulf?

A. I recommend a return on common equity equal 11.0 percent for Gulf. My recommendation is conservative in that it does not reflect the higher average percentage of equity in the market value capital structure of my proxy companies in today's market environment compared to the average market value of equity in the capital structure of the Value Line electric utilities over the last ten years.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

GULF POWER COMPANY

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

I. POSITION, QUALIFICATIONS, AND PURPOSE

Q. Please state your name and business address.

A. My name is Dane Watson. My business address is 1410 Avenue K, Suite 1105B, Plano, TX 75074.

Q. What is your position?

A. I am the Managing Partner in Alliance Consulting Group (Alliance).

Q. What are your responsibilities as Managing Partner?

A. As the Managing Partner of Alliance, I am responsible for performing and defending depreciation studies for clients across the United States in a variety of regulatory proceedings. My duties include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management, and supporting such rates before regulatory bodies. I have performed more than 150 depreciation studies in my career, appeared in more than 125 cases, and testified before 30 regulatory bodies as an expert witness on the subject of depreciation.

Q. Please state your prior work experience and responsibilities.

A. Since graduating from college in 1985, I have worked in the areas of depreciation and valuation. I founded Alliance in 2004, and I am responsible for conducting depreciation, valuation, and certain other accounting-related studies for utilities in various regulated industries.

My prior employment from 1985 to 2004 was with Texas Utilities and successor companies (TXU). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, in addition to my depreciation responsibilities, I also served as Manager of Property Accounting Services and Records Management.

Q. What is your educational background?

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University. I am a registered Professional Engineer in the State of Texas.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals (the Society) has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I met all requirements and have become a Certified Depreciation Professional (CDP).

Q. Please describe your other professional activities.

A. I have twice been Chair of the Edison Electric Institute (EEI) Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE) and have held numerous offices on the Executive Board of the Dallas Section of IEEE as well as National and Worldwide offices. I have served as President of the Society of Depreciation Professionals twice, most recently in 2015.

Q. Have you previously testified before state and/or federal regulatory commissions?

A. Yes. I have testified before numerous state and federal agencies in my 30 year career in performing depreciation studies. I have conducted depreciation studies, filed written testimony, and/or testified before the commissions identified in Exhibit DAW-3.

Q. What was your responsibility and participation in the conduct of the Depreciation Rate Study (the Study) filed on July 14, 2016, and corrected on September 20, 2016, for Gulf Power Company (Gulf or the Company)?

A. I was personally responsible for, participated in, and directed all aspects of the work performed by Alliance resulting in the recommendations contained in Exhibit DAW-1.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to: (1) discuss the recent depreciation study conducted for Gulf's electric depreciable assets based on plant and reserve balances as of December 31, 2016; and (2) support and justify the recommended depreciation rates for the Company's assets.

Q. Are you sponsoring any exhibits?

A. Yes. I sponsor Exhibits DAW-1, DAW-2, and DAW-3. To the best of my knowledge, the information contained in these exhibits is true and correct.

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

A. No. However, the proposed depreciation rates will be incorporated in the MFR schedules submitted by Gulf.

II. TESTIMONY STRUCTURE, DEPRECIATION DEFINITION AND STUDY PURPOSE

Q. How is your direct testimony structured?

A. My direct testimony is structured as follows:

In Section III, I explain the property included in the Study; the four-phase approach I used to conduct the Study; and the depreciation system I used for the Study.

In Section IV, I explain how depreciation rates are determined, including identifying the formula for depreciation rates. This portion of my direct testimony also explains and fully discusses each portion of the depreciation rate formula that is supported by my Study. Section IV is broken into the following subparts, which align with the components of the depreciation rate formula that the Study supports: (A) Depreciation Rate Formula; (B) Theoretical Reserve; (C) Net Salvage Amounts and Percentages; (D) Remaining Life Analysis; and (E) Depreciation Rates and Depreciation Accrual Rates.

In Section V, I discuss the change in depreciation expense as a result of the proposed depreciation rates. Specifically, I explain why Gulf's depreciation expense is increasing.

Q. What definition of depreciation have you used for the purposes of conducting a depreciation study and preparing your direct testimony?

A. The term "depreciation," as used herein, is considered in the accounting sense–that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. In other words, depreciation expense allocates the cost of the asset, including any estimated net salvage (the negative of this is also known as net removal) necessary to remove the asset, as an ongoing cost of operations over the economic life of the asset. However, the amount allocated to any one accounting period does not necessarily represent an actual loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Q. Please generally describe the purpose of the Study.

A. The key functions of the Study are to: (1) determine the average service lives for Transmission, Distribution, and General Plant; (2) obtain terminal retirement dates and determine the interim retirement ratios for Production Plant; (3) determine the interim net salvage amounts for all Production Plant; (4) determine the net salvage percentages for Transmission, Distribution, and General Plant; (5) calculate the theoretical reserve of each property group based on the remaining life of the group, the total life of the group and the estimated net salvage; and (6) develop depreciation rates, including the annual depreciation accrual.

Q. Based on the Study, what conclusions do you reach?

A. I conclude that the depreciation rates developed for Gulf's electric utility accounts as set forth in the Study, which is sponsored by me and included as Exhibit DAW-1, encompass the best and most recent information for calculating Gulf's depreciation expense associated with these assets.

Based on life and net salvage parameters developed and applied to plant assets and depreciation reserve balances as of December 31, 2016, the depreciation rates in the Study will result in an increase in the annual depreciation expense of approximately $20.4 million per year. This amount was determined by comparing the depreciation expense difference between the current depreciation rates and the proposed depreciation rates as of December 31, 2016. A functional summary comparison of depreciation expense is shown in Exhibit DAW-2, Schedule 1, and a more detailed comparison is shown in Appendix B of Exhibit DAW-1.

III. GULF'S ELECTRIC DEPRECIATION RATE STUDY

Q. What is the purpose of this section of your direct testimony?

A. In this section of my direct testimony, I testify to the property included in the Study; the four-phase approach I used to conduct the Study; and the depreciation system (straight-line method, average life group (ALG) procedure, remaining-life technique) used for the Study.

Q. Did the Company give you any specific information for conducting the Study?

A. Yes. The Company gave me the following information for the Study:

a. Terminal retirement dates for generating stations supplied by the Company;

b. Historical data used to determine the interim retirement ratio and interim net salvage analysis for generating stations as of December 31, 2014;

c. Dismantlement costs associated with dismantling each generating unit for the Steam and Other Production functions which will be excluded from the Study since those amounts are determined in a separate study;

d. Historical data to analyze for life and net salvage to assist in making recommendations for Transmission, Distribution, and General Plant assets based on data as of December 31, 2014; and

e. Plant and reserve balances to calculate the theoretical reserves and the recommended whole life and remaining life depreciation rates, including the annual depreciation expense accrual, on forecast plant and reserve balances as of December 31, 2016.

Q. What property is included in the depreciation study?

A. There are five general classes, or functional groups, of depreciable property that are analyzed in the study: (1) Steam Production Plant, (2) Other Production Plant, (3) Transmission Plant, (4) Distribution Plant, and (5) General Plant property. Steam Production assets in accounts 310-316 consist of generating units that use fossil fuels to produce steam to generate electricity. Other Production assets in accounts 340-346 consist of generating units (such as combustion turbines) that use natural gas to directly turn rotors to produce electricity. The Transmission Plant functional group primarily consists of lines and associated facilities used to move power from power plants and outside areas into the distribution system. The Distribution Plant functional group primarily consists of lines and associated facilities used to distribute electricity to customers of Gulf. General Plant property is plant (such as office buildings) used to support Gulf's overall operations.

Q. Please describe your depreciation study approach.

A. With the assistance of my staff, I conducted the Gulf Study in four phases as described at pages 26-28 of Exhibit DAW-1. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the Study, I collected historical data through December 31, 2014 to be used in the analysis. After the data was assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers and managerial personnel, combined with the Study results, was then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans, should be applied. The final phase is calculation of depreciation rates and the theoretical reserve.

The authoritative treatise, *Depreciation Systems*, documents the following stages of a depreciation study: "statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, and document recommendations".[1] My approach mirrors this process, and following this approach ensures that Alliance comprehensively and thoroughly projects the future expectations for the Company's assets. Exhibit DAW-1, page 28 shows Figure 1, which demonstrates the four phases of the Depreciation Rate Study conducted for Gulf.

[1] W.C. Fitch and F.K. Wolf, DEPRECIATION SYSTEMS, at page 289 (Iowa State Press, 1994).

Q. What depreciation system did you use for the study?

A. The straight-line method, the ALG procedure, remaining-life technique depreciation system was used for this Study. This is the same methodology used by Gulf and approved by this Commission for the existing depreciation rates established in Docket No. 090319-EI.

Q. What is a survivor curve?

A. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves, the predominantly used survivor curve method in the utility industry, are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, the Iowa Curves have become a descriptive standard for the life characteristics of industrial property. For more detail on survivor curves see pages 13-16 of Exhibit DAW-1.

Q. How is a survivor curve used in this study?

A. Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average service life and survivor curve. When selecting an average service life, a survivor curve is also selected. When recommending depreciation rates, the depreciation analyst selects the average service life and survivor curve that are used to compute remaining life and theoretical reserve.

IV. DETERMINATION OF THE DEPRECIATION RATES

Q. What is the purpose of this section of your direct testimony?

A. In this section of my direct testimony, I explain how depreciation rates are determined, including identifying the formula for depreciation rates. This portion of my direct testimony also explains and fully discusses each portion of the depreciation rate formula that is supported by my Study. Section IV is broken into the following subparts, which aligns with the components of the depreciation rate formula that the Study supports: (A) The Depreciation Rate Formula; (B) Theoretical Reserve; (C) Net Salvage Amounts or Percentages; (D) Remaining Life Analysis; and (E) Depreciation Rates and Depreciation Accrual Rates.

A. THE DEPRECIATION RATE FORMULA

Q. How are the depreciation rates determined?

A. The formula used to derive depreciation rates calculates annual depreciation accrual amounts for each group by dividing the original cost of the asset (gross plant), less book depreciation reserve, less estimated net salvage, by the group's respective remaining life. The resulting annual accrual amounts for all depreciable property within an account are accumulated, and the total is divided by the original cost (gross plant) of all depreciable property within the account to determine the depreciation rate.

Q. What portion of the formula used to derive depreciation rates is supported by the depreciation rate study?

A. The Depreciation Rate Study determines several pieces of the overall formula used to derive depreciation rates. The portions of the formula derived by the Study are:

- Depreciation Reserve Balance: The depreciation reserve was provided by the Company with the projected gross plant balance amounts and the projected depreciation reserve as of December 31, 2016. The Study depreciation reserve balance is subtracted from gross plant.
- Net Salvage Amounts or Percentages: The Study supports the overall net salvage percentages. The Study calculates and recommends the net salvage percentages for the Production functions (interim net salvage only), Transmission, Distribution, and General Plant accounts. For these plant accounts, salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal, as supported by the Study, by the original installed cost of the retired asset.
- Remaining Life: The Study supports the remaining life calculation by determining the appropriate average service lives and retirement survivor curve for each account within a functional group.
- Resulting Annual Depreciation Accrual and Depreciation Rates: As discussed above, the Study calculates the depreciation rates and the annual accrual amounts are then derived from these rates. The computation of the annual depreciation rates and annual accrual amounts is shown in Appendix A of Exhibit DAW-1.

I describe in more depth below how the Study determines each component of the formula, as well as the Study results for each component.

B. THEORETICAL RESERVE

Q. What purpose does the theoretical reserve serve in a depreciation study?

A. The theoretical reserve represents the portion of a property group's cost that would have been accrued as depreciation reserve if current life and net salvage expectations were used throughout the life of the property group for depreciation accruals. The theoretical reserve for the asset group serves as a point of comparison to the book reserve to determine if the unrecovered investment of the asset and its removal cost are over or under-accrued.

