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GULF POWER
A SOUTHERN COMPANY

November 6, 2013

Ms. Ann Cole, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0850

VIA HAND DELIVERY

RE: Docket No. 130140-EI

Dear Ms. Cole:

Enclosed for official filing on behalf of Gulf Power Company (Gulf) in the above referenced docket are an original and fifteen (15) copies of the Rebuttal Testimony and Exhibits of the following Gulf Witnesses:

Rhonda J. Alexander
Jeffrey A. Burleson
Michael L. Burroughs
P. Chris Caldwell
J. Terry Deason
Steven M. Fetter
James M. Garvie
Raymond W. Grove
Peter S. Huck
Richard J. McMillan
Susan D. Ritenour
Angela G. Strickland
R. Scott Teel
James H. Vander Weide, Ph.D
Amy D. Whaley

Original affidavits for each witness' testimony will be submitted under separate cover at a later date.

Sincerely,

Robert L. McGee, Jr.

Robert L. McGee, Jr.

md

Enclosures

cc: Beggs & Lane
Jeffrey A. Stone, Esq.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition for Increase in Rates)
By Gulf Power Company)
) Docket No.: 130140-EI

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing has been furnished by hand delivery this 6th day of November, 2013 to the following parties:

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And via overnight delivery this 6th day of November, 2013 to the following party:

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

RHONDA J. ALEXANDER

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Rhonda J. Alexander
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Rhonda Alexander. My business address is One Energy Place, Pensacola Florida, 32520 and I am the Supervisor of Forecasting for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the inappropriate methods and erroneous conclusions reached by Federal Executive Agencies (FEA) Witness Greg R. Meyer and Office of Public Counsel (OPC) Witness Mark E. Garrett regarding Gulf's forecast. I will show that Gulf's forecast is appropriate for the Commission to use in setting base rates in this proceeding and is based on sound and unbiased methodology.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes. I am sponsoring Exhibit RJA-2, consisting of one schedule. Exhibit RJA-2 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. Is Mr. Meyer's conclusion regarding Gulf's forecast of residential usage per customer correct?

A. No. Mr. Meyer erroneously concludes in his testimony that Gulf did not incorporate the expectation of economic recovery in its 2014 residential energy forecast and that Gulf's forecast of residential kilowatt hour (kWh) use per customer in the test year is therefore understated. [Meyer at 4 through 6] He is mistaken because Gulf's residential energy sales model does show that forecasted residential kWh use per customer per billing day is higher based on the expectation of economic recovery through higher income growth projected. As is clearly shown in the Company's MFR Schedule F-7 pages 11 and 12, the values reported for real disposable income per household, an independent variable used in the Company's residential energy sales model, are higher for the period May through December 2014 compared to the same period in 2013. The observed lower residential usage in the May through December 2014 timeframe is being driven primarily by price elasticity impacts.

Q. In addition to the independent variable of real disposable income per household, what are the other independent variables used in Gulf's residential energy sales model that drive changes in kWh use per customer per billing day?

A. As described in my direct testimony, in addition to an independent variable for real disposable income per household, Gulf's residential energy sales model includes variables for weather and residential electricity price.

Q. Please explain how each of the independent variables impacted Gulf's forecast of residential kWh use per customer per billing day for May through December 2014 as compared to the same period in 2013.

A. As mentioned previously, the impact of growth in real disposable income per household on residential kWh use per customer per billing day was positive. There was no change in the values used for the weather variables between these two periods because both periods were based on the same "normal" weather assumption; therefore, weather did not cause a change in use per customer from 2013 to 2014. The impact of the change in the price decline index variable on kWh use per customer was slightly positive; however, the impact of the change in the price increase index was negative. Therefore, as a result of forecasted increases in residential electricity price, kWh use per customer per billing day is projected to decline during the period May through December 2014. The net impact of the changes in all of these independent variables is a decline in Gulf's forecasted residential kWh use per customer per billing day comparing May through December 2014 to the same period in 2013. Schedule 1 of my Exhibit RJA-2 includes a table summarizing the impacts of each independent variable on energy sales and base revenue.

Q. Is the basis for Mr. Meyer's proposed adjustment to forecasted residential revenues well founded?

A. No. Without the benefit of any meaningful analysis, Mr. Meyer simply suggests using the May through December 2013 customer usage amounts as a proxy for the forecasted 2014 levels in order to keep customer usage amounts equal for both periods. [Meyer at 5 and 6] Mr. Meyer fails to consider that customers also respond to price changes, which has been observed in Gulf's historical sales data. He uses no model or analytical process for arriving at his recommendation. As is common forecasting practice, Gulf's forecast models appropriately consider the impact on energy usage from changes in both economic and price variables.

Q. Did Mr. Meyer have the necessary data available to him to analyze the impacts of all independent variables on residential kWh use per customer?

A. Yes. In response to Item No. 16 of FEA's First Set of Interrogatories filed on October 14, 2013, Gulf provided the forecast assumptions used in the residential energy sales model. Included in Gulf's response is a file that contains the historical and predicted use per customer per billing day and a breakdown of how much each independent variable is contributing to the total use per customer.

Q. Is there another source for the data necessary to analyze the impact of each of the independent variables?

A. Yes. To calculate how much each independent variable is contributing to the total use per customer, one can simply multiply each independent variable's coefficient by the monthly values for each of the independent variables. The coefficients for the independent variables are shown on Schedule 3, Page 2, of Exhibit RJA-1 attached to my direct testimony. The monthly values for the independent variables are provided in Gulf's MFR Schedule F-7. Therefore, all parties to this case have had the necessary data to analyze the impact of Gulf's independent variables on residential kWh per customer since Gulf's filing in July 2013. Contrary to Mr. Meyer's erroneous conclusion in his testimony, Gulf has appropriately incorporated the expectation of economic recovery in its modeling of the 2014 residential energy forecast.

Q. Does OPC Witness Garrett have a sound argument for suggesting that the Commission should increase Gulf's projected residential revenues for 2014?

A. No. Mr. Garrett erroneously assumes in his testimony that Gulf took a "cautious approach" with its revenue forecast [Garrett at 60] and made an "effort to avoid overstating expected revenues." [Garrett at 61] Mr. Garrett apparently bases his claim solely on the fact that the Company over-forecasted energy sales for the 2012 test year in its last base rate proceeding and an acknowledgement in my direct testimony that the risk of economic uncertainty is higher now than has historically been the case.

Q. Did the Company take a cautious approach with its revenue forecast to avoid overstating expected revenues?

A. No. Gulf developed its forecast with an unbiased approach, using the same methodology that it has used for many years. As stated in my direct testimony on page 9 and 10, only minor refinements in Gulf's forecast methodology have been made over the years, with the fundamental methods remaining unchanged. In fact, Gulf's forecast methodology was used in the last base rate proceeding and was stipulated to by the parties and approved by the Commission. Mr. Garrett did not take this information into consideration when he made his unfounded presumption regarding Gulf's approach to the forecast. Despite the challenging economic conditions experienced over the past several years, Gulf's forecast methodology is fundamentally sound and is the most accurate tool available for forecasting the Company's future energy sales.

Q. How accurate have Gulf's retail energy sales and base revenue forecasts which have been proposed for use in this proceeding been?

A. Over the 11 months of the forecast period for which we have actual data to compare to the forecast (November 2012 through September 2013), total retail energy sales and base revenue were slightly over-forecast by 2.0 percent and 1.0 percent, respectively. (Over-forecast means Gulf forecast more energy than our customers actually purchased and more retail base revenue than we actually received over that time period.) Therefore, based on data available to date, Gulf's excellent forecast accuracy shows the strength in the Company's methodology and, furthermore, reflects a slight over-statement of revenue projections, not an under-statement as Mr. Garrett suggests.

Q. You mentioned previously that the Company acknowledges the higher risk of economic uncertainty that exists in today's market. Is there still a risk of economic uncertainty in Gulf's forecast of energy sales?

A. Yes. Recent events surrounding the U.S. debt ceiling suggest that there is greater uncertainty in the economy than was present when the forecast being used in this proceeding was developed. If economic recovery is negatively impacted as a result of these or other similar unexpected events, then Gulf's energy sales forecast would likely be overstated.

Q. Is an "annualization" adjustment to the forecast, as proposed by Mr. Garrett, appropriate?

A. No. Mr. Garrett claims that the Company "failed to include an appropriate test year end annualization in its forecast, which causes the Company's projected revenues to be understated." He applies a so-called "standard test year end annualization for the 2014 test year based upon the Company's projected customer count level for December 2014." [Garrett at 61] Mr. Garrett's characterization of his misguided adjustment as "standard" is incorrect. This is not a common practice for forecasting customers, energy sales, or revenues. Mr. Garrett's "annualization" adjustment is actually an unusual and unreasonable assumption that the number of customers Gulf expects at the end of the 2014 test year should be used as the customer count for all 12 months of the forecasted test year. Gulf has projected to add 5,052 residential customers over the period January through December 2014. Mr. Garrett's proposed adjustment assumes that these expected gains of over 5,000 customers for the entire year of 2014 all occur in the first month of the year, rather than spread across the months. This assumption is completely unsupported and does not reflect the reality of Gulf's business.

Q. Please describe the methodology Gulf used to forecast residential customers for the 2014 test year.

A. As described in my direct testimony, the short-term forecast of residential non-lighting customers was based primarily on input from Gulf's field Marketing Managers. These three managers, who each have over 30 years of experience with the Company, provide monthly customer gains projections taking into consideration many different factors such as historical trends, the local economy, the real estate market, planned neighborhood developments and construction projects, etc. These monthly customer gains projections at the district level are summed to derive the total company forecast of residential customers.

Q. Does Mr. Garrett provide any justification as to why his proposed "test year end annualization" method is better than using Gulf's monthly projections of customer count?

A. No. Gulf's very detailed monthly customer projections, supported by input from field managers, should not be ignored as Mr. Garrett suggests. Gulf uses these monthly customer forecasts to ensure a more precise calculation of projected energy sales and base revenue. This same customer forecast methodology has been used by the Company in all of its prior base rate proceedings at least as far back as Gulf's 1989 rate case and, in each of the three cases, was stipulated to by the parties and approved by the Commission.

Q. How accurate has Gulf's residential customer forecast which has been proposed for use in this proceeding been?

A. Over the 11 months of the forecast period for which we have actual data to compare to the forecast (November 2012 through September 2013), residential customers were minimally over-forecast by 0.1 percent. This excellent accuracy in Gulf's residential customer forecast shows the strength in the Company's methodology.

Q. Please summarize your testimony.

A. The proposed adjustments to Gulf's forecast of residential revenues made by Mr. Meyer and Mr. Garrett are inappropriate and should be rejected by this Commission. The arguments and claims of these witnesses are unsupported. Their suggested adjustments to Gulf's residential revenue forecast are based on inappropriate methods and erroneous conclusions regarding Gulf's forecast. Mr. Meyer incorrectly assumes that Gulf did not incorporate the expectation of economic recovery in its forecast and his proposed adjustment to residential revenue ignores the impact of forecasted electricity prices. Mr. Garrett's proposed "annualization" adjustment to residential revenue is an unusual and unreasonable assumption that Gulf's expected customer gains for the entire 2014 test year will all occur in the first month of the year and ignores the fact that Gulf has very detailed monthly projections of residential customers.

Gulf's forecast is based upon a methodology that is sound and unbiased. This methodology has been used by the Company for many years and continues to produce forecasts with a high level of accuracy. The Commission should accept Gulf's forecast of customers, kWh energy sales, billing demands, and base revenue proposed in this proceeding as appropriate for setting the Company's base rates.

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

Exhibit

Residential Energy Sales Model Impact of Independent Variables on Energy Sales and Base Revenue May-Dec 2014 Compared to May-Dec 2013		
Independent Variables	**Change in Energy Sales GWh**	**Change in Base Revenue $ in Millions**
Real Disposable Income per Household	37.6	$1.6
Weather	0.0	0.0
Price Decline Index	2.3	0.1
Price Increase Index	(81.8)	(3.5)
Total Change	(41.9)	$(1.8)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

JEFFREY A. BURLESON

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Jeffrey A. Burleson
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Jeff Burleson. My business address is 600 North 18th Street, Birmingham, AL 35203 and I am the System Planning Vice President for Southern Company Services (SCS).

Q. Please summarize your background and professional experience.

A. I have more than 30 years of experience in the electric utility industry. I began my career with Alabama Power Company in 1980 as a cooperative education student. I graduated from the University of Alabama at Birmingham in 1984 with a Bachelor of Science degree in Electrical Engineering, with a specialization in power systems analysis. From 1984 to 1991, I held various staff and managerial positions in the Technical Services and Power Quality departments at Alabama Power Company. During this period, I attended Auburn University and earned a Master of Science degree in Electrical Engineering in 1987, again, with a specialization in power systems analysis.