Q. How does the Study determine the theoretical reserve?

A. In the Study, theoretical reserves were computed based on projected plant balances as of December 31, 2016. The theoretical reserve is calculated using a reserve model that relies on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. More specifically, the theoretical reserve of a property group is determined from the estimated remaining life of the group, the total life of the group, and estimated net salvage. This computation for the straight-line, remaining-life theoretical reserve ratio, which I describe in more detail on pages 23-25 of Exhibit DAW-1, involves multiplying the vintage balances within the property group by the theoretical reserve ratio for each vintage.

Q. Is it desirable for the depreciation reserve to conform to the theoretical reserve?

A. Yes. It is desirable for the depreciation reserve to conform as closely as possible to the theoretical reserve. When remaining life rates are used, the theoretical reserve provides the basis for any over or under-accrual in setting the depreciation rates at the appropriate level based on current parameters and expectations. Overall, the study found a deficit of $139.2 million at December 31, 2016 based on the recommended life and net salvage parameters. The depreciation rates are designed to eliminate that deficit over the remaining life of the assets.

C. NET SALVAGE AMOUNTS OR PERCENTAGES

Q. What is net salvage as determined for all the company's plant assets?

A. While discussed more fully in the Study itself, net salvage is the difference between the gross salvage (what the asset was sold for) and the cost of removal (COR) (cost to remove and dispose of the asset). If the COR exceeds gross salvage, net salvage is negative. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of any capital additions versus the retirement.

Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the assets retired.

Q. How is net salvage determined for Steam and Other Production Plant in the Study?

A. As discussed above, the Study uses the interim net salvage for each generating unit. An interim net salvage percentage is calculated and represents the estimated removal cost for interim retirements that will occur annually over the remaining life of each generating unit. The interim net salvage percentages proposed for Production plant accounts are shown in Exhibit DAW-2, Schedule 2 and in Appendix D-2 of Exhibit DAW-1. The dismantlement cost (terminal cost of removal) estimates for each generating unit are not included since those amounts are determined in a separate study. The Study separately calculates the net salvage percentages for the Transmission, Distribution, and General Plant accounts.

Q. How did you determine the net salvage percentages for each asset group in Transmission, Distribution, and General Plant?

A. To determine the appropriate net salvage percentages for each account, I start by using an industry-standard method that divides the current cost of salvage or removal by the original installed cost of the assets retired. However, judgment also is applied to select a net salvage percentage that represents the future expectations for each account. To apply this judgment, historical salvage and removal data by functional group is compiled to determine values and trends in gross salvage and removal cost. The functional data for retirements, gross salvage, and COR covered the period from 1981-2014 and is detailed in the Study. Moving averages are calculated with this data, with the intent to remove timing differences between retirement and salvage and removal cost; those moving averages are analyzed over varying periods up to 34 years. These calculations are found in Appendix E of Exhibit DAW-1.

Q. Is it not sufficient to analyze historical data to form your life and net salvage estimates?

A. No. Historic life and salvage data is one factor to consider in making life and net salvage recommendations, but it is crucial to incorporate future trends, changes in equipment and Company-specific operational information before finally making life and net salvage recommendations. Once all the calculations and data are prepared, I take into account my judgment, Company expectations and trends to determine the appropriate net salvage percentages. A comparison of the approved and proposed net salvage percentages are shown in Exhibit DAW-2, Schedule 3 and in Appendix C of Exhibit DAW-1.

Q. Please describe some of the changes in the net salvage percentages for the various accounts.

A. The detailed analysis of each account is described fully in Exhibit DAW-1, pages 55-110. Net salvage is trending toward higher negative net salvage due to the increased cost of labor, safety, and environmental compliance related to retiring utility assets and the longer lives experienced for many assets. For Gulf, net salvage for 12 accounts decreased (became more negative) while the remaining 16 accounts remained unchanged. Examples of some of the changes in net salvage are:

- The most significant decreases of 30 percent or more (more negative) in net salvage percentages were in: Transmission Account 355, Poles & Fixtures, which decreased from negative 40 percent to negative 75 percent; Distribution Account 365, Overhead Conductors & Devices, which decreased from negative 20 percent to negative 50 percent; and Distribution Account 369.1, Overhead Services, which decreased from negative 45 percent to negative 75 percent.
- Two other Distribution Accounts 369.2, Underground Services and 373, Street Lighting had a decrease from negative 10 percent to negative 20 percent net salvage. Factors impacting removal costs are discussed in the Study. See pages 53-54 of Exhibit DAW-1.

D. REMAINING LIFE ANALYSIS

Q. Does the study conduct life analysis for Production units?

A. Yes. The terminal retirement dates are inputs used in the Study to derive the average remaining life depreciation rate for generation. These terminal retirement dates were provided by the Company to me. These dates are consistent with current operating expectations, environmental legislation, and resource plans. Interim retirement ratios are also inputs used in the Study to derive the average remaining life depreciation rate for generation assets.

Q. Can you explain interim retirement ratios and what purpose they serve in the Study?

A. Yes. As detailed in the Study, interim retirement ratios were used to model the retirement of individual assets within primary plant accounts for each generating unit prior to the terminal retirement of the facility. The life span procedure assumes all assets are depreciated (straight-line) for the same number of periods and will retire at the same time (the terminal retirement date). Adding interim retirement ratios to this procedure reflects the fact that some of the assets at a power plant will not survive to the end of the life of the facility and should be depreciated (straight-line) more quickly and retired earlier than the terminal life of the overall facility. By applying interim retirements, recognition is given to the obvious fact that generating units will have retirements of depreciable property before the end of their lives. The interim retirement methodology reflected in the Study was used in the development of the depreciation rates approved in Docket No. 090319-EI and in the calculation of the Company's proposed Production depreciation rates. The interim retirement ratios proposed for Production accounts are shown in Exhibit DAW-2, Schedule 4 and Exhibit DAW-1 on Appendix D-2.

Q. What method does the study use to analyze historical data for Transmission, Distribution, and General Plant to determine life characteristics?

A. All Transmission, Distribution, and General Plant accounts were analyzed using either the actuarial analysis (retirement rate method) or the simulated plant record balances (SPR) method to estimate the life of the property in each account. In much the same manner as human mortality is analyzed by actuaries, depreciation analysts use models of property mortality characteristics that have been validated in research and empirical applications.

Q. How did you determine the average service lives for Transmission, Distribution, and General Plant?

A. As noted above, actuarial or SPR analysis was used to determine the appropriate average service lives for each account in Transmission, Distribution, and General. Graphs and tables supporting the analysis and the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the Determination of the Lives section of Exhibit DAW-1, pages 55-110. A summary comparison of the approved and proposed depreciable lives is shown in Exhibit DAW-2, Schedule 5 and in Appendix C of Exhibit DAW-1.

Q. Please describe some of the changes in the average service lives for the various Transmission, Distribution, and General accounts.

A. For Transmission, Distribution, and General Accounts, there are 20 accounts with increasing lives; four accounts with decreasing lives; and four accounts where there is no change. Examples of some of the changes in average service lives for Transmission, Distribution, and General Plant are as follows:

- The largest increases, greater than five years, in life were in:
    - Distribution Account 367 Underground Conductors & Devices, which increased by nine years;
    - Distribution Accounts 365 Overhead Conductors & Devices, 366 Underground Conduit, and 369.1 Overhead Services, all of which increased by seven years; and

  - Transmission Accounts 352 Structures & Improvements, 354 Towers & Fixtures, 358 Underground Conductors & Devices, and Distribution Account 369.2 Underground Services, all increased by five years. An explanation for the increases is detailed for each account in the Study.
- The largest decreases in life were:
  - Distribution Account 370, Meters, which decreased by 17 years due to the change from electro-mechanical to electronic meters;
  - Distribution Account 362, Station Equipment, which decreased by eight years; and
  - Transmission Account 353 Station Equipment showed a five year decrease in life.

Two other accounts showing a decrease in life had a decrease of two years or less, and there were nine accounts with no change. An explanation for the decreases is detailed for each account in the Study.

E. DEPRECIATION RATES AND DEPRECIATION ACCRUAL RATES

Q. Having determined the theoretical reserve, the book reserve, calculated net salvage and the remaining lives through the Study, please describe the final steps in calculating the depreciation rates and annual depreciation accrual expense.

A. To determine depreciation rates the following process occurred: 1) historic data through December 31, 2014 and judgment were used to estimate life and net salvage parameters; and 2) the vintage balances and reserves at

December 31, 2016 were used to compute the proposed depreciation accrual expense and rates.

In the Study, calculation of the depreciation accrual rates is computed using the same methodology as was used in developing the depreciation rates approved by the Commission in Docket No. 090319-El. The computation of accrual rates are shown in Appendix A of Exhibit DAW-1

V. CHANGE IN DEPRECIATION EXPENSE AS A RESULT OF THE PROPOSED DEPRECIATION RATES

Q. What is the purpose of this section of your direct testimony?

A. In this section of my direct testimony, I discuss the change in depreciation expense as a result of the proposed depreciation rates. Specifically, I explain why Gulf's depreciation expense is increasing, as well as detail the change in depreciation expense.

Q. Please summarize the depreciation study results with respect to depreciation changes in depreciation expense.

A. Based on the revised depreciation rates indicated in the Study, as applied to forecasted plant balances as of December 31, 2016, the overall change in annual depreciation expense is an increase of approximately $20.4 million. As shown previously in Exhibit DAW-2, Schedule 1, this increase reflects an increase of $16.2 million in Production, consisting of Steam Production of $9.5

million and Other Production of $6.8 million. The change in Steam Production is driven by the Crist Plant and the reflection of interim retirements. The change in Other Production reflects the effect of the retirement and replacement of turbines at a plant prior to the end of the life of a unit. There is an increase of $3.7 million in Transmission, a decrease of $141 thousand in Distribution, and an increase of $619 thousand in General.

There are two accounts driving the increase in the Transmission function: 353 Station Equipment and 355 Poles and Fixtures. Account 353 had a decrease in life and more negative net salvage. Account 355 had a slight increase in life but experienced significant more negative net salvage. As discussed previously, changes in parameters affect the reserve position, which is evident in these two accounts.

As shown in Exhibit DAW-1, Appendix F, the theoretical reserve is much higher than the book reserve, creating a deficit that is recovered over the remaining life of the account and increases the depreciation rate. Detailed Production rates by plant and account are shown in Exhibit DAW-1, Appendix A-1 and A-2. Rates by account for Transmission, Distribution, and General are shown in Exhibit DAW-1, Appendix A-3.

Q. Mr. Watson, do you have any concluding remarks?

A. Yes. The Study and analysis performed under my supervision fully supports setting depreciation rates at the level I have indicated in my testimony. The Company should continue to periodically review the annual depreciation rates for its property. In this way, the Company's depreciation expense will more accurately reflect its cost of operations and the rates for all customers will include an appropriate share of the capital expended for their benefit.

The Study for Gulf's electric depreciable property for actual plant assets as of December 31, 2016 describes the extensive analysis performed and the resulting rates that are now appropriate for Company property.

Q. Does this conclude your direct testimony?

A. Yes, it does.

GULF POWER COMPANY

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

Q. Please state your name and business address.

A. My name is Steve Harris. My business address is 555 12th Street Suite 1100, Oakland, California 94607.

Q. What is your position?

A. I am a Senior Manager with CoreLogic, Inc. Insurance & Spatial Services, Consulting Services Group. I was formerly with EQECAT, Inc. which was acquired by CoreLogic in December 2013.

Q. What are your responsibilities as Senior Manager with CoreLogic, Inc. Insurance & Spatial Services Consulting Services Group?

A. As a manager with CoreLogic's Consulting Services group, I provide catastrophic risk management consulting services to major insurers, re-insurers, corporations, governments and other financial institutions. These services provide catastrophic underwriting, pricing, risk management and risk transfer model analytics that are used extensively in the insurance industry. These services provide the financial, insurance and brokerage communities with a science and technology-based source of independent quantitative risk information.

Q. Please state your prior work experience and responsibilities.

A. Over the past 30 years, I have conducted and supervised independent risk and financial studies for public utilities, insurance companies and other entities both regulated and unregulated. My areas of expertise include natural hazard risk analysis, operational risk analysis, risk profiling and financial analysis, insurance loss analysis, loss prevention and control, business continuity planning and risk transfer. A significant portion of my consulting experience has involved the performance of multi-hazard risk studies, including earthquake, ice storm and windstorm perils, for electric, water and telephone utility companies, as well as insurance companies.

I have performed or supervised storm loss and reserve analyses for utilities including Gulf Power Company (Gulf or the Company), Tampa Electric Company, Florida Power & Light Company, Duke Energy, and others. Additionally, I have performed loss analyses for earthquake hazards for utilities including the Los Angeles Department of Water and Power, the Sacramento Municipal Utility District, British Columbia Hydro, and others.

For energy companies that have assets in a wide array of geographic locations, I have performed or supervised multi-peril analyses for all natural hazards, including earthquakes, windstorms and ice storms.

Q. What is your educational background?

A. I received Bachelors and Masters Degrees in engineering from the University of California at Berkeley. I am a licensed civil engineer in the State of California.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the results of CoreLogic's 2015 independent analyses of risk of uninsured hurricane loss to Gulf transmission and distribution assets. The study includes a Hurricane Loss Analysis and a Reserve Performance Analysis.

Q. Are you sponsoring any exhibits?

A. I sponsor Exhibits SPH-1 and SPH-2. The information contained in these exhibits is true and correct to the best of my knowledge.

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

A. No.

I. PURPOSE AND SUMMARY

Q. Please briefly describe the studies performed for the Company.

A. CoreLogic performed two analyses relative to Gulf's property damage reserve (reserve): the Hurricane Loss Analysis and the Reserve

Performance Analysis. The Loss Analysis is a probabilistic storm analysis that uses proprietary software to develop an estimate of the expected annual amount of uninsured hurricane damage to which Gulf is exposed. The Performance Analysis is a dynamic financial simulation analysis that evaluates the performance of the reserve in terms of the expected balance of the reserve and the likelihood of inadequate funds over a five-year period. The Performance Analysis is based on the potential uninsured damage determined from the Loss Analysis, at a given initial reserve balance and annual accrual level.

Q. Please summarize the results of your analyses.

A. The Loss Analysis concluded that the total expected annual, uninsured damage to Gulf's system from all hurricanes is estimated to be $9,600,000. The annual reserve obligation (the portion of the expected annual damage that would be charged against the reserve) is estimated to be $7,900,000 based on Gulf's historical experience.

The Reserve Performance Analysis demonstrated that, assuming a $35,700,000 initial reserve balance and the currently approved accrual level of $3,500,000, an expected reserve balance at the end of five years is only $13,100,000, and there is a 23 percent probability that the reserve would be at zero or negative, at the end of the five year simulation time horizon.

II. LOSS ANALYSIS

Q. Please summarize the Loss Analysis.

A. The Loss Analysis determined the expected magnitude of hurricane damage to Gulf's transmission and distribution (T&D) system. These costs are associated with repair and/or replacement of Gulf's T&D assets necessary to promptly restore service in a post storm environment.

Q. Please describe the computer software used to perform the Loss Analysis.

A. Risk Quantification and Engineering (RQE®) is a probabilistic catastrophe simulation model designed to estimate damage due to the occurrence of hurricanes. Probabilistic annual damage is computed using the results of thousands of random variable storms. Annual damage estimates are developed for assets and aggregated to produce the overall portfolio damage amounts. RQE's climatological models are based on the National Oceanic and Atmospheric Administration's (NOAA) National Weather Service (NWS) Technical Reports. CoreLogic's proprietary computer software model has been evaluated and determined acceptable by the Florida Commission on Hurricane Loss Projection Methodology (FCHLPM) for projecting hurricane loss costs.

Q. Why are catastrophe simulation models used for hurricane loss projection?

A. Catastrophe simulation modeling is the process of using computer-assisted calculations to estimate the damage that could be sustained due to natural disasters such as hurricane events. Catastrophe simulation modeling combines actuarial science, engineering, meteorology, and computer science to allow loss estimation of infrequent events. The insurance industry and risk managers use catastrophe simulation modeling to assess and manage risks. Catastrophe simulation modeling is the current standard of risk assessment in the insurance industry.

Q. Does RQE take into account storm frequency and severity?

A. Yes. The analysis is based on storm frequency and severity distributions developed from the entire 112 year historical record.

Q. Do the storm frequency assumptions include the possibility of having multiple hurricane landfalls within Florida in any given year?

A. Yes. RQE includes the possibility of having multiple hurricane landfalls within Florida in any given year, including the impact of such landfalls on aggregate losses. So the possibility of having loss experiences like the 2004-2005 hurricane seasons when multiple hurricanes hit Florida is captured in the model. Similarly, the storm frequency assumptions also capture the possibility of having no hurricane landfall in Florida. The use of the full 112 years of historic storm data to develop storm frequencies assures that the model simulates years without storm landfalls as well as years with single and multiple landfalls.

Q. What were the results of the Loss Analysis?

A. I concluded that the total expected annual damage to Gulf's T&D system from all hurricanes is estimated to be $9,600,000. The annual reserve obligation associated with this total expected annual damage is estimated to be $7,900,000. The $1,700,000 difference reflects that some storm restoration expenditures are either capital costs or other O&M costs that are not allowed to be charged against the reserve based on Gulf's past storm experience.

Q. What does this expected annual damage estimate represent?

A. The expected annual damage estimate represents the average annual cost associated with damage to T&D assets, resulting from hurricanes over a long period of time.

Q. Did the Loss Analysis include consideration of the effects of Gulf's Storm Hardening Program?

A. Yes. Gulf's Witness Smith provided an opinion of the expected impact of the Program through 2015 on T&D system loss for our analysis.

Q. Is the Loss Analysis performed for Gulf the same analysis performed for insurance companies to price an insurance premium?

A. Yes. Hurricane catastrophe-simulation modeling and analysis would be similar for an insurance company, electric utility or other entity. The expected annual damage is also known as the "Pure Premium," which, when insurance is available, is the insurance premium level needed to pay just the expected losses. Insurance companies add their expenses and profit margin to the Pure Premium to develop the total premium charged. If adequate insurance coverage was available, affordable, and Gulf obtained such insurance, the premiums charged to customers as an expense would include the pure premium cost plus added expenses and profit.

III. PERFORMANCE ANALYSIS

Q. Please summarize the Performance Analysis.

A. CoreLogic performed a dynamic financial simulation analysis of the impact of the estimated windstorm damage on the Gulf reserve for the specified initial reserve balance and level of annual funding. The starting assumption for the Reserve Performance Analysis was an actual balance in the property damage reserve of $35,700,000 as of year-end, 2014. This analysis performed 10,000 simulations of windstorm damage within the Gulf service area, each covering a five year period, to determine the effect of the charges for damage on the reserve. Monte Carlo simulations were used to generate damage samples consistent with the expected $7,900,000 annual Loss Analysis results chargeable to the reserve. The analysis provides the expected balance of the reserve in each year of the simulation accounting for the annual accrual, investment income, expenses, and damage using a financial model.

Q. What is a Monte Carlo analysis?

A. Monte Carlo simulation is a widely used computational technique employed to understand the impact of uncertainties in financial, cost, and forecasting models. The Monte Carlo simulation technique is used to model the reserve performance from multiple storm seasons and simulate the variable nature of storm damage. The storm damage for each of five consecutive years is stochastically (randomly) sampled consistent with the results of the Loss Analysis probabilities for single year losses. Many years have no damage, and some years have damage of varying amounts. A few years have catastrophic damage. Each five years of storm losses, along with the initial reserve balance, and the accruals are used to calculate the balance of the reserve in each year of a five-year simulation. Because storm seasons and damage are highly variable, 10,000 five year sample simulations are performed. The large number of simulations allows the determination of the average (expected or most probable) reserve balance, and it shows what range of reserve balances could occur.

Q. Are the results of the Loss Analysis incorporated in the Performance Analysis?

A. Yes. Both the likelihoods and amounts of uninsured annual damage determined in the Loss Analysis are used to simulate damage in each of the five years in the Reserve Performance Analysis in order to determine the likelihood of the reserve having adequate funds.

Q. Please summarize the results of the Performance Analysis.

A. The reserve performance can be viewed in terms of the expected balance of the reserve and the likelihood of inadequate funds occurring in any year of the five-year period. Based on an initial reserve balance of $35,700,000 and an annual accrual of $3,500,000, the expected balance of the reserve at the end of five years is only $13,100,000, and there is a 23.1 percent chance of the fund reaching zero or becoming negative.

Q. What did your evaluation show with respect to a $35,700,000 initial reserve balance and a $3,500,000 annual accrual?

A. It showed that the reserve value of $35,700,000 combined with annual accruals of $3,500,000 is too small to pay for most storm damage. In fact, it is too little to pay for all Category 1, also referred to as Saffir-Simpson Scale (SSI) Category, or Category 2 single storm events.

For example, Schedules 1 and 2 of Exhibit SPH-1 show the frequency weighted average ("mean") damage from single hurricane events of Category 1 and Category 2, respectively, that make landfall within 10 mile intervals along the Gulf Coast in and around Gulf's service area. Also shown are the initial (Year 0) and final (Year 5) balance values of the reserve from the CoreLogic Reserve Performance Analysis for comparison with the potential hurricane damage. The reserve analysis shows the reserve balance to decline in each year from its initial value of $35,700,000 until it reaches $13,100,000 at Year 5.

With a reserve balance of $35,700,000, the reserve would be inadequate to cover all mean Category 2 hurricane landfall damage. The largest single Category 2 hurricane damage occurs at milepost 840 (near Pensacola) and is approximately $110,000,000. A reserve balance of $35,700,000 at Year

0, or $13,100,000 at Year 5, is inadequate to cover the largest, as well as the mean damage, at milepost 840 from Category 2 events.

Q. Did you evaluate the sufficiency of the reserve to cover damage from hurricanes that make landfall at various locations along the coast?

A. Yes. The potential damage from Category 1 through Category 4 storms in the Storm Study at the various landfall mile posts show that the projected reserve would not be adequate to cover the mean estimated damage associated with the majority of Category 1 through Category 4 storms.

For example, in Category 1 storms a reserve of $13,100,000 would cover mean Category 1 hurricane projected damage at only 10 of the 24 landfall mile posts. A reserve of $35,700,000 would cover mean Category 1 hurricane projected damage at 24 of the 24 landfall mile posts.

Similarly, for Category 2 storms a reserve of $13,100 000 would cover mean Category 2 hurricane projected damage at only five of 24 landfall mile posts. A reserve of $35,700,000 would cover mean Category 2 hurricane projected damage at only 17 of 24 landfall mile posts.

Similar figures for Category 3 and 4 storms are shown on pages 4-4 and 4-5 of Exhibit SPH-2, “Gulf Power Company Hurricane Loss and Reserve Performance Analysis”.

Category 3 storms. A reserve of $13,100,000 would cover mean Category 3 hurricane projected damage at only two of 24 landfall mile posts. A reserve of $35,700,000 would cover mean Category 3 hurricane projected damage at only nine of 24 landfall mile posts.

Category 4 storms. A reserve of $13,100,000 would cover mean Category 4 hurricane projected damage at only one of 24 landfall mile posts. A reserve of $35,700,000 would cover mean Category 4 hurricane projected damage at only three of 24 landfall mile posts.

Q. What would the expected reserve balance be if Gulf experienced little or no hurricane storm damage over the following five years?

A. Even if Gulf experienced little or no hurricane storm damage over the following five years (a less than 5 percent probability) and incurred no other property damage expenses, the reserve balance would grow only to $58,821,395 at the existing $3.5 million accrual. This reserve value is only about 7 percent greater than the maximum of the Target Range of $48,000,000 to $55,000,000 authorized by the FPSC in the 2012 test year rate case. More significantly, a $58,821,395 reserve balance is only about half of the expected damage from the worst Category 2 storm. The effect of the Commission’s 2012 order to increase the property damage reserve target was helpful, and if Gulf continues to have favorable storm experience, it will allow continued accumulations to the reserve, therefore increasing the amounts and numbers of possible storms that the reserve can fund. The reserve will not, however, be able to fund all Category 1 or Category 2 storms without higher accruals and a higher Target Range for the reserve than currently authorized.