In 1991, I transferred to SCS in the position of Manager of End Use Technology Research, where my responsibilities included technology assessment, various types of load and economic modeling in support of integrated resource planning, and development of certain models used in integrated resource planning. In 1996, I was named Assistant to the Vice President of Marketing and New Business Development at SCS. In 1997, I was named General Manager of Marketing Services, where my responsibilities included oversight of the SCS analytical services associated with peak demand and long term energy forecasts, load research, cost of service studies, and competitive intelligence.

In 1999, I transferred to Georgia Power as Manager of Market Planning, where my responsibilities included the load, energy and revenue forecasts, economic evaluation of demand-side management programs and assessment of demand response from certain rate designs. In 2005, I was appointed Director of Resource Policy and Planning for Georgia Power where my responsibilities included integrated resource planning, resource procurement, generation development and administration and oversight of power purchase agreements.

In 2011, I was appointed Vice President of System Planning for SCS. My responsibilities include oversight of the analytical and planning services provided to the retail operating companies for integrated resource planning, transmission planning, reliability planning, resource procurement, generation strategy, generation development, and various economic viability analyses.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address the testimony of Office of Public Counsel (OPC) Witness Norwood. Specifically, I will address the comments he makes regarding how Gulf addressed the retirement of Plant Smith Units 1 and 2 as an option in Gulf's Mercury and Air Toxics Standards ("MATS") compliance strategy as well as his comments regarding Must-Run and the prudency of Gulf's proposed transmission upgrades to address compliance at Plants Crist and Smith. I will show that (a) Gulf analyzed, and continues to analyze, the possible early retirement of Plant Smith Units 1 and 2 as a MATS compliance option and (b) the transmission upgrades associated with Plant Crist and Plant Smith are necessary for cost-effective compliance with the EPA MATS rule and its short compliance window. I also address the impact the MATS rule has on Gulf's ability to comply with the North American Electric Reliability Corporation's ("NERC") Reliability Standards.

I will next discuss the various options for compliance with MATS that have been considered and how certain of these options have been eliminated from further consideration. For Plant Smith, there are two potential options remaining, both of which require the same transmission upgrades to comply with MATS and eliminate the Must-Run requirements currently associated with the two coal-fired generating units at that site. For Plant Crist, there is only one viable option remaining and that requires the proposed transmission upgrades necessary to comply with MATS and eliminate the Must-Run requirements currently applicable to generation at that site.

Lastly, I will show that the Must-Run analyses for the transmission upgrades for Plant Crist and Plant Smith are appropriate and utilize reasonable assumptions. Overall, my testimony will show that the transmission upgrades associated with MATS compliance at both Plant Crist and Plant Smith are necessary and prudent.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes, I am sponsoring Exhibit JAB-1 consisting of two schedules. Schedule 1 depicts Gulf's MATS compliance evaluation. Schedule 2 is a letter from the Florida Department of Environmental Protection ("FDEP") stating that from FDEP's perspective, installing or upgrading transmission lines is a valid option to comply with and meet the regulatory requirements of MATS. Schedule 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. The information contained in Schedule 2 is true and correct to the best of my knowledge and belief.

I. Transmission Upgrades are Necessary for the Only Two Remaining Viable MATS Compliance Options for the Plant Smith Coal Units

Q. Why are the proposed transmission upgrades associated with Plant Smith necessary and prudent to implement at this time?

A. As I will explain in the following pages of my testimony, Gulf's evaluation of

MATS compliance for Plant Smith has narrowed the options down to two remaining viable options. *The exact same transmission upgrades associated with Plant Smith are necessary for both of these two options*, as discussed in Gulf Witness Vick's Exhibit JOV-1, Gulf's Environmental Compliance Program Update page 23. Additionally, a set of transmission projects of this magnitude takes several years to complete once permitting is authorized and assuming the project is constructed on existing right of way.

Q. Summarize the process for the screening and evaluation of each of the options considered by Gulf in evaluating its MATS compliance strategy.

A. As with any decision that could lead to a number of possible outcomes, the options have undergone a screening and evaluation process that becomes increasingly rigorous as the number of options is narrowed. The screening and evaluation process includes both qualitative and quantitative steps. This process ensures that the most economic and reliable option for customers is selected when the final decision is made. Options that are not feasible, due to factors such as time constraints given the short MATS compliance window, have been excluded from further consideration as a part of the qualitative screening. Likewise, in the quantitative screening process, any option that is substantially less economic than at least one of the other remaining options is removed from further refinement and evaluation.

Q. Identify the primary MATS compliance options evaluated by Gulf for Plant Smith Units 1 and 2.

A. Gulf evaluated a wide array of options for MATS compliance for the Plant Smith coal units. The primary options included: 1) conversion of Plant Smith Units 1 and 2 from coal to gas, which I will refer to as "Gas Conversion", 2) retirement of Plant Smith Units 1 and 2 and replacement of that capacity, which I will refer to as "Retire & Replace", and 3) adding emission controls to Plant Smith Units 1 and 2 to comply with MATS, which I will refer to as "Add Controls". See my Schedule 1 of Exhibit JAB-1 for a simple flow diagram of the evaluation of options.

Q. Are there any secondary options associated with the primary MATS compliance options?

A. Yes, the primary options of "Retire & Replace" and "Add Controls" each have secondary options. For the "Retire & Replace" primary option, there are two secondary options: 1) "Retire & Replace On-Site", and 2) "Retire & Replace Off-Site". For the "Add Controls" primary option, there are also two secondary options: 1) "Add Controls using Scrubber", and 2) "Add Controls using Injection" (of sorbents). This "Add Controls using Injection" secondary option refers to the addition of activated carbon injection and dry sorbent injection along with some other changes to the Plant Smith coal units as described on page 23 of Exhibit JOV-1.

Q. Are there any tertiary options associated with any of the secondary MATS compliance options?

A. Yes, the option of "Add Controls using Injection" has two tertiary options: 1) "Add Controls using Injection with Transmission Upgrade" which eliminates the need for Must-Run operation, and 2) "Add Controls using Injection with Must-Run" which avoids the transmission upgrades but results in a significant amount of operation of the units in Must-Run status.

Q. Summarize the status of the evaluation of each of the aforementioned options.

A. Please refer to Exhibit JAB-1, Schedule 1 for a simple flow diagram of the following explanation. The option of "Gas Conversion" has been eliminated from further evaluation due to the high cost of adding additional firm natural gas transportation for Plant Smith coupled with the relative inefficiency of burning gas in a steam boiler designed for coal-fired production of electricity.

The option of "Retire & Replace On-Site" has also been eliminated from further evaluation due to the infeasibility of the option. This option is not feasible for several reasons including: 1) the short MATS compliance window compared to the length of time necessary for permitting, engineering, procurement, construction and startup testing of replacement generation at the site, and 2) the high cost of adding additional firm natural gas transportation for Plant Smith.

The option of "Retire & Replace Off-Site" remains under evaluation, but as a part of that evaluation the impact of the loss of the Plant Smith coal units on the transmission system needs to be considered. Gulf Witness Caldwell's rebuttal testimony discusses the projected Must-Run requirements for the Plant Smith coal units and the transmission upgrades required to address the reliability impacts of no longer having these units available to run, whether through retirement or otherwise. It should be noted that the transmission upgrades needed if the Plant Smith coal units are retired are the exact same transmission upgrades that have been previously mentioned in the context of the options of "Add Controls using Injection". The fact that the exact same transmission upgrades are needed for either of these two options can be seen in Mr. Norwood's Exhibit SN-6, page 3 of 8. Also, depending on the location of any replacement generation, in addition to the transmission upgrades discussed by Mr. Caldwell in his rebuttal testimony, additional transmission investment may be needed to support the replacement generation.

The option of "Add Controls using Scrubber" was compared to the option of "Add Controls using Injection". Gulf's evaluation has determined that the option of "Add Controls using Injection" will be a lower cost alternative for customers than the option of "Add Controls using Scrubber". Therefore, the option of "Add Controls using Scrubber" has been removed from further evaluation.

At this interim point in the process, there were three options remaining: 1) "Retire & Replace Off-Site" (which necessitates the proposed transmission upgrade), 2) "Add Controls using Injection with Transmission Upgrade", and 3) "Add Controls using Injection with Must-Run".

Q. Has Gulf performed further analysis leading to the elimination of any of these three options?

A. Yes, as discussed in Gulf's Environmental Compliance Program Update contained in Exhibit JOV-1, these three options were the options being evaluated by Gulf. Gulf has completed the evaluation of whether it is better to implement the option of "Add Controls using Injection with Transmission Upgrade" or the option of "Add Controls using Injection with Must-Run", but has not yet completed the evaluation of the option of "Retire & Replace Off-Site".

Q. Please explain the reason why the option of "Add Controls using Injection" initially had two alternatives: 1) "Add Controls using Injection with Transmission Upgrade", or 2) "Add Controls using Injection with Must-Run".

A. As described on page 22 of Gulf's Environmental Compliance Program Update contained in Exhibit JOV-1, and in Mr. Caldwell's rebuttal testimony, Plant Smith is projected to have Must-Run requirements under certain conditions in order to maintain the integrity of the electric system and provide reliable service to customers. If Plant Smith Units 1 and 2 are controlled using injection technology, starting in April 2015, there will be an increase in the cost of operation, including Must-Run operation, at Plant Smith driven by the use of sorbent injections as well as the use of a premium-priced coal for MATS compliance. These Must-Run requirements will persist into the foreseeable future unless transmission upgrades are implemented.

Q. Please describe the evaluation that was performed of the options of "Add Controls using Injection with Transmission Upgrade" and "Add Controls using Injection with Must-Run" (not upgrading the transmission).

A. The evaluation compares the projected total cost to customers of the two options in order to determine which of the two options has the lowest cost. More specifically, the evaluation compares the cost to customers for the transmission upgrade associated with the option of "Add Controls using Injection with Transmission Upgrade" to the fuel and other variable cost required to meet Plant Smith's Must-Run requirements under the option of "Add Controls using Injection with Must-Run" (not upgrading the transmission). It should be noted that the transmission upgrade capital costs associated with the evaluation of the option of "Add Controls using Injection with Transmission Upgrade" are the same as the upgrade costs for the "Retire & Replace" option and are found in Schedule 2, Exhibit PCC-2 of Mr. Caldwell's rebuttal testimony.

Q. What was the outcome of the evaluation?

A. The option of "Add Controls using Injection with Transmission Upgrade" was found to be more cost-effective for customers than the option of "Add Controls using Injection with Must-Run" (not upgrading the transmission). The results of this evaluation can be found in Table 3.3-2 on page 26 of Gulf's Environmental Compliance Program Update contained in Exhibit

JOV-1. Therefore, the "Add Controls using Injection with Must-Run" (not upgrading the transmission) option has been eliminated from further evaluation.

Q. What are the remaining viable options?

A. The two remaining options are: 1) "Retire & Replace Off-Site" (which necessitates transmission upgrades), and 2) "Add Controls using Injection with Transmission Upgrade" (which also necessitates the same transmission upgrades).

Q. Are there any common actions that would be needed for MATS and NERC compliance regardless of which of the two remaining options is determined to be the best option for customers?

A. Yes, as stated earlier, the same transmission upgrades associated with Plant Smith are needed for either of these two final options, as mentioned on pages 23 and 24 of Exhibit JOV-1. From a transmission perspective, there is no difference between these two options as they both mean that the existing coal-fired generation at Plant Smith is no longer available for Must-Run operation as discussed by Mr. Caldwell in his rebuttal testimony.

Q. Do you agree with Mr. Norwood's testimony on page 18, lines 13-15 that Gulf did not consider the alternative of early retirement of the Plant Smith coal units in its Environmental Compliance Program Update?

A. No. Gulf considered all of the potentially viable MATS compliance alternatives in determining its MATS compliance strategy. With regard to the early retirement of the Plant Smith coal units specifically, Mr. Vick's Exhibit JOV-1, Gulf's Environmental Compliance Program Update, includes references to retirement of the Plant Smith coal units as a compliance option on pages 22, 23, 24, 25, 26, and 27. Additionally, pages 22 and 27 both state that the analysis and the decision to install additional environmental controls on the Plant Smith coal units for MATS compliance or to retire and replace the units is ongoing and has not been completed. It should be noted that the retirement of Plant Smith would necessitate the transmission upgrades discussed by Mr. Caldwell, a fact apparently missed by Mr. Norwood.

Q. Do you agree with Mr. Norwood's statement regarding Plant Smith on page 22, lines 13-15 of his testimony that if approved, the Company's compliance plan would provide for Gulf to invest in transmission upgrades and invest in emissions controls for the Plant Smith coal units?

A. No, Mr. Norwood clearly does not understand Gulf's current MATS compliance strategy for Plant Smith. Gulf has not made a decision to invest in additional emission controls at Plant Smith. That evaluation is ongoing.

Q. What is Gulf's current MATS compliance strategy for the coal units at Plant Smith?

A. The compliance strategy is to: 1) implement the transmission upgrades associated with Plant Smith that are needed for either alternative, and 2) when more information is known about other anticipated EPA rules that will impact Plant Smith, update the analysis and economics of the two remaining compliance options ("Add Controls using Injection with Transmission Upgrade" and "Retire & Replace Off-Site" which requires the same transmission upgrades) in order to make a final decision between these two options. Although not the primary driver for implementing the transmission upgrades associated with Plant Smith, an added benefit of implementing the transmission upgrades now is that the upgrades give Gulf additional time to assess forthcoming EPA rules and analyze options while continuing to reliably and economically serve customers.

Q. Is Gulf requesting approval to invest in emissions controls on the Plant Smith coal units at this time?

A. No, contrary to Mr. Norwood's misrepresentation of Gulf's request, Gulf is not requesting approval to install additional controls on the Plant Smith coal units at this time. As mentioned previously, Gulf has not yet determined which of the two remaining MATS compliance options ("Add Controls using Injection with Transmission Upgrade" or "Retire & Replace Off-Site" which requires the same transmission upgrades) is in the best interest of customers and has not decided to implement additional controls at Plant Smith. If that decision is made at a later date, Gulf will present the rationale supporting such decision to the Florida Public Service Commission (Commission) for review at the appropriate time.

Q. Is Gulf requesting a determination from the Commission that moving forward with the transmission upgrade associated with Plant Smith as one part of its MATS compliance is in the best interest of customers at this time?

A. Yes, that is correct. As discussed by Mr. Caldwell, the transmission upgrade is required for either of the two remaining options ("Add Controls using Injection with Transmission Upgrade" and "Retire & Replace Off-Site" which requires the same transmission upgrades).

Q. Is it necessary to implement the transmission upgrades associated with Plant Smith at this time?

A. Yes, it is necessary. Under either of the two remaining MATS compliance options for Plant Smith, the transmission upgrades will need to be in place before compliance with MATS is required. Moreover, the MATS rule has a short compliance window so the transmission projects are already underway so they can be in service by the end of the compliance window in order to provide customers with economic and reliable service.

The transmission projects required for Plant Smith to achieve compliance with MATS are listed in Exhibit PCC-2, Schedule 2 of Mr. Caldwell's rebuttal testimony. Once permitting is secured, procurement and construction lead time for a set of transmission upgrades of this magnitude is several years, assuming construction of the project is on existing right of way.

II. Prudency of Gulf's Proposed Transmission Upgrades to Address MATS Compliance at Plants Crist and Smith

Q. Do you agree with Mr. Norwood's statement on page 13, lines 20-22 of his testimony that the proposed transmission upgrades for Plant Crist and Plant Smith are "not legally required to comply with any governmentally imposed environmental regulation?"

A. No, I disagree with his statement. The proposed transmission upgrades to address MATS compliance at Plant Crist and Plant Smith are legally required to comply with the MATS rule, to comply with NERC reliability requirements, and to provide economic and reliable electric service to Gulf's customers.

By Mr. Norwood's logic, one could assert that even if it were the lowest cost and most reliable option for customers, adding emission controls to a generation unit is not legally required to comply with MATS simply because other alternatives exist, such as conversion of the unit to gas or retirement of the unit. Such logic is flawed.

While I am not an attorney, my understanding is that prior to the MATS rule, Gulf had statutory obligations to provide economic and reliable electric service to customers and regulatory obligations to comply with NERC reliability requirements. When the EPA issued the MATS rule, it did not relieve Gulf of these previous obligations. Instead, the MATS rule placed an additional set of requirements on Gulf which necessitate that Gulf identify a compliance strategy that complies both with the new MATS requirements and with these previous statutory and regulatory requirements. Therefore, since the MATS rule is the new constraint, whatever actions are necessary to comply with the MATS rule while maintaining compliance with the pre-existing obligations must be deemed to be "legally required to comply with any governmentally imposed environmental regulation."

It is clear that the FDEP acknowledges that transmission investments may be needed for compliance with the MATS rule. Exhibit JAB-1, Schedule 2 is a letter from the FDEP precisely stating "from the Department's [FDEP] perspective, installing or upgrading transmission lines is a valid option to comply with and meet the regulatory requirements of MATS." Therefore, both by logic and by FDEP acknowledgement, the transmission upgrades are an integral part of Gulf's MATS compliance strategy for Plant Crist and Plant Smith.

Additionally, in the preamble to the EPA MATS rule, EPA discusses the fact that some companies might need to upgrade their transmission system to allow specific units to comply with the rule. So, in addition to FDEP acknowledging that transmission investment may be needed for compliance, from a transmission planning perspective, EPA recognizes that transmission may be needed for compliance.

Q. Mr. Norwood states an opinion on page 14 of his testimony that the scenarios for which the transmission upgrades are required are "extremely rare". Do the NERC planning requirements allow discretion in applying the requirements only to certain events?

A. No, NERC planning requirements necessitate planning for contingencies that comprise all combinations of a common point of failure on any one generating unit or plant and the loss of any one transmission line. When NERC reliability criteria are not met in Gulf's transmission planning models under any of these various contingency conditions, Gulf must either implement a transmission solution or have a plan for controlled interruption of firm electricity supply to remedy what would otherwise be non-compliance with the NERC reliability criteria.

Q. Do you agree with Mr. Norwood's statement on page 14, line 17 of his testimony regarding Gulf's support for its Must-Run operating criteria for Plant Crist and Plant Smith?

A. No, Gulf has a sound basis of support for its Must-Run operating and planning criteria, as discussed in the rebuttal testimony of Mr. Caldwell. The criteria are based on NERC reliability requirements and rigorous modeling of the Gulf generation and transmission system.

Q. Please explain the relationship between Must-Run and transmission planning.

A. Prior to EPA's adoption of the MATS rule, Gulf's transmission system was modeled based on forecasted operation, which assumed at least some generation from both Plant Crist and Plant Smith was supplied at all times. Since there are multiple generation units at each plant that could be independently operated, NERC reliability planning requirements could be met without reliance on controlled interruption of firm electricity supply to Gulf's customers. As stated previously, NERC reliability planning standards require that the electric system be able to withstand the loss of any one of the independently operated generating units on the Gulf system and an outage of any one transmission line without violation of any NERC planning criteria.

Q. Please explain how the MATS rule is the sole driver of dramatic changes in Must-Run and transmission planning associated with Plant Crist.

A. The emergence of the MATS rule significantly changed the reliability aspects of Must-Run with regard to Plant Crist. As mentioned in Mr. Vick's testimony on page 5 and re-iterated in Mr. Norwood's testimony on page 8, Plant Crist can, in fact, meet the stringent MATS requirements without additional controls except during periods when the scrubber is out of service. This exception, though, is highly important to compliance with NERC reliability requirements and Gulf's transmission reliability since all four units at Plant Crist share a common scrubber.

Prior to the MATS rule, it is permissible to bypass the scrubber while continuing to operate one or more of the Plant Crist units. Scrubber bypass enables one or more of the Plant Crist units to remain in operation either during periods of planned scrubber maintenance or scrubber malfunction. However, with the stringency of the MATS rule, Plant Crist, as it exists today, cannot comply with the rule when the scrubber is bypassed.

Therefore, the plant can no longer be operated without the scrubber in operation. Solely as a result of the new MATS rule, the four Plant Crist units can no longer be independently operated in the event of a scrubber malfunction or scrubber maintenance as they are today. This necessitates that Gulf take action to achieve MATS compliance.

For MATS compliance at Plant Crist, Gulf must choose between two options: 1) preserving the operational ability to bypass the scrubber, which would require additional environmental controls and/or fuel transportation costs, or 2) planning for those circumstances when the scrubber is off-line and no generation is available at Plant Crist, which necessitates transmission upgrades. As can be seen in Table 3.3-1 on page 17 of Exhibit JOV-1, the cost of preserving the ability to bypass the scrubber was determined to be much more expensive for customers than the transmission upgrades. Therefore, the transmission upgrades associated with Plant Crist are clearly caused solely by the emergence of the stringent MATS rule and are necessary to cost-effectively comply with the MATS rule while maintaining compliance with NERC requirements.

Q. Please explain how compliance with the MATS rule is the sole driver of significant changes in Must-Run costs for the Plant Smith coal units.

A. As previously discussed in my testimony, the screening and evaluation process that Gulf is performing on Plant Smith has determined that the two remaining Plant Smith compliance options are either: 1) "Add Controls using Injection", or 2) "Retire & Replace Off-Site". If the option of "Add Controls using Injection" is ultimately found to be the best compliance strategy for Plant Smith, the operating costs of the Plant Smith coal units will increase significantly due to the use of sorbent injections as well as the use of premium-priced coal. This significant increase in the operating cost of the Plant Smith coal units and therefore the transmission upgrades necessary to avoid costly Must-Run operation of the Plant Smith coal units are solely due to compliance with the MATS rule. Likewise, if the option of "Retire & Replace Off-Site" is ultimately found to be the best compliance option, the retirement of Plant Smith and, therefore, the need for the transmission upgrades associated with Plant Smith, would also be solely due to compliance with the MATS rule.

Q. Do you agree with Mr. Norwood's statements on pages 15, 16, and 17 of his testimony regarding Gulf's support for the benefits of eliminating Must-Run constraints at Plant Crist and Plant Smith and the reasonableness of Gulf's Must-Run analysis?

A. No, Gulf has completed a reasonable analysis that clearly demonstrates the benefits of eliminating the Must-Run requirements for Plant Crist and Plant Smith. The transmission upgrades associated with both plants are the most cost-effective means of compliance with MATS while adhering to NERC reliability standards.

Q. Looking first at Plant Crist, please explain how Gulf determined that transmission upgrades were the most cost-effective means of complying with MATS while maintaining compliance with NERC reliability standards.

A. Gulf considered two primary options for MATS compliance at Plant Crist. The first preserves the ability to bypass the scrubber (which entails future Must-Run operation of Plant Crist units at higher costs than is incurred by Must-Run operation of the plant today, as well as additional environmental control costs and/or fuel transportation costs). The second eliminates the need to bypass the scrubber by eliminating Must-Run operation (which necessitates transmission upgrades).

The three specific options considered to preserve the ability to bypass the scrubber were: 1) increasing the capability of natural gas generation at the plant and requiring Must-Run operation as necessary to meet NERC Reliability Standards, 2) adding injections of activated carbon and sorbent at the plant and requiring Must-Run operation as necessary to meet NERC Reliability Standards, and 3) adding only enough transmission upgrades to reduce, but not eliminate, Must-Run operation at the site to meet NERC Reliability Standards. As an alternative to preserving the ability to bypass the scrubber, one specific option was considered. That option is to rely solely on transmission upgrades with no injections and with no Must-Run requirement for any of the units. In its evaluation, the Company assessed the total cost to customers of each option.

As mentioned by Mr. Norwood in his testimony, the Company used some simplifying Must-Run assumptions in its analysis. The assumptions were both appropriate and reasonable regarding the quantity and timing of future Plant Crist Must-Run operations. In assessing the cost of Must-Run, the

Company first developed its assumption about the amount of Must-Run operation by iteratively lowering the assumed Gulf Power load in its transmission planning models until steady state and dynamic reliability criteria were met. Once this "no Must-Run" load level was determined, the analysis did not try to determine hour by hour in each of the more than 80,000 individual hours of the analysis period whether the Plant Crist coal units would need to be operating. Instead, the next step of the analysis was an assessment of load levels across the year. The assessment involved analyzing loads by month and then by hour to determine which months and which hours of the month had loads routinely exceeding the previously determined "no Must-Run" load level. So, the "simplifying assumption" employed was to substitute a few hours in a few months where loads routinely exceeded the no Must-Run load level rather than identifying every such hour during the year. This was a simplifying and quite conservative adjustment.

In the next step of the analysis the modeled Must-Run operation of the Plant Crist units was then set for the months and hours determined by the previous step, while reflecting operational constraints of the units such as startup time. The projected cost of this Must-Run operation was calculated as the difference between Plant Crist's total operating cost with Must-Run operation and the plant's total operating cost if no Must-Run requirements existed, as would be the case with the transmission upgrades. The comparison of the transmission cost versus the Must-Run cost shows that the transmission upgrades are clearly more cost-effective than Must-Run operation.