Were the reserve to be adequately funded for Category 1 and Category 2 storms, it would still be far below the levels of damage that might be expected from Category 3 and Category 4 storms. The mean damage from these events as shown on pages 4-4 and 4-5 of Exhibit SPH-2 can be in excess of $100,000,000 to $250,000,000, with the largest damage being much greater than these mean values.

Q. Is your analysis of the performance of the reserve conservative?
A. Yes, I believe my analysis of the reserve performance is conservative for several reasons.

First, the analysis estimates only hurricane losses and their effect on the reserve. While hurricane losses are believed to have the largest loss potential, there are several ways unrecovered losses to the reserve have occurred in the past and could again in the future. These include tropical storm losses (which are more frequent than hurricanes), winter storms, fires, floods, and other perils. Losses due to other perils, in addition to the hurricanes losses which I modeled, could result in an average annual loss that is significantly greater than the $9.6 million estimated for hurricanes alone.

Other liabilities to the reserve that were not modeled include deductible costs associated with all-risk insurance policies covering general property, and power plants. Hurricanes, storms, floods, fires and other loss events could result in significant insurance policy deductibles. In addition, there is a small but real possibility that in extreme events, losses could exceed insurance policy coverage limits. Losses in excess of policy limits could be liabilities of the reserve.

Lastly, the values of the T&D assets at risk that were used in the hurricane loss analyses are based on the available year end 2014 Gulf Power accounting records when our analyses were initiated. These values do not include any T&D assets placed into service after 2014. Also, for an assumed cost escalation for the T&D assets of 3.68 percent per year over two years (2014 to 2016), this represents about a 7.5 percent underestimate of the values at risk. Both the single year loss estimate and the five-year prospective analyses for the reserve performance from 2016 through 2021 are therefore based on a low biased value of the assets at risk and contribute to a conservative estimate of the reserve performance.

Q. Please summarize the results of your analyses.

A. The Loss Analysis concluded that the total expected annual damage to Gulf's system from all hurricanes is estimated to be $9,600,000 in 2014 dollars. The corresponding annual reserve obligation is estimated to be $7,900,000.

The Reserve Performance Analysis demonstrated that assuming a $35,700,000 initial reserve balance and an accrual level of $3,500,000 would result in an expected reserve balance of only $13,100,000 and a 23.1 percent probability of the reserve reaching zero or becoming negative at the end of the five year simulation time horizon.

The $35,700,000 reserve and combined annual accruals of $3,500,000 are too small to pay for most storm damage. It would not even cover all the mean Category 1 and Category 2 single storm event damage, and it would only cover a small number of the mean Category 3 and Category 4 event damage.

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

GULF POWER COMPANY

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

Q. Please state your name and business address.

A. My name is James Garvie. My business address is 30 Ivan Allen Jr. Boulevard, Atlanta, GA 30308.

Q. By whom are you employed?

A. I am employed by Southern Company Services (SCS) as Compensation, Benefits & Human Resources Operations Vice President.

Q. What are your responsibilities as Compensation, Benefits & Human Resources Operations Vice President for SCS?

A. I am responsible for leading the compensation, benefits, retirement and human resources operations functions for Southern Company and its affiliates, including Gulf Power Company (Gulf or the Company). I have held these responsibilities since I joined SCS in 2011 as Compensation and Benefits Director. My job title changed in December 2015.

Q. Please describe your prior work experience and responsibilities.

A. Prior to joining SCS, I was a Director with The Alexander Group, a management consulting firm, where I advised management of Fortune 500 companies on a wide range of human resource issues.

Before my position with The Alexander Group, I worked at Blue Linx, a large building products distribution company, in a leadership position managing all aspects of sales, human resources, payroll and human resources information systems. Previous to that employment, I worked at Georgia-Pacific in increasing roles of responsibility in employee compensation and the accounting/finance area.

Q. What is your educational background?

A. I have a Masters of Business Administration degree from Kellogg School of Management at Northwestern University in Evanston, Illinois, and a Bachelor of Finance degree from the University of Incarnate Word in San Antonio, Texas. I am also a Certified Compensation Professional (CCP).

Q. Please describe your credentials as a compensation professional.

A. I have deep expertise and knowledge of compensation strategy, design and competitiveness gained through:

- Approximately eighteen years of direct and related compensation experience,
- Seven years in consulting across many industries, and
- Completion of a series of nine examinations to earn designation as a Certified Compensation Professional (CCP).

Q. In your experience as the SCS Compensation, Benefits and Human Resources Operations Vice President and a CCP, is it customary to rely upon reports and studies prepared by compensation and benefit consulting firms?

A. Yes. Reports and studies prepared by recognized third-party experts are commonly used and relied upon by corporate compensation and benefit experts to make decisions. Such studies are regularly used as a primary basis to determine the market level of compensation and benefits.

Q. What is the purpose of your testimony?

A. Gulf's compensation and benefits programs for employees are at the median of the market and designed as a "total package" to support our customers' need for safe and reliable electric service. The purpose of my testimony is to outline Gulf's customer-based fundamental beliefs on compensation and benefits, describe the design and competitiveness of Gulf's total compensation and benefits programs, justify Gulf's expense budget for employee compensation and benefits, and demonstrate that the level of compensation and benefit costs requested in this case is reasonable, prudent, and necessary to enable Gulf to continue to provide safe and reliable electric service to our customers.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit JMG-1, Schedules 1 through 5. The information contained in Schedules 1 through 5 is true and correct to the best of my knowledge and belief, and except for Schedules 3 through 5 the Exhibit was prepared under my direction and control.

- Schedule 1, Gulf Power Company Total Compensation Mix between Base and At-Risk Pay

- Schedule 2, Gulf Power Company Base Salary and Total Compensation to Market Median
- Schedule 3, Willis Towers Watson Memorandum on Audit of Gulf Power Company's Pay Programs
- Schedule 4, Willis Towers Watson Comparison of Employer-Paid Benefit Value
- Schedule 5, Aon Hewitt Comparison of Employer-Paid Benefit Value

I. GULF'S APPROACH TO COMPENSATION AND BENEFITS

Q. What are Gulf's fundamental beliefs regarding compensation and benefits?

A. Gulf fundamentally believes that the design of compensation and benefit programs should support our customers' need for safe and reliable electric service. Gulf takes a holistic approach to designing and valuing its compensation and benefit programs as a total package.

Gulf has developed four fundamental beliefs which serve as the foundation for the design and evaluation of our total package of compensation and benefits.

1. Long-term customer value is created through retaining employees.
    - Superior organizational performance is gained through attracting talent for the long term and placing value on the knowledge, skills, and experience gained through longevity.

2. The health and well-being of the workforce improves productivity.
   - A healthy workforce sustains employee commitment and top performance, which positively affects productivity and customer satisfaction.
3. Linking pay to performance efficiently and economically aligns employee and customer interests.
   - Placing a portion of employee compensation at-risk drives our employees to achieve higher levels of performance, customer satisfaction, and productivity.
4. Compensation and benefits program competitiveness is critical.
   - We must continuously evaluate our programs to ensure they are competitive to attract, engage, retain, and motivate employees, and that the programs are effective and financially sustainable.

Q. Please describe the benefits of evaluating Gulf's compensation and benefits as a total package.

A. Evaluating compensation and benefits as a total package has two primary benefits:

1. Cost efficiency. Evaluating compensation and benefits as a whole allows Gulf to maximize the efficient use of resources essential to serving the customer and align resources with the most important elements of employee attraction and retention.
2. Retention and attraction of employees. Evaluating compensation and benefits holistically allows for the alignment of programs with Gulf's need to attract, engage, retain, and motivate its highly skilled workforce.

Q. What are the components of Gulf's total package of compensation and benefits?

A. The compensation portion of Gulf's total package consists of base pay and at-risk pay. The benefits portion consists of health benefits, retirement benefits, and other benefits such as life and disability insurance. Gulf's total package of compensation and benefits is aligned with its fundamental beliefs.

Q. How does Gulf measure the competitiveness of its compensation and benefits programs against the external market?

A. Gulf's total compensation and benefits program is managed to the median of the external market. Median of the market represents the middle of the market where half of the market is higher and half is lower. By managing to the median, we want to provide competitive compensation and benefits that will allow us to attract, engage, retain, and motivate qualified employees while also managing costs. Gulf utilizes recognized compensation and benefit consultants, such as Willis Towers Watson and Aon Hewitt, to benchmark our compensation and benefit programs against the external market.

II. TOTAL COMPENSATION

Q. What is Gulf's approach for designing employee compensation?

A. Our employee compensation is designed to provide total compensation that will allow us to attract, engage, retain, motivate, and competitively compensate employees based on individual and Company performance. The total compensation an employee receives is provided in the form of base pay and at-risk pay. The at-risk pay portion may be paid based on the achievement of goals that benefit our customers. Providing total compensation in this form, with a portion tied to performance, has allowed Gulf to develop a culture of individual, team and customer accountability.

Q. Please describe how Gulf's total compensation of base pay and at-risk pay is determined.

A. Annually, we go through a thorough and rigorous review to ensure that the design and competitiveness of our total compensation is at the median of the market and is aligned with our fundamental beliefs. The review has the following steps:

1. Determine the market median total target compensation for each position through the use of multiple compensation surveys published by recognized third-party sources. Total target compensation is comparable to what companies with whom we compete for talent offer their employees performing similar jobs with similar responsibilities and skill sets.

2. Based on the market, a portion of each individual's total target compensation is subtracted and allocated to at-risk pay based on goals that benefit our customers, directly aligning individual compensation with customers' interests. Positions with a greater influence over Company performance have a greater portion of total compensation that is allocated to at-risk pay.
3. Review the allocation of total compensation between base pay and at-risk pay to ensure it aligns with our fundamental beliefs.

Q. Why has Gulf chosen to provide total compensation in the form of base pay and at-risk pay?

A. Gulf has chosen to provide total compensation in the form of base pay and at-risk pay to emphasize performance and to align the interests of our employees with our customers. Exhibit JMG-1, Schedule 1 illustrates how a philosophy of providing total compensation in the form of base pay only with no at-risk pay compares to Gulf's philosophy of providing total compensation in the form of base pay and at-risk pay. Providing total compensation in the form of base pay only with no at-risk pay would not be in the best interest of our customers. It would result in higher fixed costs for our customers and would eliminate a powerful tool that drives employees to put the customer at the center of all we do while sustaining the financial integrity of the Company.

Q. Is the use of base pay and at-risk pay to form an employee's total compensation unique to Gulf?

A. Not at all. Providing total compensation in this manner is consistent with how utilities and general industry compensate their employees. We have found that having total compensation provided in this manner has allowed Gulf to develop a culture where our employees are consistently engaged with their work, focused on the customer, focused on the success of the company, and driven to deliver the highest levels of customer service.

Q. Do all employees have compensation that is provided in the form of at-risk pay?

A. Yes. All employees have some portion of their total compensation that is at risk and tied to the achievement of annual goals. Depending on the achievement level of the annual goals, the at-risk portion of their pay may be paid after the end of the year. It is not guaranteed to be paid each year. Employees with a greater influence over the long-term success of the Company have a larger portion of their total compensation at risk, some of which is tied to the achievement of long-term goals. Depending on the achievement level of the long-term goals, the at-risk portion of their pay may be paid after the end of three years. It also is not guaranteed to be paid each year. Lower goal achievement results in lower at-risk pay, and higher goal achievement results in higher at-risk pay. An employee's total compensation, which includes base pay and at-risk pay, will vary from year to year based on employee and Company performance.

Q. What are the annual goals for the at-risk portion of total compensation?

A. Gulf's at-risk pay goals are all performance-based and designed to align the employees' interest with the customers' interest. The annual goals include three categories that all serve to enhance Gulf's service to customers—Gulf operational performance, Gulf net income performance and Southern Company earnings per share performance. Each of the at-risk pay goals is designed to focus employees on providing safe and reliable electric service to our customers.