Therefore, the economics appropriately and reasonably state the projected cost of Must-Run operation. As can be seen in Table 3.3-1 on page 17 of Exhibit JOV-1, the cost of preserving the ability to bypass the scrubber and maintain Must-Run operation was determined to be more costly for customers than the alternative of transmission upgrades that eliminate the need to bypass the scrubber as well as the need for Must-Run operation. Additionally, the results of the economic analysis strongly demonstrate the benefits to customers of the Plant Crist transmission upgrades which are caused solely by cost-effective compliance with the MATS rule while maintaining continued compliance with NERC Reliability Standards.

Q. Turning next to Plant Smith, please explain how Gulf determined that transmission upgrades were integral to a cost-effective means of complying with MATS and NERC reliability standards.

A. As previously discussed in my testimony, Gulf's evaluation narrowed the range of options for MATS compliance down to three options: 1) "Retire & Replace Off-Site" (which requires transmission upgrades), 2) "Add Controls using Injection with Transmission Upgrade", and 3) "Add Controls using Injection with Must-Run". Economic evaluation comparing the two options associated with "Add Controls" has been completed. The only difference between these two options is whether the Plant Smith coal units' Must-Run obligations are eliminated or whether they continue Must-Run operation despite their higher operating cost resulting from the addition of emission controls using sorbent injection to comply with MATS. The economic evaluation compares the cost of the transmission upgrades to the cost of continued Must-Run with the use of sorbent injection and premium-priced coal.

Gulf used a reasonable assumption regarding the quantity and timing of future Plant Smith coal unit Must-Run operations. Specifically, Gulf modeled the Must-Run operation of the Plant Smith coal units similar to Mr. Norwood's Exhibit SN-3, which shows that under certain conditions at least one Plant Smith coal unit must be in operation and at certain higher load level conditions both coal units must be in operation. Gulf's simplifying assumption which Mr. Norwood references was the fact that the analysis did not try to determine hour by hour in each of the more than 65,000 individual hours of the analysis period whether one or both of the Plant Smith coal units would be operating. Instead, the analysis began with an assessment of load levels across the year. The assessment involved analyzing loads by month and then by hour to determine which months and which hours of the month had loads comparable to the various Plant Smith Must-Run conditions in Mr. Norwood's Exhibit SN-3. In the next step of the analysis the modeled Must-Run operation of the Plant Smith coal units was then set for the months and hours determined by the previous step, while reflecting operational constraints of the coal units such as startup time. The projected cost of this Must-Run operation was calculated as the difference between Plant Smith's total operating cost with Must-Run operation and the plant's total operating cost if no Must-Run requirements existed, as would be the case with the transmission upgrades.

The comparison of the transmission cost versus the Must-Run cost shows that the transmission upgrades are clearly more cost-effective than Must-Run operation. The results of the economic analysis can be found on page 26 of Exhibit JOV-1. These economic analysis results strongly demonstrate the benefits to customers of the Plant Smith transmission upgrades which are caused solely by compliance with the MATS rule and the need for continued compliance with NERC standards.

Q. Do you agree with Mr. Norwood's statement on page 22, lines 15-19 of his testimony regarding the potential for stranded cost or getting the cart before the horse in regard to the transmission upgrades associated with Plant Smith?

A. No, Mr. Norwood is unmistakably wrong to assume there is potential for stranded cost or that Gulf is getting the cart before the horse. The fact is that the transmission upgrades for Plant Crist <u>and</u> Plant Smith are necessary for economic compliance with the MATS rule while maintaining reliability of electric service to Gulf's customers. I have shown that the transmission upgrades associated with Plant Crist are the most cost effective and reliable means of MATS compliance for Plant Crist, and have shown that the only two remaining cost effective and reliable means of compliance for Plant Smith both include the transmission upgrades associated with Plant Smith. Therefore, there is no potential for stranded cost due to possible retirement of Plant Smith, as Mr. Norwood incorrectly stated.

Q. Do you agree with Mr. Norwood's statement on page 23, lines 1-2 of his testimony regarding the necessity of the transmission upgrades associated with Plant Crist and Plant Smith and the prudency of the upgrades?

A. No, Mr. Norwood is wrong to assume that transmission upgrades are not needed for MATS compliance while maintaining compliance with NERC Reliability Standards. Therefore, he is also wrong to assume these transmission costs are not prudent.

While it is true that the EPA MATS rule allows some compliance flexibility and therefore no specific, single compliance option is mandated or legally required, <u>one</u> of the options must be implemented to comply with the MATS rule while maintaining compliance with NERC Reliability Standards. Moreover, Gulf is obligated to implement the most economic and reliable option and implementing the transmission upgrades has been shown to be the most economic and reliable course of action for Plant Crist and for Plant Smith.

As I have shown in my testimony, the transmission upgrades associated with Plant Crist and Plant Smith are required for economic compliance with the MATS rule while maintaining compliance with NERC Reliability Standards and are therefore both necessary and prudent. Additionally, the transmission upgrades associated with Plant Smith have been shown in my testimony to be necessary for either of the two remaining economic and reliable MATS compliance options and are therefore prudent.

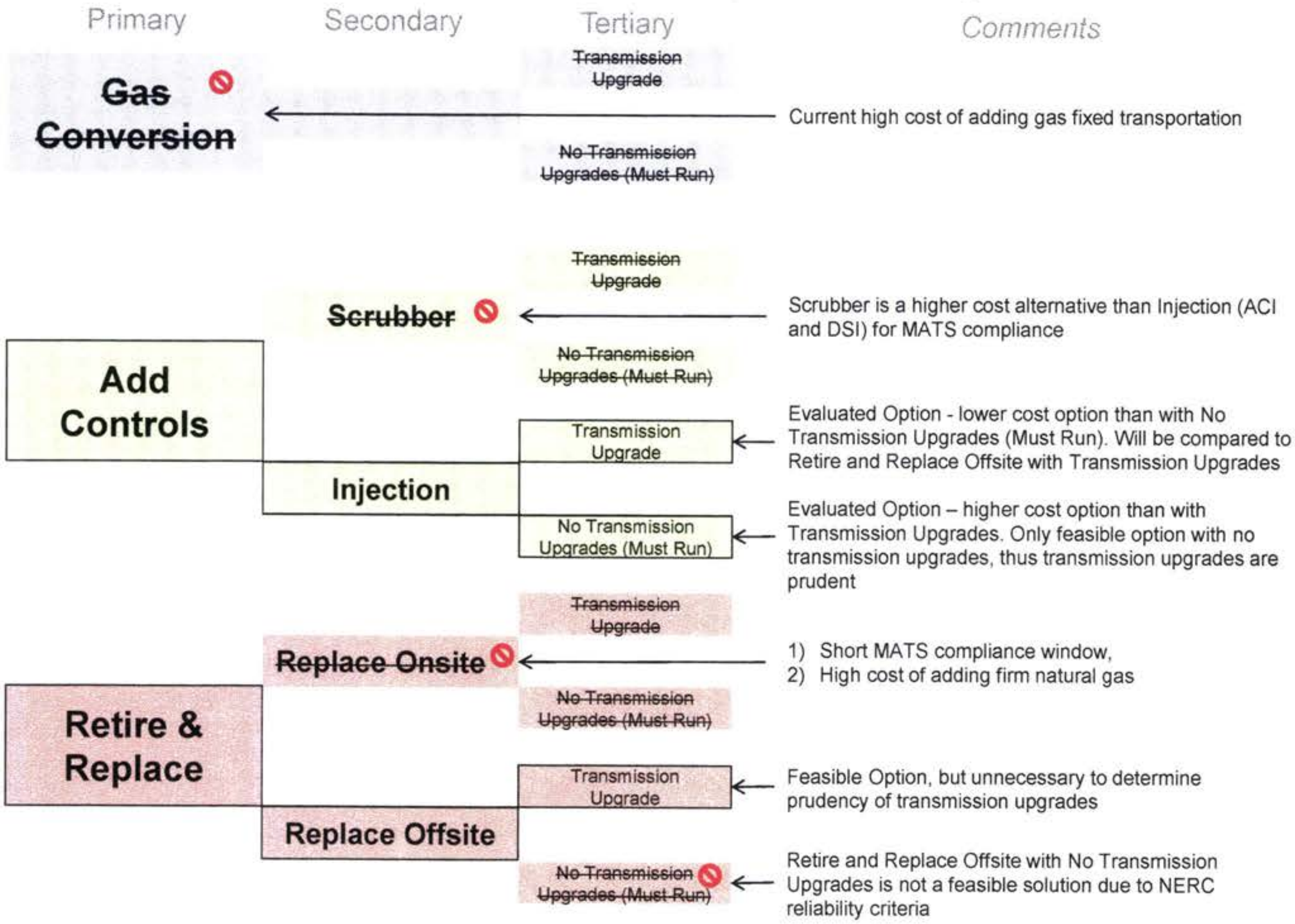
Q. Does this conclude your testimony?

A. Yes.

Exhibit

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Jeffrey A. Burleson
Exhibit No. (JAB-1)
Schedule 1
Page 1 of 1

Plant Smith Units 1 and 2 Evaluation Flow Diagram



FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

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RICK SCOTT
GOVERNOR

HERSCHEL T. VINYARD JR.
SECRETARY

Sent by Electronic Mail

June 28, 2013

Mr. Braulio Baez
Executive Director
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Gulf Power Company
Compliance Strategy, Mercury and Air Toxics Rule
Docket No. 130007-EI

Dear Mr. Baez,

The Florida Department of Environmental Protection's Division of Air Resource Management recently met with representatives of Gulf Power Company to discuss Gulf's compliance strategy in relation to the U.S. Environmental Protection Agency's recent Mercury and Air Toxics Rule ("MATS"). Gulf described its evaluation to determine the most reasonable and prudent options to comply with this rule, while ensuring that it continues to meet its reliability obligations. I understand that the Public Service Commission currently is reviewing Gulf's updated environmental compliance plan, which includes the Plant Crist and Plant Smith Transmission Upgrades Projects for MATS compliance. I am sending this letter to confirm that, from the Department's perspective, installing or upgrading transmission lines is a valid option to comply with and meet the regulatory requirements of MATS.

In the preamble to the final MATS rule, EPA discussed the possibility that some companies might need to install or upgrade transmission to allow specific units to comply with the rule. 77 Fed. Reg. 9,409-11 (Feb. 16, 2012). EPA discussed this transmission-compliance option in the context of maintaining system/grid reliability while specific units installed controls or retired, in order to comply with the April 16, 2015 compliance deadline. EPA specifically concluded that transmission upgrades fall within the scope of "installation of controls" for purposes of seeking an extension to this deadline where there are reliability concerns. The Department appropriately will defer to the Commission regarding reliability assessments associated with Gulf's plans, but, as the permit authority, is comfortable with Gulf's plans at this state to achieve compliance with MATS.

The Department would view an order from the Commission approving Gulf's updated environmental compliance program to be sufficient indication that Gulf's MATS-related plan for transmission system upgrades in regards to Plant Crist and Plant Smith are necessary and appropriate in terms of the continuing functionality of the electric grid. The current timetable for a Commission decision, which I understand is scheduled for July 30, 2013, would meet our needs.

If you have any questions regarding this information, please contact me at (850) 717-9000.

Sincerely,

Brian Accardo

Brian Accardo, Director
Division of Air Resource Management
Department of Environmental Protection

BA/vg

cc: Ann Cole, PSC Clerk
James O. Vick, Gulf Power Company
Jeff Littlejohn, FDEP

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

MICHAEL L. BURROUGHS

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Michael L. Burroughs
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Michael L. Burroughs. My business address is One Energy Place, Pensacola, Florida 32520. I am Vice President of Gulf Power Company (Gulf or the Company) with responsibility for Power Generation, and in that capacity I am Senior Production Officer.

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. Do you have an exhibit associated with your rebuttal testimony?

A. Yes. I sponsor Exhibit MLB-2, consisting of one schedule. It was prepared under my direction and supervision, and the information contained therein is true and correct to the best of my knowledge and belief.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond to one of the adjustments contained in the testimony of Office of Public Counsel (OPC) Witness Jacob Pous. Mr. Pous argues that the interim retirement rate in Other Production Account 343 should be lower than the amount proposed by Gulf Witness Huck on behalf of the Company. In attempting to support this adjustment, Mr. Pous makes statements or assertions about Gulf's experience with its power generation fleet that are inaccurate. My rebuttal addresses why Mr. Pous' statements are inaccurate and should not be relied upon.

Q. Are you an expert on utility depreciation?

A. No. My expertise is in the field of utility power generation. It is that expertise I rely upon in rebutting Mr. Pous' inaccurate statements.

Q Please address Mr. Pous' adjustment to the interim retirement rate for Account 343 - Other Production Prime Movers Combined Cycle Generation.

A. Mr. Pous argues in his testimony that an interim retirement rate of 1 percent or $1.2 million of future expected annual interim retirements should be used for Account 343. This compares to an interim retirement rate of 2 percent or $2.3 million in future expected annual interim retirements proposed and supported by Mr. Huck's analysis. Mr. Pous testifies that his proposed reduction of the interim retirement rate for Account 343 would lower Gulf's annual depreciation expense by $1,111,513.

In arguing for a lower interim retirement rate for Account 343, Mr. Pous makes the following claims that I rebut:

(1) That Gulf has limited experience with its combined cycle units.

(2) That the differences between the combined cycle units and the equipment located at our coal-fired generating facilities mean that the combined cycle units should not exhibit similar levels of interim retirement expected at coal-fired units.

(3) That allowing only $1.2 million for future expected annual retirements at Smith Unit 3 combined cycle facility is sufficient given the experience thus far with that facility.

Q. Please respond to Mr. Pous' claim that Gulf has only limited experience with combined cycle facilities.

A. Mr. Pous' statement is inaccurate both as to Gulf and Southern Company. We have a great deal of experience with combined cycle units at Gulf and throughout Southern Company.

Gulf's Lansing Smith combined cycle unit three achieved commercial operation in 2002. Gulf has eleven years of experience with its "new" combined cycle unit. Additionally, Gulf also has access to and utilizes the technical expertise and work practices of the other Southern operating companies, which are Alabama Power, Georgia Power, Mississippi Power, and Southern Power. Southern Company has a long history of constructing, owning, maintaining and operating more than 21 combined cycle units with 40 combustion turbines. Our first units have been in service since as early as 1999. Our fleet of combined cycle units is a mature fleet with major outages routinely completed on multiple units. Mr. Pous' statement that we have limited experience with combined cycle units is completely inaccurate. In fact, Southern Company, of which Gulf is a part, has extensive experience with combined cycle construction, operation and maintenance.

Q. What is your personal experience with combined cycle units?

A. Over the course of my career, I have nearly two decades of experience working in various maintenance and operational roles across the Southern electric system from "boots on the ground" experience to leadership positions at power plants with combined cycle units. Specifically, one of my roles was to serve as Group Leader of Maintenance for the Smith combined cycle unit. I personally have had responsibility for directing and leading all maintenance activities for the Mechanical, Electrical, and Instruments and Controls groups for this unit as well as executive oversight for the most recent outage completed on this unit. Gulf has owned and operated this unit for over a decade.

Q How do you respond to Mr. Pous' claim that because new combined cycle units are not similar to the equipment located at a coal-fired generating facility, they should not exhibit the same level of retirement expected at coal-fired units?

A. I disagree. Ultimately, the issue is not how retirements at coal units and combined cycle units compare; the issue is what a reasonable projected level of annual expected retirements is for a combined cycle unit. I will discuss Gulf's actual annual retirement experience and projected annual retirements later in my testimony. Although coal-fired units and natural gas-fired combined cycle units employ two different technologies, there are a number of similar types of equipment employed in both technologies. Regardless of the similarities and differences, the issue is what is a reasonable level of interim retirements to assume for the future.

Like coal-fired units, combined cycle units also have equipment that requires maintenance and replacement. Below is an example of some of the costly equipment in the prime mover account that was replaced in the Plant Smith combined cycle combustion turbine during a major outage which was completed in early 2013. The equipment listed below requires routine replacement approximately every 24,000 fired operating hours, which presently works out to be every three years. This is a more frequent schedule than coal-fired units require for their turbines.

- Fuel Nozzles
- Hot Gas Transition Pieces
- Turbine Nozzles
- Combustion Liners
- Shroud
- Turbine Blades

Additional high cost combined cycle turbine equipment is shown below. This equipment has non-routine replacement requirements and is also accounted for in the prime mover account, Account 343.

- Bearing seals
- Compressor blades

Also within the prime mover account for the combined cycle unit but not related to the combustion turbine, the following costly equipment which is similar to equipment in coal fired units requires non-routine inspection, maintenance and replacement of various components within each of the following major equipment categories every 48,000 fired operating hours.

- Steam turbine/generator (STG)
- Heat recovery steam generator (HRSG)
- Boiler feed pumps and motors
- Condensate pumps and motors
- Mechanical draft cooling tower

The equipment list above is not an all-inclusive list but is an example of some of the more costly components within the prime mover account for a combined cycle. Mr. Pous' contrast of coal-fired units with combined cycle units is misleading.

Q How do you respond to Mr. Pous' claim that $1.2 million for future annual interim retirement at the Plant Smith combined cycle will provide the Company with more than adequate protection?

A. I disagree. Mr. Pous' claim is based on his improper characterization of the Plant Smith combined cycle facility as a "new combined cycle generation station." Smith Unit 3 has been in service for over a decade. Both our actual experience at Smith Unit 3 and our combined system experience with the combined cycle fleet in the Southern electric system provides us with sufficient representative empirical data to support the analysis of Mr. Huck who developed the proposed level of interim retirements presented on behalf of Gulf in this proceeding. From my knowledge and experience, the $1.2 million that would result from Mr. Pous' recommendation is simply inadequate.

Q. Based upon its actual experience with Smith Unit 3, has Gulf developed an estimate of prospective retirements at the Plant Smith combined cycle unit?

A. Yes. Gulf has now performed two major outages under the terms of our long term service agreement with General Electric on this unit since 2008. The first was completed in 2010 and another was completed in early 2013. The average annual actual retirements experienced over the last six years were $6,675,000 per year as reflected on Schedule 1 of Exhibit MLB-2. Gulf will continue to have similar major outages at the Plant Smith combined cycle unit under our long term service agreement, and if this unit continues to dispatch as it has over the last six years, such major outages (and significant associated retirements) will occur approximately every three years.

The average annual retirements for the next three years is expected to be $7,031,000 per year with another major outage projected for 2016. These projections are also shown on Schedule 1 of my Exhibit MLB-2. Gulf expects this level of annual retirements to continue over the remaining life of this unit. Clearly, Mr. Huck's proposed level of expected annual interim retirements of $2.3 million is conservative, and Mr. Pous' proposed level of $1.2 million of annual interim retirements at the Plant Smith combined cycle is not "adequate protection." It is grossly inadequate.

Mr. Pous states in his own testimony: "While review of historical data provides an indication of what has occurred, it must be tested for reasonableness as it applies to future expectations." When applying

Mr. Pous' concept to Account 343, it is clear that Mr. Pous' $1.2 million level of annual interim retirements is unreasonable in that it is far too low.

Q. Please summarize your rebuttal testimony.

A. In his adjustment to interim retirements in Account 343, Mr. Pous makes several inaccurate factual statements. These inaccuracies clearly distorted his judgment and led him to propose a prospective $1.2 million level of Gulf combined cycle retirements that is too low by any reasonably informed approach. Mr. Pous' adjustment should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Michael L. Burroughs
Exhibit No. ___(MLB-2)
Schedule 1
Page 1 of 1

Account 343 - Prime Movers Combined Cycle
(In 000's)

Year	Actual Additions	Actual Retirements	End of Year Balance
2008	$ -	$ 572	$ 94,123
2009	-	62	94,061
2010	38,812	18,742	114,131
2011	336	769	113,698
2012	483	249	113,932
Sept 2013 YTD	21,795	19,657	116,070
Average	$ 10,238	$ 6,675	$ 107,669

Year	Projected Additions	Projected Retirements	End of Year Balance
2014	$ 1,700	$ 950	$ 116,820
2015	1,750	950	117,620
2016	31,900	19,193	130,327
Average	$ 11,783	$ 7,031	$ 121,589

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

P. CHRIS CALDWELL

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
P. Chris Caldwell
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Chris Caldwell. My business address is One Energy Place, Pensacola Florida, 32520 and I am the Transmission General Manager for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will address portions of the direct filed testimony of Office of Public Counsel (OPC) Witness Norwood. First, I will address Mr. Norwood's testimony regarding Gulf's designation of Plant Crist and Plant Smith units as Must-Run. I explain Gulf's minimum transmission system requirements for generation and describe Gulf's support for the designation of Must-Run for specific units. I will also demonstrate that the current transmission system as constructed today cannot reliably support our customers or comply with NERC Reliability Standards at all times without some level of generation online at Plant Smith and Plant Crist, specifically in 2015 when the Mercury and Air Toxics Standards (MATS) rules become effective. In addition, I will address Mr. Norwood's testimony regarding the prudency of the MATS related transmission projects identified and developed as part of Gulf's Ten Year Transmission Plan. Lastly, I will address Mr. Norwood's position regarding the prudency of the transmission upgrades associated with Plant Smith and the Company's ongoing analysis of unit retirements at Plant Smith related to MATS.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes, I am sponsoring Exhibit PCC-2, Schedules 1 and 2. Exhibit PCC-2 was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge and belief.

I. MUST-RUN DESIGNATION

Q. Please describe what Gulf means by the term Must-Run.

A. Must-Run refers to the designation of specific generating units that are required to be online and producing power to support the reliability of the transmission system during certain system conditions.

Since electrical power is perhaps the only product that must be consumed the instant that it is created, its transportation system is a critical, yet complex model. Matching the production or generation of electrical power with consumption in real time on a continuous basis is an extremely complex task. As Gulf's operators and planners strike this balance, forecasts have to be made about what generation resources will be online and supplying power. For certain system conditions and due to the inherent nature of the transmission network, there are generation resources across the system that are identified as required to support reliability. For some of the units it is reasonable to assume they will be online because of their relative position in the Company's dispatch order. For other units, if there is uncertainty regarding when the unit will be online, the required units may be designated as Must-Run to address reliability constraints during certain system conditions. This designation of Must-Run is designed to communicate to all parties (plant operations, fleet operations, planners and other interested parties) that, regardless of economics or other operational efficiencies, these designated Must-Run units are required for transmission support. This guidance for Must-Run is designed to ensure the Company can reliably serve its customers and is able to comply with NERC Reliability Standards requirements.

Q. Have units at Gulf Power's Plant Smith and Plant Crist been designated as Must-Run?

A. Yes. Since Plant Crist and Plant Smith began commercial operations in 1945 and 1965 respectively, Gulf Power transmission planning studies have always modeled the bulk electric system (system) with some level of generation online at these two plants. Thus, since their original commercial operation, some level of generation from these two plants has been committed and dispatched from a transmission planning perspective and also required in the real time operation of the system. The transmission system has been designed around the expected dispatch of these resources. Therefore, in matching production to consumption in real time, the transmission system has become reliant on local generation and specific plants. It is this reliance on generation built into the design of the system that requires Gulf to designate certain units under certain system conditions to be Must-Run.

Q. Do you agree with Mr. Norwood's statement that the Must-Run requirements are unsupported?

A. No. The Company has studied these minimum system requirements for generation and the identification of Must-Run units extensively over time. What is important in this discussion is what the minimum requirements will be for Gulf Power's transmission system in 2015 when the new MATS rules take effect. Regardless of how the term Must-Run is used or defined and regardless of the historical operation of the Gulf units, there are clearly minimum transmission system requirements that will require units at Plant Smith and Plant Crist to be online in 2015 _if_ we do not make investments in the existing transmission system.

Q. Does the Company have an analysis of the impact to reliability and Gulf's customers in 2015 that substantiates the Must-Run designation at Plant Crist and Plant Smith?

A. Yes. Gulf develops a Ten Year Transmission Plan (or Transmission Plan) for the transmission system and updates that plan annually. For the annual update of the plan in 2012, the Company removed all Must-Run requirements for Plant Smith and Plant Crist. Specifically, this meant the

Company assumed that in April 2015 it would not be able to dispatch Plants Crist and Smith generation to meet the minimum system requirements or Must-Run requirements like it does today. The Ten Year Transmission Plan submitted as Schedule 1 of Exhibit PCC-2 substantiates that the current transmission system requires generation from Plant Crist and Plant Smith to be online under certain conditions or there are significant reliability issues. The Transmission Plan also documents the projects and investment needed if the Company is not able to rely on generation to run at Plant Crist and Plant Smith. This plan is clear evidence that the Company only has two choices from a transmission perspective; Gulf must either continue to run units at Plant Crist and Plant Smith to meet the Must-Run requirements or implement the documented transmission improvements. Mr. Norwood includes a portion of Gulf's Ten Year Transmission Plan as an exhibit to his testimony showing that he should be familiar with the findings in that document. His erroneous conclusions with regard to what is included in the Transmission Plan at a minimum call into question his expertise in the area of transmission planning.