Gulf's operational goals focus employees on continually improving the Company's operational performance for our customers. The goals focus employees' attention on safety, customer satisfaction, generation availability, transmission and distribution reliability, and company culture. Safety is measured to ensure the protection of employees, customers and communities. Customer satisfaction is important to ensure that our customers are satisfied with the level of service we provide and that our employees are continually striving to improve the customer experience. Generation availability and transmission and distribution reliability are important to ensure the availability of power from our generation fleet and the reliable delivery of that power to our customers. Culture is measured to ensure that we are diversifying our workforce to reflect our customer base and developing our employees so that they may reach their full potential in an atmosphere of customer service and safety.

Gulf's net income goal focuses employees on being efficient with Company resources and continually looking for ways to improve Gulf's overall business. Employees working to keep expenses down, whether through efficient purchasing practices, budget management, or effective use of personnel resources, reduces costs that are recovered through rates to Gulf's customers. Employees working on economic development efforts in the community benefit customers through economic growth, community stability, and improving Gulf's financial performance.

Gulf's earnings per share goal focuses employees on running the Company efficiently, not only as a stand-alone utility, but also as part of the Southern Company. This goal is a testament to the advantage of Gulf being a part of Southern Company. In their normal course of business, Gulf employees have access to specialized expertise and bulk purchasing leverages due to Gulf's relationship with Southern Company. If Gulf had to purchase or hire this expertise as a stand-alone utility, these costs would likely be greater. Gulf employees' ready access to this expertise and purchasing leverage helps better provide safe and reliable electric service to our customers.

Q. Have there been any changes to the annual goals in Gulf's at-risk pay program since the rate case filed by Gulf in 2013?

A. Yes. The goal based on Gulf's net income performance replaced a previous goal based on return on equity performance. This change was made to provide a goal that all employees connect with and better understand.

Q. Please describe the long-term goals for Gulf's at-risk compensation program.

A. The long-term goals also include three categories—Southern Company total shareholder return, Southern Company earnings per share, and Southern Company equity weighted return on equity. These goals focus employees on planning and managing Gulf's resources efficiently in the short and long term. Managers with greater influence over the long-term success of the Company are encouraged through these long-term goals to take a whole-company approach to their area of responsibility. It is in our customers' best interest to drive our employees to achieve long-term goals. Well executed long-term planning, budgeting, and implementation benefit our customers through better reliability, efficiency and value now and in the future.

Q. Have there been any changes to the long-term portion of Gulf's at-risk pay program since the rate cases filed by Gulf in 2011 and 2013?

A. Yes. Two new goal categories were added: Southern Company earnings per share performance and Southern Company equity weighted return on equity performance. In addition to adding the new goal categories, the Stock Option Program and the Performance Dividend Program are no longer a part of Gulf's total compensation program, although there is some small remaining cost associated with the Stock Option program in the projected total compensation cost for 2017.

Under the current long-term at-risk program, employees receive a grant of performance units at the beginning of a three-year performance period. Performance shares are denominated in units meaning no actual shares are issued on the date of grant. Each performance share unit represents one share of Southern Company common stock. Depending on the achievement level of each goal, employees may receive actual shares of Southern Company common stock at the end of each three year period.

In addition, beginning in 2017 we are reducing the number of participants in the long-term at-risk program from over one hundred to 30 participants. Consistent with our total compensation approach, we must increase the base pay for those employees who will no longer be participating in the at-risk, long-term compensation program so that their total compensation remains aligned with the median of the market. Our move to reduce the number of participants is consistent with the audit of our compensation program by Willis Tower Watson, which noted that Gulf's participants in the long-term at-risk program extended deeper in the organization than most utility peers.

Q. How do at-risk pay goals that include both operational and financial goals benefit customers?

A. A well designed total compensation program using sound compensation practice and principles provides a balance between operational focus and financial focus for both the short term and longer term to drive employee behavior in ways that balance the interests of customers and shareholders alike. A compensation plan that contained only operational goals might inappropriately drive employees to use more financial resources than necessary to achieve operational success, while a plan that contained only financial goals might inappropriately drive employees to make decisions that adversely impact operational success. As noted earlier in my testimony, operational goals focus employees on continually improving the Company's operational performance for our customers. Financial goals similarly benefit customers by focusing employees on improving the Company's financial health. Goals based on financial performance are essential to ensure cost effective operational performance and are appropriate to recognize the importance of meeting our investors' expectations in order to sustain high quality service for our customers into the future. Financial goals help ensure that decisions made by employees are optimized not just for short-term benefits, but to sustain the Company in the long run. This is particularly true in the utility industry, where decisions related to infrastructure and major projects have long-lasting financial consequences to all stakeholders, especially customers. The design of the Company's at-risk portion of total compensation to include both operational and financial goals that are measured annually and in the longer term, provides an appropriate balance where employees are driven to deliver safe and reliable electric service to our customers in a manner that is economically efficient both now and in the years to follow.

Q. Has Gulf's total compensation program been effective in attracting, engaging, retaining, and motivating the workforce?

A. Yes. The design of our total compensation program provided in the form of base pay and at-risk pay has been effective in allowing us to attract, engage, retain, and motivate our highly qualified workforce. It has enabled us to develop a culture where the customer is at the center of everything our employees do. Our employees are held accountable and know that the total compensation they receive depends on their performance in achieving goals that are focused on our customers. If the goals are achieved, then they will be compensated appropriately. If the goals are not met, their total compensation will be less, which is also appropriate.

Q. What are some of the workforce challenges that Gulf faces?

A. An ongoing challenge for Gulf and the utility industry overall is an aging workforce. The average age of our employee is 46 years old, with 17 years of service within the Southern electric system. Forty percent of our employees are eligible to retire today. Our workforce has maintained and operated our generation and distribution business at high levels and has continually and actively worked to maintain a high level of customer satisfaction. Their hard work and customer focus have helped keep Gulf's overall customer satisfaction level in the top quartile of the Customer Value Benchmark Survey for over 15 years, as described by Gulf Witness Terry. These are also the highly skilled and trained employees who help train and transfer their knowledge to our less experienced employees to ensure continued reliable electric service to our customers into the future. With such a large portion of our workforce eligible to retire now, it is crucial for Gulf to both retain its current qualified employees and to be in position to compete in the job market for hiring new employees.

A shortage of available workers in the external market with the requisite qualifications and skills is another challenge. It takes 5 to 7 years of in-house training and apprenticeship programs to reach the journeyman level of expertise required for our highly technical positions such as Line Technician, Substation Technician, or Plant Equipment Operator. Each year Gulf invests over 53,000 hours to grow and maintain the skills of our employees. This reflects an investment of approximately $3.9 million to ensure our employees have the skills required to safely perform the complex and hazardous work it takes to ensure that our customers receive safe and reliable electric service. With the shortage of qualified workers in the external market and the technical training required, it is essential that Gulf retain its current highly trained employees and be able to attract new employees in the job market.

Loss of employees to competitors is another challenge. With a shortage of qualified workers in the external market and the time and expense it takes to train employees, our experienced, well-trained and customer-oriented employees are targets of opportunity for other employers. The level of training, experience, and customer service focus of our employees is recognized in the industry and makes them highly marketable to other utilities. It is critical that Gulf is able to retain its current highly skilled workforce.

To meet these challenges, it is essential that adequate funds be available to support our total compensation and benefits package so that we can continue to attract, engage, retain, and motivate employees who continue to provide high levels of customer service and satisfaction today and into the future.

Q. What is Gulf's total projected compensation expense for 2016 and 2017?

A. As shown on MFR C-35, Gulf's 2016 projected total compensation expense is $139,667,525, and Gulf's projected total compensation expense for 2017 is $143,011,260. It should be noted that these are Total Company projections, so they include compensation recovered through adjustment clauses and other compensation removed by Gulf Witness Ritenour's net operating income (NOI) adjustments. The compensation reflected in Gulf's operations and maintenance (O&M) request for the 2017 test year is $96,101,424.

Q. How does Gulf's total compensation of base pay and at-risk pay compare to the external market?

A. Gulf annually reviews its total compensation of base pay and at-risk pay to ensure that it is appropriately aligned with the external market. We use compensation data from multiple external survey sources to benchmark our total compensation to the external market. These surveys are conducted by recognized third-party consulting firms, such as Willis Towers Watson and Mercer, who collect compensation data from survey participants, aggregate the data and provide participants with summary comparative data. As illustrated in Exhibit JMG-1, Schedule 2, when assessing both our base pay and total compensation of base pay and at-risk, Gulf is at the median or middle of the market. By maintaining total compensation relative to the median of the external market, Gulf helps ensure that it remains competitive while keeping compensation expense at reasonable levels.

Q. Has Gulf had the design and competitiveness of its compensation program reviewed by a third party?

A. Yes. Gulf had Willis Towers Watson, a nationally recognized compensation and benefits firm, recently conduct a competitive assessment of its total compensation design (base pay and at-risk pay) relative to external market practice. Willis Towers Watson's conclusion is that Gulf's compensation plans, programs, and processes are comparable to and competitive with the utility industry. Exhibit JMG-1, Schedule 3 summarizes Willis Towers Watson's analysis. As noted earlier in my testimony, Gulf is reducing the number of participants in its long-term at-risk program consistent with the results from the Willis Towers' assessment.

Q. Are Gulf's projected compensation of $143,011,260 for 2017 and projected compensation charge to O&M in the rate case of $96,101,424 reasonable and prudent?

A. Yes. The compensation portion of Gulf's total compensation and benefits package is reasonable and prudent. These expenses and expenditures are necessary to continue our efforts to attract, engage, retain and motivate a highly trained and skilled workforce with a focus on our customers.

III. LONG-TERM AT-RISK COMPENSATION

Q. Why does the design of Gulf's total compensation package include at-risk compensation based on long-term goals in addition to at-risk compensation based on annual goals?

A. Long-term goals are needed so that employee efforts to achieve short-term goals are appropriately balanced by consideration of the long-term performance of the Company. Gulf employees who have the most responsibility for decisions that impact the long-term success of the Company have a portion of their at-risk compensation tied to long-term performance, so that short-term decisions will not out-weigh longer term considerations. Thirty Gulf employees have an element of long-term at-risk compensation. Through the decisions they make in their jobs, they impact the long-term success of the Company and are responsible for how employees serve our customers and deliver safe and reliable electric service. Another important reason to allocate a portion of their total compensation to long-term at-risk pay is that for these employees, providing compensation in this form is common in the industry. Having a portion of their total compensation allocated to long-term at-risk pay is critical to ensure that Gulf remains market competitive to attract and retain these employees.

Q. Why does Gulf consider it critical to retain these employees and provide competitive compensation?

A. Gulf works hard to attract, train, and retain all of its employees. There is a considerable investment in training employees, and there is tremendous value to the customer to retain employees who have the knowledge and experience to run the Company efficiently and effectively. The employees who receive long-term at-risk compensation provide Gulf, and its customers, a wealth of experience, knowledge and skill. They make the tough decisions that result in quality of service, organize and optimize resources, understand the importance of keeping the customers as our top priority, and know how to motivate others to perform for the customer.

No well-managed company that has developed a culture of customer service and orientation can maintain such a culture if it takes advantage of those who have the greatest responsibility for leading the organization. For employees who receive long-term at-risk compensation, there are a number of attractive alternatives. The companies with whom we compete for these employees offer competitive compensation packages, and these employees are attracted by a compensation structure that rewards superior long-term performance. Unless Gulf has a competitive compensation structure, Gulf runs the risk of losing the employees who have the most responsibility for assuring Gulf's long-term performance to its customers.

Q. Mr. Garvie, please summarize your understanding of how the Commission treated Gulf's at-risk pay in Gulf's 2012 test year rate case.

A. In the 2012 test year rate case, Gulf requested Total Company compensation that included base pay and short and long-term at-risk pay. The Office of Public Counsel (OPC) argued that all at-risk, or what they called "incentive," compensation should be disallowed. The Commission rejected OPC's recommended adjustment to exclude all at-risk compensation, allowing short-term (annual) at-risk compensation but disallowing all long-term O&M compensation expenses.

Q. Why did the Commission disallow all long-term O&M compensation expense?

A. The Commission expressly recognized in its order that financial goals may benefit customers by resulting in Gulf having a healthy financial position which allows Gulf to raise funds at a lower cost than Gulf otherwise could. Additionally, the Commission stated that there was "validity" in having at-risk pay goals more closely aligned with Gulf's operations rather than Southern Company's financial position. From the Commission's order, the seemingly deciding factor that led to the disallowance of the long-term compensation was that even with the removal of long-term compensation from eligible employees, this group of Gulf employees were below but closer to the median market salary than Gulf's Covered (union) employees.