Q. Do you agree with Mr. Norwood's suggestion that the purpose of the transmission upgrades related to Plant Crist and Plant Smith is to address potential transmission overloads and voltage regulation concerns?

A. Yes. These overloads and voltage regulation concerns are driven by the MATS compliance requirements which change the Company's ability to dispatch existing generation to support the transmission system as we do today. Gulf Witness Vick addresses the MATS compliance requirements and their impact on Plant Crist in his direct testimony. As well, Gulf Witness Burleson further documents the Company's MATS compliance impacts and the required changes in unit operations.

Q. Why does the Company's Transmission Plan include cases that consider the loss of all generation at a Plant and an outage of a transmission element on the system?

A. These cases or scenarios are consistent with Southern Company's Guidelines for Planning the Southern Company Electric Transmission System. These guidelines are submitted to FERC as part of a regulatory filing and ensure compliance with NERC Transmission Planning (TPL) Reliability Standards requirements. The guidelines specifically require the study of a generator offline and an outage on another transmission element (transmission line or transformer). The study must demonstrate the electrical system can remain within facility operating limits following these events and if the system cannot, a plan must be implemented which maintains the electrical system reliability.

As Mr. Burleson discusses, beginning in April 2015 MATS requirements will preclude the current practice of bypassing the scrubber at Plant Crist in the event of a scrubber outage. Therefore, a scrubber outage will remove <u>all</u> generation at Plant Crist. Because of this change in the ability to bypass the scrubber, the Company must treat the loss of all generation at Plant Crist as a single contingency for planning purposes, since the outage of the common scrubber will affect all generation at the plant.

Mr. Burleson also discusses the potential impacts of the MATS rules on Plant Smith Units 1 and 2, which required Gulf to conduct the planning studies and model the system with these units offline (either retired or otherwise not available to meet Must-Run requirements) beginning in April 2015. As required, the Company studies the impacts to the transmission system for the loss of these units.

II. TRANSMISSION TEN YEAR PLAN – PLANT CRIST

Q. What would the impact be on Gulf's customers if there was no generation online at Plant Crist?

A. The results of the planning study, described on pages 10 and 13 of the Transmission Plan, show that under certain conditions the contingency of a scrubber outage (meaning that Units 4-7 at Plant Crist are off line) would result in the inability to serve customer load and could require operator actions resulting in widespread customer outages in the Pensacola area. The Company does not plan to interrupt customer electrical supply in these events and will comply with both the EPA and NERC requirements by planning for and completing the needed transmission investment to mitigate these types of reliability issues.

The Transmission Plan demonstrates and supports the Company's conclusion that the current transmission system must have some level of generation online at Plant Crist to avoid significant reliability risk to our customers and thereby supports the Company's Must-Run guidance.

Once the transmission investment is completed for the proposed area projects, the Company does not forecast a need for Must-Run requirements at Plant Crist and will be able to reliably support the transmission system in the circumstances when generation is not available at Plant Crist.

Q. What are the specific projects that are required to maintain reliability and compliance with NERC Reliability Standards in the event that generation is not available at Plant Crist after the MATS rules go into effect in April 2015?

A. The projects that would be required are listed in Exhibit PCC-2, Schedule 2.

Q. Has the Company already begun to implement the projects needed for transmission reliability related to MATS as documented in the Transmission Plan and in Exhibit PCC-2, Schedule 2?

A. Yes. The projects that are required to be in service by 2015 are all underway. As Witness Burleson explains, these transmission upgrades have been determined to be the most cost effective solution to comply with the MATS rules. Projects of this magnitude require long lead times for design, manufacture and construction. These projects include the construction of a new 230 kV transmission line, extensive substation terminal construction and specifically designed voltage control technology. To meet the required in service dates to maintain reliability, each of the projects are in various stages of design, procurement and construction.

III. TRANSMISSION TEN YEAR PLAN – PLANT SMITH

Q. Please discuss the analysis in Gulf's Transmission Plan for Plant Smith.

A. Gulf included in its Transmission Plan an assumption that Smith Units 1 and 2 would not be available to meet Must-Run requirements starting in April 2015. The Transmission Plan shows that, without Plant Smith Units 1 and 2 available, transmission upgrades are needed for Gulf to maintain the necessary transmission stability to meet customer load and comply with NERC Reliability Standards. In fact, the same transmission upgrades are needed regardless if Smith Units 1 and 2 are retired or if the Company choses to control the units and remove the Must-Run requirements.

Q. What would the impact be on Gulf's customers if there was no generation online at Plant Smith?

A. The Transmission Plan shows several conditions that result in the inability to maintain a reliable transmission system if Smith Units 1 and 2 are not online and if the Company experiences a loss of Smith Unit 3. Specifically, the analysis on page 69 of the Transmission Plan shows that under certain conditions, if Smith Unit 3 trips, the transmission system cannot maintain voltage control. Additionally, with the loss of Smith Unit 3, Gulf is one contingency away from reliability issues that would cause widespread outages for customers.

The Transmission Plan demonstrates and supports the Company's conclusion that with the transmission system as it exists today, without some level of generation online for Smith Units 1 and 2 there is significant reliability risk to our customers and thereby supports the Company's Must-Run guidance.

Q. Mr. Norwood suggests that the transmission investments associated with MATS compliance at Plant Smith would not be necessary in the event the Company decided to retire Smith Units 1 & 2. Do you agree with this suggestion?

A. No, Mr. Norwood has it wrong despite his having Gulf's Ten Year Transmission Plan, the direct testimony of Mr. Vick (page 11) and Gulf's 2013 Environmental Compliance Program Update (Page 26), each discussing that without generation from Plant Smith Units 1 and 2, transmission upgrades are needed for Gulf to maintain the necessary transmission stability to meet customer load and comply with NERC Reliability Standards at all times.

The current Transmission Plan for Plant Smith assumes Units 1 and 2 are not available to run for transmission support beginning in April 2015. This assumption requires the Company to implement the needed transmission projects to continue to maintain system reliability.

Q. What are the specific projects that are required to maintain reliability and compliance with NERC Reliability Standards related to MATS for Plant Smith?

A. The projects that would be required are listed in Exhibit PCC-2, Schedule 2.

Q. Has the Company already begun to implement the projects needed for transmission reliability related to MATS as documented in the Transmission Plan and in Exhibit PCC-2, Schedule 2?

A. Yes. The projects that are required to be in service by 2015 are all underway. As Witness Burleson explains, these transmission upgrades are essential to both of the only remaining alternatives under consideration for the Plant Smith MATS compliance strategy. Projects of this magnitude require long lead times for design, manufacture and construction. These projects include the construction of a new 230 kV transmission line, extensive substation terminal construction and specifically designed voltage control technology. To meet the required in service dates to maintain reliability, each of the projects are in various stages of design, procurement and construction.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: P. Chris Caldwell
Exhibit No. ___(PCC-2)
Schedule 1

Gulf Power Company
Ten Year Transmission Plans
2012 Assessments for Planning Horizon 2013-2022

Confidential in its entirety

MATS - Planning Projects			Total In Service Budget				
PE	Description	In Service	2014	2015	2016	2017	2018
	Plant Crist MATS Projects						
280301	Pensacola Svc (Alligator Swamp)	2015		16,509			
281301	North Brewton - Alligator Swamp 230 Line	2015		34,002			
281302	Alligator Swamp Substation	2015		252			
284801	Alligator Swamp 90Mvar 230 kV Cap Bank	2015		2,100			
285101	West Pensacola Ring Bus and Cap Bank	2016			2,300		
282601	Brentwood - Scenic Hills #2 115 Reconductor	2017				4,500	
280302	Pensacola Svc (W. Pensacola)	2018					16,671
	Plant Smith MATS Projects						
282901	Panama City Svc (Highland City)	2015		16,000			
286701	Holmes Creek - Highland City New 230 kV - Line	2015		39,790			
286703	Holmes Creek - Highland City New 230 kV - Autobank	2014	16,652				
286707	Holmes Creek - Highland City New 230 kV - Cap Bank	2014	2,122				
286709	Rebuild Holmes Creek - Bonifay Tap Section Double Circuit	2014	1,518				
	Totals		20,292	108,653	2,300	4,500	16,671

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY

OF

J. TERRY DEASON

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
J. Terry Deason
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Terry Deason. My business address is 301 S. Bronough Street, Suite 200, Tallahassee, FL 32301. I am a Special Consultant for the Radey Law Firm specializing in the fields of energy, telecommunications, water and wastewater, and public utilities.

Q. Please describe your educational background and professional experience.

A. I have thirty-six years of experience in the field of public utility regulation spanning a wide range of responsibilities and roles. I served a total of seven years as a consumer advocate in the Florida Office of Public Counsel (OPC) on two separate occasions. In that role, I testified as an expert witness in numerous rate proceedings before the Florida Public Service Commission (Commission). My tenure of service at OPC was interrupted by six years as Chief Advisor to Florida Public Service Commissioner Gerald L. Gunter. I left OPC as its Chief Regulatory Analyst when I was first appointed to the Commission in 1991. I served as Commissioner on the Commission for sixteen years, serving as its chairman on two separate occasions. Since retiring from the Commission at the end of 2006, I have been providing consulting services and expert testimony on behalf of various clients. These clients have included public service commission advocacy staff and regulated utility companies, before commissions in Arkansas, Florida, Montana, New York and North Dakota. My testimony has addressed various regulatory policy matters, including: regulated income tax policy; storm cost recovery procedures; austerity adjustments; depreciation policy; subsequent year rate adjustments; appropriate capital structure ratios; and prudence determinations for proposed new generating plants and associated transmission facilities. I have also testified before various legislative committees on regulatory policy matters. I hold a Bachelor of Science Degree in Accounting, summa cum laude, and a Master of Accounting, both from Florida State University.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain assertions and recommendations made by intervenor witnesses Chriss, Gorman, Garrett, Pous, Meyer and Norwood. The issues I address in rebuttal to these witnesses are: Construction Work in Progress, Reconciliation of Rate Base and Capital Structure, Appropriateness of Step Increases, Storm Damage Accruals, At-Risk Compensation, and Depreciation and Dismantlement.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes. I am sponsoring rebuttal Exhibit JTD-1. Exhibit JTD-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. For whom are you appearing as a rebuttal witness?

A. I am appearing as a rebuttal witness for Gulf Power Company (Gulf or the Company).

AT-RISK COMPENSATION

Q. What is OPC Witness Garrett's recommendation concerning the amount of at-risk compensation paid by Gulf to its employees?

A. Mr. Garrett refers to at-risk compensation as incentive pay and is recommending a disallowance of at-risk compensation related to financial performance measures and a further adjustment tied to customer satisfaction measures. If accepted, the effect of his recommendation would be to deny cost recovery of these costs on a going forward basis.

Q. Do you agree with Mr. Garrett's recommendation regarding at-risk compensation?

A. No, I do not. His recommendation is inconsistent with sound regulatory policy and basic principles of ratemaking, is contrary to Commission precedent, is based on simplistic assumptions that are not factually correct, and, if accepted, would be detrimental to the long term best interests of Gulf's customers.

Q. How is Mr. Garrett's recommendation inconsistent with sound regulatory policy and basic principles of ratemaking?

A. A fundamental tenet of sound regulatory policy is to provide recovery of all reasonable and necessary costs expected to be incurred to provide service to customers. And a basic principle of ratemaking is to include all such costs as test year expenses in calculating a regulated company's net operating income. Only if the Commission finds that the expenses in question are unreasonable, unnecessary or not expected to be incurred, should they be disallowed in calculating the company's revenue requirement.

Another fundamental tenet of sound regulatory policy is to encourage regulated utilities to be efficient and provide high quality service to their customers. Sacrificing efficiency and quality of service in the long run to achieve temporary rate reductions is not in the customers' interest. All regulatory decisions have consequences and good regulatory policy results when these consequences are adequately considered.

Mr. Garrett's recommendation violates both of these tenets of sound regulatory policy.

Q. How so?

A. First, Mr. Garrett makes no allegation that the amount of overall compensation paid to Gulf's employees, including at-risk compensation, is unreasonable, unnecessary or not expected to be incurred. Neither he, nor any other intervenor witness, has presented any analysis of the employment market to determine what amount of compensation is reasonable and necessary to attract the workforce needed to efficiently and reliably run an electric utility. This is in contrast to the testimony of Gulf Witness Garvie who explains that the overall compensation is reasonable, that it is necessary to attract and retain a qualified workforce, and that it is at or near the median of employee compensation paid by other regulated utilities.

The primary basis for Mr. Garrett's recommended disallowance is a belief that at-risk compensation tied to financial measures benefits shareholders more than ratepayers and therefore should be disallowed. He also argues for a further disallowance of at-risk amounts based on customer satisfaction goals. The inappropriateness of this further disallowance is addressed by Gulf Witnesses Strickland and Garvie in their rebuttal testimony. Ms. Strickland demonstrates that Gulf uses an appropriate survey tool to measure customer satisfaction and discusses Gulf's favorable customer satisfaction results from those surveys, while Mr. Garvie discusses the reasons why Mr. Garrett's suggested customer satisfaction disallowance should be rejected by this Commission.

Mr. Garrett does not analyze the net amount of compensation to employees that would result from his recommendations and fails to ascertain whether that net amount is reasonable. Consequently, Mr. Garrett's testimony is totally devoid of any consideration of the reasonableness of the net amount that he recommends or of the amount of compensation expected to be paid to employees. Mr. Garrett's recommendations appear to be driven primarily by a motivation to achieve lower immediate revenue requirements.

Q. What would be the longer term consequences of accepting Mr. Garrett's recommendations?

A. His recommendations would have longer term consequences that could affect efficiency and service, and his recommendations take away a valuable managerial tool that is effective in increasing efficiency and maintaining or improving the quality of service provided to customers.

Q. What do you mean by "takes away a managerial tool"?

A. If the Commission were to accept Mr. Garrett's recommendations, Gulf would be justified in rethinking its long standing approach to employee compensation. If a significant amount of otherwise valid and reasonable costs are disallowed not on the basis of the reasonableness of their amount but rather simply because of the method by which they are paid, Gulf would be justified in implementing a different pay structure that does not call into question the method by which these costs are paid. While accepting Mr. Garrett's recommendations would deny Gulf the opportunity to recover necessary costs currently, adopting a different compensation plan with no at-risk pay and a greater reliance on base pay would presumably eliminate the issue in future rate proceedings. But by moving more salary to base pay, employees would no longer have to re-earn that pay each year by meeting goals that typically include efficiency and service objectives. A compensation structure that pays employees regardless of performance diminishes management's leverage to motivate and focus employees on appropriate goals. In essence, the Commission would be substituting its judgment for that of Gulf's management as to how best to motivate and compensate its employees. Consequently, the incentive for Gulf's employees to be efficient and productive would be diminished.

Q. Is it your position that Commission precedent supports the recovery of at-risk pay tied to financial measures?

A. Yes, as I explain in more detail later in my testimony. While the Commission reviews each utility's compensation costs on the facts unique to that utility, the Commission has consistently recognized that at-risk pay is an accepted and desirable way to simultaneously achieve corporate goals and to control costs for the benefit of customers. The Commission has also determined that at-risk compensation is an appropriate component to include within overall compensation to judge whether the overall compensation paid to employees is reasonable.

Q. You understand Mr. Garrett is not recommending that Gulf not pay the at-risk compensation, he is just recommending it not be recovered in rates.

A. Yes, I understand his recommendation. However, disallowing a reasonable and necessary expense, or requiring the Company to pay part of the expense out of the return component that is intended to compensate investors for the use of their invested capital, is nothing more than a backdoor approach to reducing the allowed Return on Equity (ROE). Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in rates. The reduction to Gulf's ROE represented by Mr. Garrett's recommendation is significant—more than 100 basis points. This would significantly affect

Gulf's opportunity to earn what the Commission determines to be a fair rate of return.

Q. Mr. Garrett lists six points which he says form the rationale for excluding at-risk compensation tied to financial performance. Do you agree with those points?

A. No. First, Mr. Garrett's rationale does not recognize that the Company's at-risk compensation program is designed to provide a balance that benefits all stakeholders, including its customers, employees and investors. Further, the particular points cited as rationales represent hypothetical scenarios, include factual errors, and are counter to Commission precedent.

The Company's at-risk compensation programs include operational and financial goals designed to motivate employees to deliver quality services to customers, to improve operational efficiency, and to provide a fair return to investors. This balanced approach helps to ensure that the Company is sustainable and it provides benefits to each of the stakeholders, including in particular the customers.

Let me comment on each of Mr. Garrett's points.

(1) Payment is uncertain – Mr. Garrett asserts that an expense must be known with certainty before it can be recognized in rates. This is not the standard by which investment, expenses and revenues are recognized for rate setting purposes. The standard is to allow a reasonable level of investment and expenses which are necessary to provide safe and efficient service matched against reasonably expected revenues in the test year. The goal is to set rates which provide a reasonable opportunity for the utility to actually earn its authorized rate of return on a going forward basis. This is exactly what Gulf's compensation plan is designed to do.

The amount of overall compensation being requested by Gulf, including the portion which is at risk, is the amount of compensation reasonably necessary to provide safe and efficient service and thus should be recognized in rates. The fact that the amount actually paid to employees in a future year may be higher or lower than the amount recognized in the test year does not mean that the test year amount is unreasonable. This is true for all test year expenses and revenues, not just expenses associated with at-risk compensation.

A good example highlighting the fallacy of Mr. Garrett's argument concerning the need for certainty would be test year revenues. In this case, Gulf is projecting an increased level of revenues. As evidenced by the failure of revenues to materialize as projected in Gulf's last rate case, these revenues are not known with certainty. However, that does not mean that the level of projected revenue is unreasonable or not a proper basis on which to set rates on a going forward basis. The bottom line is that rates are set on a reasonable level of test year expenses and revenues and that Gulf assumes the risk of actually achieving its authorized return in a dynamic post-test year economic environment. The Company must control its costs and seek to increase revenues in this environment, and providing at-risk compensation is a valuable managerial tool for achieving these goals, which ultimately benefit customers.

(2) Many factors that impact earnings are outside the control of most company employees and have limited value to customers – It is obvious by this statement that Mr. Garrett totally misses the point of Gulf's overall compensation program. I do agree with Mr. Garrett that Gulf's employees cannot control the weather. What they can control to a meaningful degree is the amount of costs incurred to provide service in spite of the weather. In fact, it would be poor stewardship for Gulf's employees not to manage their expenses and investment to be able to operate within the actual revenues that result from variations in the weather. And while Gulf's employees cannot dictate economic conditions, they can make efforts to meet customer needs and provide mechanisms to obtain and retain customers despite the economic conditions.

Customers and this Commission should expect and encourage management to support such efforts. Gulf's at-risk compensation program is a vital managerial tool used by Gulf to meet the challenges of the weather and the economy. Eliminating this valuable managerial tool would be a disservice to Gulf's customers. Mr. Garrett also surmises that at-risk compensation can result in Gulf "securing an *unreasonably* high ROE." To imply that this Commission would allow an unreasonably high ROE because Gulf has an at-risk compensation program is insulting to the regulatory process in Florida. The point that Mr. Garrett so glaringly misses is a simple yet very meaningful one - it is not the purpose of Gulf's at-risk compensation program to secure an excessively high authorized ROE, rather it is a purpose of the at-risk compensation program to achieve efficiencies to better enable Gulf to actually achieve its authorized ROE, while still providing reliable service to its customers. This, in turn, is a significant benefit to customers.

(3) Earnings based goals in the at-risk compensation plans can discourage conservation – I have two comments regarding this assertion. First, in his point (2), Mr. Garrett states that Gulf employees cannot significantly impact growth in revenues and yet here he states that Gulf employees can have an impact on revenues by not supporting conservation programs. Which is it – Gulf employees can or cannot have an impact on revenues? Second, and more importantly, Mr. Garrett either is unaware or else totally ignores the Florida Energy Efficiency and Conservation Act (FEECA) and the manner in which the Commission has implemented it.

FEECA requires this Commission to set conservation goals and approve programs to meet those goals. Gulf is subject to the requirements of FEECA and must report to this Commission on its progress in meeting its goals. Failure to meet conservation goals can result in a penalty. To assert that Gulf would not support conservation efforts because of its at-risk compensation is not consistent with FEECA and the facts. This is true regardless of the cost-effectiveness test used by the Commission to evaluate and approve conservation goals. Nevertheless, the Commission has historically implemented FEECA with a focus on the Rate Impact Measure (RIM) test and has set goals accordingly. By definition, RIM passing measures minimize impacts on earnings and rates. Therefore, meeting conservation goals based on RIM passing measures, even using Mr. Garrett's faulty logic, cannot be asserted to be incompatible with at-risk compensation based on financial goals.

(4) The utility and its stockholders assume none of the financial risks associated with at-risk compensation payments – Once again, Mr. Garrett demonstrates his lack of understanding of the purpose and functioning of Gulf's at-risk compensation program. Mr. Garrett's assertion that "the company's only responsibility is to decide who gets the money, the stockholders or the employees" reflects simplistic assumptions and does not recognize the structure of the at-risk program or the realities of managing a regulated utility. The customers are only being asked to pay a reasonable amount in their rates for employee compensation, the same amount regardless of whether the compensation is fixed or variable. The annual risk of having to earn the portion of their compensation that is not base pay is squarely on the employees. It is the stockholders (and bondholders) that have provided capital to the Company and put it at risk. Therefore, the risk that unavoidable cost escalations or unavoidable declines in revenues will result in deficient earnings is squarely on the stockholders. Gulf's at-risk compensation program balances these risks between employees and stockholders with no risk being shifted to customers.

(5) At-risk compensation payments based on financial performance measures should be made out of increased earnings – It is unclear what Mr. Garrett means by "increased earnings." It is possible that he means the increased earnings that may result from efficiencies produced by virtue of the employee incentives contained within Gulf's compensation program. However, Mr. Garrett, in his point (2), states that Gulf employees cannot significantly impact earnings. If that is the case, I am at a loss how he could possibly argue that at-risk payments should be made from earnings that the at-risk mechanism played no part in creating. And if the increased earnings did in fact result from efficiencies created by the incentives within the compensation program, why would one want to neuter the effectiveness of a program which creates efficiencies that ultimately benefit customers? Obviously one would not want to do so, yet this would be the effect of adopting Mr. Garrett's recommendations.

Of course, Mr. Garrett's meaning for "increased earnings" may be a potential increase in earnings that result outside of the at-risk compensation mechanism. If that is his meaning, Mr. Garrett, in effect, is proposing a fundamental and one-sided shift in the regulatory paradigm that has served Florida so well over the previous forty plus years. Absent a specified reward or penalty in setting rates, Florida establishes a 100 basis point band above and below the midpoint and the midpoint becomes the rate-setting point. Rates are set to cover 100% of all reasonable and necessary costs so as to give the utility a reasonable opportunity to actually earn its authorized return (mid-point). If actual earnings exceed the midpoint up to the upper end of the band, a regulated utility is rewarded with those earnings. This acts as an incentive. Likewise, a utility earning below the midpoint to the bottom of its range is expected to "make do" with that earnings level because those earnings are still considered reasonable. In that situation, the utility still has an incentive to increase efficiencies to avoid a rate case and to potentially earn a higher return within its authorized range.

Mr. Garrett would fundamentally change this symmetrical incentive-based mechanism. First, and most importantly, he recommends that a significant portion of compensation costs be disallowed in setting rates. This immediately places Gulf in a hole and in jeopardy of not earning a reasonable return. The size of the "hole" is slightly over 100 basis points, or roughly the size of the band on either side of the midpoint. So the size of the hole is very significant! He then suggests that an undefined amount of "increased earnings" be used to pay the component of compensation expense that he recommends be disallowed in rates. This would require Gulf to somehow find means to generate additional earnings to make up for its already large deficient position and then to pay the at–risk compensation that Mr. Garrett recommends be disallowed in rates. This inappropriately lessens the incentive for utilities to reduce costs or otherwise produce efficiencies for customers' long term benefit. This result is inconsistent with Florida's practice and good regulatory policy and should be rejected.

(6) At-risk compensation payments embedded in rates shelter the utility against the risk of earnings erosion through attrition – At a theoretical level I can agree that at-risk compensation can have the benefit of mitigating earnings erosion through attrition. However, this theoretical aspect of at-risk compensation not only benefits a utility, it greatly benefits the utility's customers by potentially stabilizing rates and postponing rate cases. In fact, in the late 1970's and the early 1980's, the Commission routinely granted specific increments in rates referred to as attrition allowances, to help stabilize rates and decrease the frequency of rate cases.