Q. Mr. Garvie, as an expert on compensation matters, what, if any, concern do you have regarding the Commission's discussion of long-term at-risk compensation in Gulf's 2012 test year rate case?

A. I do have a concern. The purpose of the comparison in this or any other compensation market assessment is between the group in question and the market median. What we are attempting to discern is how Gulf's compensation for a particular group of Gulf employees compares to other similar positions in the market where we would potentially source for talent. We are not measuring how the compensation of various groups of Gulf employees compares to each other due to the fact that the skills to perform the jobs in each group may not be comparable. The goal is to appropriately compare the responsibilities of each position to similar positions in the market in order to appropriately compensate employees compared to our competitors for talent in the market.

Q. Have you performed any analysis to determine how the total compensation of the 30 employees participating in the long-term at-risk compensation program compares to the market?

A. Yes. The total compensation of the 30 employees is at the median of the market when including long-term at-risk pay. If long-term at-risk compensation were to be excluded, their total compensation would be 22 percent below the median of the market, which would move total compensation to well out of market. This is because we determine the median of the market and then subtract a portion of the pay to allocate to the at-risk pay program for the benefit of our customers. When we reduced the number of participants in the long-term at-risk program, we had to increase the base pay of the former participants to maintain the target for the median of the market.

Q. I understand from your earlier response that you advocate comparing job groups to the market and not to one another, but if one were to perform an analysis similar to that performed by the Commission in Order No. PSC-12-0179-FOF-EI, Docket No. 110138-EI, is the compensation for any other job group within Gulf equal to or greater than 22 percent below the market?

A. No. There is no other job group within Gulf that would be 22 percent or more below the market.

Q. But, Mr. Garvie, the Commission did not say Gulf could not pay this type of compensation; it only said that this type of compensation would not be included in rates. Couldn't Gulf continue to pay this type of compensation if it is so important?

A. Long-term at-risk compensation is a legitimate and necessary cost of providing service to customers. It is intentionally designed into the compensation program for a group of employees who are critical to the long-term success of the Company and through their judgment and decisions could have a major impact on the customer. It is very important for Gulf to be able to attract and retain this group of employees. My limited understanding of ratemaking is that it is intended to cover the reasonable costs of delivering service. These costs are reasonable; indeed, they are necessary and desirable, and I see no value in suggesting they no longer be paid by disallowing them for ratemaking purposes.

Q. Why is it appropriate for the long-term, at-risk compensation program to focus on Southern Company financial performance rather than Gulf financial and operational performance?

A. Southern Company is Gulf's parent company and sole common equity investor. Gulf is dependent on Southern Company's ability to access the capital markets for equity capital. That access is extremely important to our customers who depend on Gulf to make the investments required to serve them safely and reliably. The goals of the long-term, at-risk compensation program provide a focus on goals that are a measure of Southern Company's financial integrity, which attracts investors and allows Southern to maintain access to the capital markets. The Commission recognized the value of a goal based on Southern Company financials when the Commission approved the Southern Company financial goal in allowing short-term at-risk compensation costs in Gulf's 2012 test year rate case: "We recognize that the financial incentives that Gulf employs as part of its incentive compensation plans may benefit ratepayers if they result in Gulf having a healthy financial position that allows the Company to raise funds at a lower cost than it otherwise could." (Order No. PSC-12-0179- FOF-EI at page 94)

Q. Mr. Garvie, why is Gulf seeking recovery for its long-term, at-risk compensation program in this case?

A. Based upon our understanding of the markets in which we compete for employees as well as the advice of recognized third-party compensation consultants, Gulf needs the long-term at-risk compensation program to be market competitive. Other utilities and other major employers with whom we compete for employees use such programs. Gulf would be at a competitive disadvantage in attracting, engaging, retaining, and motivating employees if we did not offer comparable programs.

Compensation competitiveness aside, this is a highly effective element to attract, engage, retain, and motivate this group of employees, who have more impact on customer service and satisfaction than any other employees. A real advantage of an at-risk compensation program that has elements of both short-term and long-term financial performance goals is that it does not drive employees to make short-term economic decisions that have potential adverse long-term economic consequences. Driving employees to cut costs in the short-term may increase costs that customers will have to pay in the long term. That is why having an element of long-term at-risk compensation that focuses on financial performance benefits customers. Losing that element of compensation, particularly the employees who make both short-term and long-term decisions, is not in the customers' interests.

IV. TOTAL BENEFITS

Q. Turning to the benefits portion of Gulf's total compensation and benefits package, what is Gulf's approach for designing its employee benefits program?

A. The benefits program is an integral portion of our total compensation and benefits package. Similar to our compensation program, Gulf's benefits program is designed to align with our fundamental beliefs, specifically our beliefs that long-term value to the customer is created through retaining employees, that the health and well-being of the workforce makes a difference to productivity and customer satisfaction, and maintaining program competitiveness is critical to attract, engage, retain, and motivate our workforce. Like our compensation program, we annually go through a rigorous review of our benefits program to ensure that we are offering a competitive, but cost-efficient, benefit program to help us attract and retain our highly skilled workforce. Our benefits program, including retirement and welfare plans, is designed to be valued at the median of the external market. We have intentionally designed a flexible benefits program that allows employees to choose those benefits that meet their individual needs. This approach provides the advantage of having the cost of many of the programs shared between the Company and our employees.

Q. What are Gulf's projected benefit costs for the test year?

A. Based on the calculations available at the time the 2016 budget was finalized, total benefit costs were projected to be $36,971,542 in 2017. The components are:

Health and Welfare benefits		$ 14,255,244
Retirement Benefits		
Pension Plan	$ 2,810,000	
Post-employment benefits	$ 2,943,049	
Employee Savings Plan	$ 4,737,653	
Total Retirement Benefits		$ 10,490,702
Benefits Required by Law		$ 9,953,058
Other Benefits		$ 2,272,538

Benefits required by law include social security tax, federal and state unemployment taxes, and worker's compensation. The benefit costs projected in O&M for the rate case under the 2016 budget are $18,476,003.

Q. Have any of the benefit cost projections for 2017 materially changed since the 2016 budget was prepared?

A. Yes. Market conditions, specifically lower discount rates, have reduced the funded status of the pension plan, resulting in increased cost projections for the plan. To mitigate the cost increases and thereby lower the overall costs of the plan for our customers, Gulf will make a contribution to the pension plan in December 2016. The planned contribution is $81,000,000, which consists of $71,500,000 to improve the funded status for Gulf with the remaining $9,500,000 being Gulf's allocated portion for SCS resources.

This contribution will reduce expected pension O&M costs for the 2017 test year by $665,000, for a total pension O&M cost of $2,145,000. Ms. Ritenour makes adjustments to working capital and pension expense to reflect this additional pension contribution.

Q. In addition to the December 2016 contribution to the pension plan, is Gulf making other efforts to reduce the costs of the pension plan?

A. Yes. As with all of our benefit programs, we continually evaluate our pension plan for cost effectiveness and market competitiveness. Since Gulf's 2014 test year rate case, the primary changes to the pension plan are that employees hired on or after January 1, 2016, will have a single, reduced pension formula with accredited service capped at 30 years. These changes will reduce the growth in pension liability for the Company going forward.

Q. Why does Gulf provide a pension plan benefit for employees?

A. Gulf provides a pension plan benefit so that our benefits program will remain competitive in the market for new hires and to retain our highly skilled workforce and the investment we have made in training our employees. The pension plan is an economically efficient way to provide a retirement benefit which allows us to attract and retain the talent needed to provide the reliable and efficient service our customers expect and deserve.

Q. How does Gulf’s benefits program compare to the external market?

A. We performed an assessment and found Gulf’s benefits program to be competitive against the utility industry. Willis Towers Watson and Aon Hewitt conducted analyses of the benefit programs offered by Gulf and comparator companies in 2015, as can be seen in Exhibit JMG-1, Schedules 4 and 5, respectively. The analyses were done using Aon Hewitt's Benefit Index® and Willis Towers Watson’s BENVAL database surveys. These tools compare the relative worth of one company's benefits program to those offered by a group of other companies. Based on both the Aon Hewitt and Willis Towers Watson assessments, the relative value of benefits Gulf provides its employees is at market.

Q. How were the benefit competitiveness assessments made?

A. The analyses performed by Aon Hewitt and Willis Towers Watson utilize survey data to gauge the value of our benefits against other utilities. The surveys include all retirement income, death, disability, healthcare, and paid time off benefits offered to salaried hires. The actuarial value of each of the benefits is calculated to reflect what each program would be expected to pay during a year and the present value of the benefits new hires 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 surveys. 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.

Q. Please describe the relative value of Gulf's benefits program as compared to the external market as found by Willis Towers Watson and Aon Hewitt.

A. Exhibit JMG-1, Schedule 4 contains a chart showing Willis Towers Watson's analysis of the relative value of Gulf's benefits versus the average of two comparator groups. In addition, the chart shows the distribution of the relative values of comparator companies around the average. Exhibit JMG-1, Schedule 5 illustrates the relative value analysis completed by Aon Hewitt. Using Willis Towers Watson's BENVAL, Gulf's benefits program is 94.7 percent of the average value of benefits provided by other utilities. Using Aon Hewitt's Benefit Index, Gulf's benefits program is 102.7 percent of the average value of benefits provided by other utilities.

Q. Are Gulf's 2017 total benefit costs of $36,971,542 and projected O&M benefits expenses of $18,476,003 reasonable and prudent?

A. Yes. The benefit costs of Gulf's total compensation and benefits package is 17 percent lower than the cost in Gulf's 2014 test year rate case. The costs are reasonable and prudent and are necessary to continue our efforts to attract, engage, retain, and motivate qualified employees with a focus on customer service.

V. SUMMARY

Q. Please summarize your testimony.

A. Gulf's total compensation and benefits package benefits our customers by allowing us to attract, engage, retain and motivate a highly trained, skilled, and customer-focused workforce that delivers safe and reliable electric service. The design of our total compensation and benefit programs, including both short-term and long-term at-risk pay, is aligned with the median of the market. The costs of our compensation and benefit programs are both reasonable and prudent based on market comparisons and should be included in the rates paid by customers.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

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

Q. Please state your name and business address.

A. My name is Jan Hodnett. 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). I serve as Gulf's Comptroller.

Q. What are your responsibilities as Gulf's Comptroller?

A. I am responsible for the financial and regulatory accounting functions of the Company. My duties include maintaining Gulf's corporate accounting records in accordance with U.S. generally accepted accounting principles (GAAP) and in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the Florida Public Service Commission (FPSC or Commission). I have responsibility for the preparation of Gulf's financial statements and various financial reports required by the U.S. Securities and Exchange Commission, the FERC and the FPSC.

Q. Please state your prior work experience and responsibilities.

A. I began my career at Southern Company in 1980 at Gulf Power as an accountant. Since then, I have taken on roles of increasing responsibility, including Manager of Financial Accounting and Reporting for Georgia Power and Accounting Director and Assistant Comptroller for Southern Company Services, where I was responsible for Accounting Policy and Research and later SEC Reporting. I was named to my current role, Comptroller of Gulf, in June 2014.

Q. What is your educational background and professional certification?

A. I graduated from the University of West Florida in 1980 with a Bachelor of Accountancy degree and in 1987 with a Master of Business Administration. I am a licensed Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Florida Institute of Certified Public Accountants.

Q. What is the purpose of your testimony?

A. My testimony (a) sets forth and supports Gulf's 2017 Operations & Maintenance (O&M) expense budget within the Administrative & General (A&G) function, (b) justifies Gulf's 2017 A&G benchmark variance for O&M expenses, (c) supports the need to increase Gulf's annual property damage accrual for the property damage reserve, (d) addresses the appropriate level of rate case expense and Directors and Officers (D&O) liability insurance expense that should be allowed, (e) supports the changes in depreciation and dismantlement expense and the disposition of the Other

Cost of Removal regulatory asset in the test year, (f) explains the costs from Southern Company Services and other affiliate transactions, and (g) discusses income tax expense included in the test year.

Q. Are you relying on any independent studies performed in the regular course of business?

A. Yes. Third party studies performed by recognized experts are commonly used and relied upon by accounting experts to make accounting judgments. I am relying on the results of a Depreciation Study prepared by Gulf Witness Watson, who is employed by Alliance Consulting; a Dismantlement Study prepared by Southern Company Services; and the Transmission and Distribution Hurricane Loss and Reserve Performance Analyses (Storm Study) prepared by Gulf Witness Harris, who is employed by CoreLogic.

These studies were commissioned by Gulf in order to fulfill its obligations under mandates of the Commission. Commission Order No. PSC-13-0670-S-EI, Docket No. 130140-EI approving Gulf's Stipulation and Settlement Agreement (2013 Settlement Agreement or Settlement) stated that the Company shall file depreciation and dismantlement studies on or before December 31, 2018 or within a period not more than one year nor less than 60 days before Gulf's next general rate proceeding, whichever is sooner. Commission Rule 25-6.0143 requires Gulf to file a Storm Damage Self-Insurance Reserve Study at least once every five years.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit JJH-1, Schedules 1 through 6. Exhibit JJH-1 was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge and belief.

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

A. Yes. The MFRs that I sponsor or co-sponsor are listed on Schedule 1 of Exhibit JJH-1. The information contained in the MFRs I sponsor or co-sponsor is true and correct to the best of my knowledge and belief.

Q. How are the Company's accounting records maintained?

A. Gulf maintains its books and records in accordance with GAAP and the rules and regulations prescribed for public utilities in the Uniform System of Accounts published by the FERC and adopted by the FPSC.

I. ADMINISTRATIVE AND GENERAL EXPENSES

Q. What is Gulf's A&G O&M expense budget for the 2017 test year?

A. Gulf projects an O&M expense level for the A&G function of $89,348,000 in the test year.

Q. Is Gulf's projected level of A&G expenses of $89,348,000 in 2017 reasonable and prudent?

A. Yes. The projected level of A&G expenses is both reasonable and prudent. Gulf's 2017 A&G expenses are based on the extensive budget preparation and review process that each planning unit follows as discussed by Gulf Witness Mason. This process ensures that every item included in the budget is based upon the most accurate and up-to-date assumptions and reflects the reasonable needs of each unit to fulfill its business function.

The A&G expense budget consists of a wide range of corporate expenses that are not associated with any particular operating function. There are a number of planning units within the A&G function. Some of these include Accounting, Finance, Treasury, Human Resources, Information Technology, External Affairs, Supply Chain, and Corporate Services. Each planning unit within the A&G function is responsible for developing budgets for employees as well as office supplies and expenses within its unit. The remaining A&G expenses (insurance, employee benefits, and other miscellaneous expenses) are budgeted at a corporate level using the latest assumptions for the projected period.

Q. Is Gulf's projected level of A&G expenses of $89,348,000 in 2017 representative of a going forward level of A&G expense beyond 2017?

A. As noted above and discussed by Mr. Mason, the Company's budget process is very thorough, and O&M projections are prepared at a detailed level for a five year period. Schedule 2 of Exhibit JJH-1 compares total

A&G expenses, including the net operating income (NOI) adjustments, for the 2017 test year with the projections for the three years 2018 through 2020. A&G expenses identified in the budget process for 2017 are lower than projected A&G expenses for the years 2018 through 2020.

Q. How does Gulf's 2017 A&G expense forecast compare to the A&G expense benchmark calculation historically employed by the Commission?

A. The A&G benchmark is $84,154,000. This calculation is described in Gulf Witness Ritenour's testimony. Gulf's projected 2017 A&G expenses are $89,348,000. These A&G expenses exceed the A&G benchmark by $5,194,000. These values are shown on Exhibit JJH-1, Schedule 3.

Q. What is the driver of this $5,194,000 benchmark variance?

A. There are two primary drivers. The first driver is the requested increase in the annual accrual to the property damage reserve. In Section II of my testimony, I provide justification for the annual property damage reserve accrual increase to $8,900,000.

The second driver is the rededication of a portion of Plant Scherer Unit 3 to serve native load customers. No A&G expenses associated with Scherer Unit 3 were reflected in the 2012 allowed O&M expenses in Gulf's 2012 test year rate case as Scherer Unit 3 was devoted to wholesale sales. However, in the 2017 test year, a portion of Scherer Unit 3 has been rededicated to native load customers, so the A&G expenses associated with the portion of Scherer Unit 3 not currently committed to off-system sales are included in the test year. A&G expenses associated with the rededicated portion of Scherer Unit 3 in 2017 are $1,875,000.

II. PROPERTY DAMAGE ACCRUAL & RESERVE

Q. What is the property damage reserve designed to cover?

A. Per Commission Rule 25-6.0143, this account is established to provide for losses caused by accident, fire, flood, storms and similar type hazards to the utility's own property or property leased from others, which are not covered by insurance. This account would also include provisions for the deductible amounts contained in property loss insurance policies held by the utility.

Q. How does this reserve benefit Gulf's customers?

A. Building an adequate reserve over time helps reduce the risk that our customers may be required to pay a surcharge, or minimizes the amount of any surcharges to customers, at a time when our customers may be dealing with personal losses to their own property. Also, since the property damage reserve is partially funded, it helps ensure that Gulf has the financial resources when needed to quickly restore our customers' power after a severe weather event or accident, since existing financial resources are also used to support normal operations.

Q. Is the current reserve amount of $39,500,000 as of August 31, 2016, adequate?

A. No. Even with five years of virtually no hurricane related losses hitting the reserve, the reserve is approximately $8,000,000 below the bottom of the current target reserve range of $48 to $55 million set by the Commission in Gulf's 2012 test year rate case. If Gulf is to achieve the reserve balance the Commission previously determined five years ago was necessary to protect Gulf's customers, then the annual accrual has to be increased.

Q. Why has the Company been unable to achieve the current target reserve range set by the Commission?

A. Since 2011, the Company has recorded approximately $5.8 million in non-hurricane losses to the reserve. As shown in Exhibit JJH-1, Schedule 4, these events have included losses due to flooding, tropical storms, tornadoes and thunderstorms. In addition, the annual accrual to the reserve has not been increased since 1996.

As stated by the Commission in Order No. PSC-12-0179-FOF-EI, issued on April 3, 2012 in Docket No. 110138-EI, the target reserves need to be sufficient to cover most but not all storms, and also an additional amount for other property damage occurrences such as fires or other natural occurrences. At the current accrual rate, the Company would have to go three years with no charges to the property damage reserve to even reach the bottom of the current target reserve range set by the Commission.

Q. If the annual accrual established in 1996 was adjusted for CPI and customer growth, what would that accrual become in 2017?

A. The current annual accrual of $3,500,000 was set in 1996, 20 years ago, and has not been adjusted for the increase in property replacement values. If the accrual amount set in 1996 was adjusted for CPI and customer growth, it would now be approximately $7,711,000, more than double the current annual accrual.

Q. In Gulf's 2012 test year rate case, the Commission stated that no pressing need had been identified to warrant an increase in the accrual at that time, but the Commission also stated that if circumstances changed, it would be appropriate to revisit the decision in a future proceeding. What circumstances have changed that warrant the Commission revisiting the annual property damage accrual?

A. Several things have occurred that justify increasing the annual accrual:

- The replacement value of uninsured overhead distribution and transmission (T&D) assets included in storm studies has grown from $1.6 billion in Gulf's 2011 Storm Study to $2.3 billion in the 2016 Storm Study, a 43 percent increase in uninsured property replacement value.
- The replacement value of T&D assets in the 2016 Storm Study is based on plant-in-service balances as of year-end 2014. The study does not include net T&D investment of $247 million that has been placed in service in 2015 and 2016.
- The Company has charged approximately $5.8 million to the property damage reserve since 2011 for non-hurricane property losses.

Q. Are there other factors that should be considered?

A. Yes. The Company's deductible levels for damage to insured property are $25 million for wind, wind driven rain and storm surge caused by "Named Windstorm", and $10 million for other insured property damage occurrences. These large deductibles are charged against the reserve for Company owned property that is insured from property loss.

Q. By what amount is Gulf requesting an increase in the annual property damage accrual in this case?

A. To help ensure the Company builds an adequate reserve, Gulf has included a property damage accrual of $8,900,000 in the 2017 test year. This results in an NOI adjustment of $5,400,000 for the test year as discussed in Ms. Ritenour's testimony.

Q. Please explain the increase over the current approved annual accrual amount.

A. The annual accrual of $8,900,000 is based on the expected average annual hurricane loss (EAD) charged to the reserve of $7,900,000 and an additional annual amount of $1,000,000 for non-hurricane property losses. The $7,900,000 is based on Gulf's 2016 Storm Study filed with the Commission. As shown on Exhibit JJH-1, Schedule 4, the $1,000,000 is based on an annual average of non-hurricane property damage losses since Gulf's 2012 test year rate case, which is when the Commission acknowledged that charges are made against the reserve for items other than storms.

Q. Please explain why customers today should pay to build an adequate reserve that would be used in the future?

A. In addition to the customer benefits I discussed previously, commercial insurance is not cost beneficial to cover T&D assets, and therefore the Company is self-insured for T&D property losses.

No customer or group of customers receiving service at the time of the loss should be burdened with all the costs of a hurricane or other property loss event. Previous customers should have paid their share of the loss, because the risk was there every year. Protecting against losses that we know will occur but which we cannot predict with precision as to exact time is simply a cost of providing electric service that all customers should pay regardless of whether they have the misfortune of experiencing a hurricane, tornado, flood or other property loss event.

Q. How would Gulf's requested $5,400,000 increase in the annual accrual to the property damage reserve affect a residential customer?

A. It would increase a residential bill by $0.49 for customers using 1,000 kWh per month. More importantly, it protects our customers in the event of a property damage event by a) assuring funds are immediately available for restoration of service and b) helping to reduce any negative impact a property damage event may have on the financial integrity of the Company if the Company is required to access the debt and capital markets for restoration of service to our customers.

III. RATE CASE EXPENSE

Q. Please explain how the estimated rate case expense for the 2017 test year rate case was calculated.

A. Gulf's recent rate case experience shows that the cost of a rate case continues to increase due to more discovery and new topics as part of a rate case. To address these additional demands, Gulf anticipates incurring more expense for discovery, incremental labor resources, additional outside consulting and legal fees.

The Company estimates rate case expense for its 2017 test year rate case to be $6,700,000. This amount was calculated by taking the actual rate case expense incurred in Gulf's 2014 test year rate case, $4,100,000, and adding an additional amount for attorney resources and hearings, which were not held in Gulf’s 2014 test year rate case.

The increased rate case expense results in a NOI adjustment of $1,673,000 in the 2017 test year. This NOI adjustment is discussed in Ms. Ritenour's testimony.

IV. DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. Should the Commission allow the Company's test year expense for Directors and Officers (D&O) liability insurance?

A. Yes. The $119,000 premium paid by Gulf for D&O liability insurance directly benefits customers and is a necessary and reasonable expense for the Company to do business.

Q. How do customers benefit from D&O liability insurance?

A. Gulf must have competent and skilled directors and officers to lead it. Our customers benefit from the proper oversight and management provided by our directors and officers. These individuals would be difficult to attract and retain if the Company did not maintain D&O liability insurance. Additionally, D&O liability insurance helps protect the assets of the Company, which are used to serve Gulf's customers. D&O liability insurance is a legitimate and necessary cost of providing service to our customers.

Q. Please provide a brief summary of the Commission's approach in Gulf's 2012 test year rate case related to D&O liability insurance.

A. In Gulf's 2012 test year rate case, the Commission agreed with Gulf that D&O liability insurance is prudent and necessary for a publicly held company to have, and that it ensures the Company will be able to attract and retain skilled leadership. However, the Commission felt that both shareholders and customers receive benefits from D&O liability insurance and the associated cost should be shared equally between the shareholders and the customers.

Q. Does Gulf's request for $119,000 of D&O liability premiums include premiums related to protection of Southern Company shareholders?

A. No. D&O liability premiums are negotiated at a Southern Company level, which helps ensure the best possible premium cost for D&O liability coverage. The premiums are then allocated to Southern Company and the subsidiary companies. Southern allocates approximately 48 percent of the premiums to Southern Company as a cost to the shareholders. The remaining 52 percent of the premiums are allocated to the subsidiary companies, which includes Gulf. The $119,000 in Gulf's test year represents the premiums allocated to Gulf D&O liability coverage only for Gulf's Directors and Officers, which benefit Gulf's customers.

Q. Do Gulf customers benefit from allowing Southern Company to negotiate D&O liability premiums at a Southern Company level versus Gulf obtaining a stand-alone D&O liability insurance policy?

A. Yes. If Gulf had to procure its own D&O liability insurance policy, a stand-alone policy is estimated to cost approximately $600,000 annually based on the asset size of Gulf and the level of coverage normally requested for companies the size of Gulf. Therefore, the entire requested amount of $119,000 should be allowed as a 2017 test year expense.

V. DEPRECIATION

Q. What is the basis for Gulf's depreciation expense in 2017?

A. Gulf's depreciation expense reflects the depreciation rates approved by the Commission in Order No. PSC-10-0458-PAA-EI, issued on July 19, 2010 in Docket No. 090319-EI; the depreciation rate for the Perdido Landfill Facility approved by the Commission in Order No. PSC-10-0674- PAA-El, issued on November 9, 2010 in Docket No. 100368-EI; and the depreciation rate for the Advanced Metering Infrastructure meters approved by the Commission in Order No. PSC-12-0179-FOF-EI, issued on April 3, 2012 in Docket No. 110138-EI. In accordance with Gulf’s 2013 Settlement Agreement in Docket No. 130140-EI, Gulf filed a new depreciation study with the Commission on July 14, 2016 and a corrected study (the Depreciation Study) on September 20, 2016. The Depreciation Study is sponsored by Gulf Witness Watson as Exhibit DAW-1, and the Company has made a NOI adjustment of $12,479,000 to the 2017 test year to reflect an increase in depreciation expense based on the results of the Depreciation Study. The proposed increase is primarily due to additional investment, interim retirements and interim net salvage estimates. A reconciliation of total depreciation expense in Gulf's 2017 test year to the calculated expense based on the proposed rates in Gulf's Depreciation Study can be found on Exhibit JJH-1, Schedule 5.

Q. What is the basis for the plant balances used in Gulf's Depreciation Study?

A. The Depreciation Study's analysis is based on projected plant and reserve balances as of December 31, 2016. The results of these analyses are then applied to estimated balances through the end of 2017. The composite depreciation rates, which are based on the Depreciation Study, are used to calculate the Company adjustment to the 2017 test year. Further assumptions and details of the Depreciation Study are discussed in Mr. Watson's testimony.

Q. Has the Commission approved Gulf's 2016 Depreciation Study?

A. Not at this time. The Company asks that the final outcome of the FPSC's review and approval of the Depreciation Study be reflected in the 2017 test year expenses used as the basis for setting rates in this docket.

Q. What should be the effective date of the proposed rates in Gulf's 2016 Depreciation Study?

A. The Company asks that the effective date of the proposed rates in the Depreciation Study coincide with the effective date of base rates set in this docket.

Q. Is Gulf requesting authority for any depreciation rates that are not included in Gulf's 2016 Depreciation Study?

A. Yes. As addressed by Gulf Witness Terry, to meet needs expressed by customers who have an interest in electric vehicles, Gulf is seeking a depreciation rate for electric vehicle chargers to allow us to purchase, install and support these devices at customers' locations, behind their electric service meter. Gulf is requesting authority to use a 15 year life for electric vehicle charging infrastructure and a net salvage of 0 percent for electric vehicle charging infrastructure charged to FERC account 371.

Q. What is the basis for requesting a 15 year service life for electric vehicle charging infrastructure?

A. Electric vehicle charging infrastructure is a relatively new equipment type. Depreciable life recommendations from manufactures vary. Gulf assumes a 15 year life based upon a reasonable range derived from manufacturers' recommendations and industry studies. Because this equipment is relatively new, Gulf is not aware of any industry consensus on the useful life of these assets.

Q. Why was this requested rate not included in the 2016 Depreciation Study?

A. The 2016 Depreciation Study is based on projected plant and reserve balances as of December 31, 2016. There was no investment in electric vehicle charging infrastructure at the end of 2016.

Q. When does the Company expect to have investment in electric vehicle charging infrastructure?

A. The Company expects to spend approximately $417,000 for electric vehicle charging infrastructure in 2017.

VI. DISMANTLEMENT

Q. What is the basis for Gulf's dismantlement expense in 2017?

A. Gulf's dismantlement expense reflects the dismantlement amounts approved by the Commission in Order No. PSC-10-0458-PAA-EI, issued on July 19, 2010 in Docket No. 090319-EI. In accordance with Gulf's 2013 Settlement Agreement in Docket No. 130140-EI, Gulf filed a new dismantlement study with the Commission on July 14, 2016. The Dismantlement Study is Exhibit JJH-1, Schedule 6, and the Company has made a NOI adjustment of $5,188,000 to the 2017 test year (which reduces the annual dismantlement accrual in base rates to zero) to reflect a decrease in dismantlement expense based on the results of the Dismantlement Study. A reconciliation of total dismantlement expense in Gulf's 2017 test year to the calculated expense based on the proposed rates in Gulf's 2017 Dismantlement Study can be found on Exhibit JJH-1, Schedule 5.

Q. Please describe any adjustments to Gulf's accumulated dismantlement reserves as a result of Gulf's 2016 Dismantlement Study.

A. As discussed in Gulf's 2016 Dismantlement Study filing, the Company's Dismantlement Study showed a base rate surplus in accumulated dismantlement reserves.

As part of the Company's 2013 Settlement Agreement, the Commission gave Gulf the authority to record retail jurisdictional credits to depreciation expense of up to $62.5 million over the life of the Agreement with an offsetting entry to a regulatory asset referred to as Other Cost of Removal. Over the course of the Settlement period, Gulf will have recorded $62.5 million to this regulatory asset account. It was the intent of the parties involved in the Settlement that the Other Cost of Removal regulatory asset be considered and accounted for in conjunction with the accumulated aggregate balances in the reserve for cost of removal and the reserve for fossil generating plant dismantlement when the Commission next established depreciation rates and dismantlement accruals on a going-forward basis.

In accordance with the Settlement, Gulf offset the $62,500,000 Other Cost of Removal regulatory asset against the reserve accumulated for fossil generating plant dismantlement, thereby eliminating the Other Cost of Removal regulatory asset and reducing the accumulated reserve for fossil-fired generating plant dismantlement of base rate assets by the same amount.

Q. Has the FPSC approved Gulf's 2016 Dismantlement Study?

A. Not at this time. The study results are based on Gulf's projected plant in service and incorporate the latest disposal, removal and salvage pricing. The Company asks that the final outcome of the FPSC's review and approval of the Dismantlement Study be reflected in the 2017 test year expenses used as the basis for setting rates in this docket.

Q. What should be the effective date of the proposed annual accruals in Gulf's 2016 Dismantlement Study?

A. The Company asks that the effective date of the proposed rates in the Dismantlement Study coincide with the effective date of base rates set in this docket.

Q. What is the net effect of the depreciation and dismantlement studies?

A. Gulf's combined annual expense for depreciation and dismantlement would increase by $7,291,000 based on the proposed change in depreciation rates and the annual dismantlement accrual amounts. This net adjustment is shown on Schedule 4, page 3 of Ms. Ritenour's testimony.

VII. SOUTHERN COMPANY SERVICES

Q. Please provide an overview of SCS and its relationship to Gulf.

A. SCS is a subsidiary of Southern Company that 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 to Gulf by SCS are provided at cost with no profit mark-up. Costs to Gulf from SCS are determined and billed in two ways. When direct assignment of a cost is possible, SCS bills Gulf for the cost of the particular service rendered. 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 by Gulf and accepted by the Commission in Gulf's 2012 test year 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. How often are the service company allocation factors updated?

A. The allocation factors are typically recalculated once a year based upon the prior year's actual data, and the updated factors are used to develop the budget amounts and subsequently to bill the actual costs for the following year. For example, the 2016 budget allocators used in this case were updated in 2015 based upon the 2014 actual data.

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

A. Gulf and its customers receive several benefits. The existence of SCS facilitates the economic dispatch and sharing of generation resources, avoids duplication of personnel in the various operating companies due to the provision of numerous services to the operating companies, provides economies of scale in purchasing (such as bulk purchasing leverage) 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 additional professional and technical personnel who might not be fully utilized on a continuous basis. The benefits received by Gulf include, but are not limited to, the following: SCS administers the Intercompany Interchange Contract and coordinates the economic dispatch of the Southern System generating resources to minimize the energy costs to our customers; SCS negotiates system-wide purchase agreements with vendors to maximize volume procurement savings for our customers; Gulf utilizes SCS engineering for the planning, design, and project management related to large generation and transmission projects; SCS prepares Gulf's dismantlement study and SCS manages the centralized filing of income tax returns and provides review, instructions and guidance to the subsidiaries to ensure compliance with IRS regulations and requirements.

All these services are provided to Gulf at cost. If Gulf used third party providers to provide these services, such providers would charge more than their cost to derive a profit on the provision of their services. Using SCS for these services avoids that additional payment. Similarly, if Gulf had to add in-house employees to provide these services, its overall employee count would escalate, and Gulf would have to incur additional compensation and benefits that are currently shared by multiple Operating Companies. This cost sharing arrangement reduces the overall cost of providing service to Gulf's customers.

Q. Are there other affiliate transactions included in your test year amounts?

A. Yes. As noted in MFR C-30, Gulf has included other utility related transactions with Southern Company affiliates. All affiliate transactions are for utility services such as production plant joint ownership billings, transmission facility services, material transfers, and storm restoration assistance. These transactions benefit our customers by enabling Gulf to receive needed materials and services at cost from the other affiliates and they are accounted for in accordance with Rule 25-6.1351, Florida Administrative Code.

VIII. OTHER NOI ADJUSTMENTS

Q. Are there any NOI adjustments in your area of responsibility besides the ones you have previously discussed in your testimony?

A. Yes. To correct an error in the calculation of the amount of miscellaneous service revenues included in the test year, an NOI adjustment was made to increase the amount of miscellaneous service revenues in the test year by $1,184,000.

IX. INCOME TAX EXPENSE

Q. What amount of income tax expense is included for the 2017 test year?

A. The total federal and state income tax provision for the test year is $69,375,000 as shown on MFR C-22.

Q. How was this amount calculated?

A. The income tax expense was calculated in accordance with GAAP and is consistent with the way income tax expense was calculated and approved by the Commission in the 2012 test year rate case.

X. SUMMARY

Q. Please summarize your testimony.

A. The level of A&G costs requested in this case is reasonable, prudent and necessary to enable Gulf to continue to provide high quality, reliable electric service to our customers. Although the costs exceed the O&M benchmark, the variance is fully justified by a necessary increase in the property damage reserve accrual designed to protect customers when they are most vulnerable and the rededication of a portion of Scherer Unit 3 to serve native load customers.

Gulf's requested property damage accrual is an appropriate amount that serves the interests of our customers in accordance with established

Commission policy. The property damage reserve accrual needs to be increased to protect customers by achieving the existing target reserve range, mitigating potential storm surcharges and providing funds for immediate restoration activities.

Also, I have justified why the requested amounts of rate case expense and D&O liability insurance expense should be allowed.
The requested levels of depreciation, amortization and dismantlement expense are reasonable, prudent and necessary. The other cost of removal regulatory asset has been applied to reduce the surplus in the existing dismantlement reserve.

I have explained the costs from Southern Company Services and other affiliate transactions and the test year income tax expense has been calculated appropriately.

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

(Transcript continues in sequence with Volume 3.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney, or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 22nd day of March, 2017.

Linda Boles

LINDA BOLES, CRR, RPR
Official FPSC Hearings Reporter
Office of Commission Clerk
(850)413-6734