Unfortunately, this theoretical aspect of Gulf's at-risk compensation plan has not had the real world benefits that Mr. Garrett portrays. First, as explained in the testimony of Gulf Witness Teel, Gulf's earnings have not been at or above the bottom of its authorized range for an extended period of time. So despite having an at-risk compensation program, earnings attrition has not been eliminated for Gulf. Second, the attrition mitigating benefit of any at-risk compensation program cannot be called upon year after year. If this were the case, Gulf's employees would be compensated below market for an extended period. This is a scenario that cannot be sustained without consequences harmful to customers. Third, the limited attrition benefits are achieved only if the full amount of at-risk compensation is allowed in rates, which is not Mr. Garrett's proposal. In fact, Mr. Garrett's proposal would disallow recovery of $12 million of compensation costs, resulting in a significant reduction in Gulf's earned ROE on a financial reporting basis.

Mr. Garrett would have the Commission believe that such a large disallowance can be made without consequence and that Gulf can continue to pay its employees at levels not supported in its rates. This certainly is not reality.

Q. Mr. Garrett makes the statement that even if it is assumed a utility needs to pay the at-risk compensation to attract and retain qualified personnel, it does not follow that those costs should be recovered in rates. Do you agree with that statement?

A. No. I do not. First, it is clear from Mr. Garrett's testimony that at-risk compensation as part of the overall compensation to employees is a necessary expense. Mr. Garrett claims that utilities in other jurisdictions generally pay at-risk compensation based on financial measures even if they are currently not permitted recovery in rates. This is evidence that these are necessary expenses that must be incurred for the utility to attract and retain qualified personnel.

The gist of Mr. Garrett's recommendation is if other states have disallowed a portion of compensation tied to financial measures and that compensation is still paid by the utility, then it is not a cost that should be recovered in rates. This recommendation violates one of the most basic tenets of regulatory theory, i.e., that all necessary and prudent costs should be allowed to be recovered in rates.

Q. Isn't it true, as Mr. Garrett says, that disallowing the at-risk compensation tied to financial measures will put Gulf "on an even playing field with other utilities with respect to compensation costs"?

A. No, this is not true. In Mr. Garrett's testimony, even for other utilities whose at-risk compensation may not be included in rates, he does not describe the magnitude of the disallowance or the impact on the other utilities' ability to achieve their allowed ROE. Mr. Garrett also fails to consider the fact that Gulf must also compete for employees with non-regulated firms that recruit and retain employees on market conditions and not "regulatory policy". While I firmly believe that regulatory policy has an important place in this country's economy, it simply does not trump competitive forces at play in the country's labor market, for either regulated or non-regulated businesses. But more importantly, what some other jurisdictions may decide is irrelevant to a determination of whether Gulf's at-risk compensation is a prudent and necessary cost of providing utility service.

Q. Another basis for your disagreement with Mr. Garrett is that his recommendation is contrary to Commission precedent. How can that be the case when he has cited two Commission decisions that excluded incentive compensation based on financial measures?

A. Neither of the orders cited by Mr. Garrett became final orders of the Commission and therefore have no meaningful precedential value. These orders were either on reconsideration or appeal when the cases were settled by the parties. Further, these non-final decisions were aberrations of the Commission's long standing policy that had been adopted and consistently applied. In a Gulf case subsequent to these cases the Commission again followed the long standing policy of including the at-risk compensation that was determined to be at or near the median of the market for the same or similar employees. Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, In re: Petition for increase in rates by Gulf Power Company.

Q. What has been the Commission's policy?

A. The Commission has had a long history of approving incentive compensation as a proper cost to be afforded recovery in rates. While reviewing each utility's incentive compensation costs on the facts unique to that utility, the Commission has consistently recognized that incentive compensation is an accepted and desirable way to achieve corporate goals and to control costs for the benefit of customers. The Commission has also determined that incentive compensation is an appropriate component to include within overall compensation to judge whether the overall compensation paid to employees is reasonable.

Q. What Commission decisions reflect this long-standing policy?

A. There are several, starting with a Florida Power Corporation rate case that provided for cost recovery of incentive compensation finding that: "Incentive plans that are tied to achievement of corporate goals are appropriate and provide an incentive to control costs." Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In re: Petition for a rate increase by Florida Power Corporation. In a Tampa Electric case decided in 2009, the Commission found that Tampa Electric's total compensation package, including the component contingent on achieving incentive goals, was set near the median level of benchmarked compensation and allowed recovery of incentive compensation that was directly tied to results of Tampa Electric:

> Tampa Electric's Success Sharing Plan has been in place since 1990 and its appropriateness was approved in the Company's last rate case in 1992. Lowering or eliminating the incentive compensation would mean Tampa Electric employees would be compensated below the employees at other Companies, which would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce. We therefore decline to do so.

Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for a rate increase by Tampa Electric Company.

The Commission has also approved incentive compensation in three prior rate cases for Gulf Power Company, the most recent of which was the April 3, 2012, order I have already mentioned. The Commission's finding in the 2001 Gulf rate case contains language similar to the Tampa Electric case:

> To only receive a base salary would mean Gulf employees would be compensated at a lower level than employees at other companies. Therefore, an incentive pay plan is necessary for Gulf salaries to be competitive in the market.

Another benefit of the plan is that 25% of an individual employee's salary must be re-earned each year. Therefore, each employee must excel to achieve a higher salary. When employees excel, we believe that the customers benefit from a higher quality of service.

Order No. PSC-02-0787-FOF-EI, in Docket 010949-EI, In re: Request for rate increase by Gulf Power Company (page 45 of order).

Q. Are there any Florida Court decisions relevant to the issue of Commission disallowance of compensation expenses?

A. Yes, two cases are instructive in this regard and both dealt with the Commission's disallowance of executive compensation.

In *Florida Bridge Company v. Bevis*, the Florida Supreme Court reversed a decision of the Commission disallowing a portion of the company president's salary. The Court observed:

> Indeed, the Commission has made no attempt to determine whether the president's compensation is excessive in view of the services he provides. The arbitrary ratio by which the Commission reduced the salary and expense account[,] the ratio of days physically absent from the home office to the total number of workdays in the test year[,] has no support in logic, precedent, or policy. 363 So. 2d 799, 800-01 (Fla. 1978).

The Court found the Commission's action "was arbitrary and constitutes a substantial departure from the essential requirements of law." *Id.*

The First District Court of Appeal reached a similar conclusion in *Sunshine Utilities of Central Florida, Inc. v. Florida Public Service Commission*, in finding fault with the Commission's disallowance of a portion of the company president's salary:

> In determining whether an executive's salary is reasonable compared to salaries paid to other company executives, the comparison must, at a minimum, be based on a showing of similar duties, activities, and responsibilities in the person receiving the salary. 624 So. 2d 306, 311 (Fla. 1st DCA 1993).

Q. How are these cases related to the disallowance of at-risk compensation recommended by Mr. Garrett?

A. It relates to the point I made earlier in my testimony regarding the need to determine whether overall compensation expense is reasonable and necessary. The Florida Supreme Court and the First District Court of Appeal reversed the Commission's decisions because the basis for the disallowances did not address the reasonableness of the salaries as compared to the market.

Mr. Garrett's analysis is similarly flawed because he has made no attempt to compare the total compensation paid to Gulf employees to the market for similar services, duties, activities and responsibilities. Nor has he, or any other intervenor witness, presented evidence that the salaries for any employee are excessive. Instead, he recommends a portion be disallowed based on <u>how</u> it is paid. Because it is at-risk, rather than base salary, he erroneously contends that it should be disallowed notwithstanding whether the total amount of compensation is reasonable. The focus of any disallowance should be <u>how much</u> is paid, not <u>how</u> it is paid, particularly so when use of at-risk pay keeps the utility market-competitive and drives employee behavior that should work as a benefit to customers.

Q. Why has this been the long standing policy of the Commission?

A. I believe there are a number of reasons for this. First, the Commission's policy is consistent with the basic tenets of sound regulatory policy which I described earlier. Second, the Commission has recognized that having good management at utilities is essential for regulators to achieve their mission of having safe, reliable and reasonably-priced service delivered to customers. The Commission has further understood that management needs sufficient tools and incentives to achieve these goals and that regulators should not attempt to "micro-manage" their regulated utilities. And third, the Commission has appropriately recognized that not all issues in a rate proceeding are a simple situation of "us vs. them," where every issue has a clear winner and a clear loser. While incentive compensation has been and is currently being characterized as an "us vs. them" issue, in reality it is not. Incentive compensation is a good example of a "win-win" situation.

Q. What do you mean by a "win-win" situation?

A. At-risk compensation is a situation where all stakeholders win. Shareholders get to invest in a company with employees motivated to achieve appropriate corporate goals. Management gets to apply compensation tools that they think are best to motivate and fairly compensate employees. And most importantly, customers pay no more than a reasonable amount in their rates but get a work force that is motivated to be efficient, to reduce costs where possible, and to maintain a high level of safe and reliable service.

Q. The underlying rationale for Mr. Garrett's recommendation is that at-risk payments related to financial performance primarily benefit shareholders and therefore should be excluded for ratemaking purposes. Do you agree?

A. No, I do not. Financial goals also benefit customers. Regulated utilities are profit making entities (hopefully) and must make a reasonable profit to be sustainable and to access capital when needed and on reasonable terms. This is the means by which customers receive the service that they expect and deserve. A utility earning a reasonable profit is beneficial for both its shareholders and its customers. A financially healthy utility benefits all of its stakeholders - customers, employees and investors – by delivering quality service and earning a fair return on investment. A utility's ability to earn a fair return assists in attracting the capital required to provide services to the customer. A financially healthy utility provides access to capital on reasonable terms and provides the ability to withstand financial adversity. A financially healthy utility will also provide a lower cost of funds for necessary infrastructure investment, resulting in a lower price for the customer. Also, a financially healthy utility demonstrates its ability to deliver efficient operations and to benefit customers, employees and investors. These benefits are consistent with the goals of the Commission. In Gulf's last rate case the Commission specifically recognized that ratepayers benefit from Gulf and Southern Company maintaining a healthy financial position. Order No. PSC 12-0179-FOF-EI at 94-95.

Q. Does Mr. Garrett believe that ratepayers benefit from a financially healthy utility company?

A. Mr. Garrett's testimony indicates his recognition that ratepayers can receive some benefit from having a financially healthy utility and that some states acknowledge that ratepayers benefit from financial-based incentives. Although he acknowledges these points, he minimizes that consideration in his recommendation. These benefits to customers are manifested in both the ability to raise capital on good terms as well as operational benefits. A good example of how financial-based incentives can provide operational benefits for customers is return on equity (ROE), a generally accepted means of measuring financial performance and a component of Gulf's at-risk compensation program. ROE represents the earnings (revenues less expenses) as a percentage of equity investment. It can be increased (or its erosion diminished over time) in a number of ways. First, revenues can be increased by serving more customers with the same amount of expenses and investment. Second, expenses can be reduced by serving existing and future customers more efficiently. Third, assets can be utilized more efficiently so that the denominator in the equation (equity capital) is minimized for each dollar of income that is generated. Each of these scenarios (or a combination of them) will increase the ROE and provide added value to customers by increasing the efficiency of utility operations. This is particularly meaningful for regulated utilities which must keep rates fixed in between rate cases.

Q. Is it appropriate to allow recovery of at-risk compensation based on the achievement of financial goals?

A. Yes, it is.

Q. Is this also true for the long term portion of Gulf's at-risk compensation?

A. Yes, it is. My testimony concerning the appropriateness and the associated customer benefits of at-risk compensation based on financial goals applies equally to both short term and long term compensation. Once again, the test is whether the total amount of compensation, that is the combination of both base and at-risk pay, is reasonable. As Mr. Garvie states in his testimony, the long term portion of Gulf's at-risk compensation is part of a balanced compensation plan and when combined with short term at-risk compensation and base pay, the entire amount of compensation is at the median of the market. Therefore, customers get the benefits of motivated and focused utility employees and are paying no more than the market level of overall compensation. Including long term financial-based goals as a part of a total compensation plan is particularly important for customers.

Q. Why are long term goals important for customers?

A. They balance the short term perspective with a longer term one. This leads to better decision making which insures that customer benefits are obtained and maintained into future years. Successful utilities which best serve the interests of customers are required to plan well into the future and must obtain capital to invest in needed infrastructure with lives sometimes exceeding 40 years. It is imperative that managers maintain their focus on both the short term and the long term. While Mr. Garrett and I disagree on many points, this is one in which we share a common view. When referencing the potential of decision making being too focused on short term goals, Mr. Garrett states: "Decisions of this type may benefit shareholders in the short run, yet they put ratepayers at risk in the long run", clearly conceding that long term considerations are in the customers' best interest.

Q. Another basis for Mr. Garrett's recommendation to disallow at-risk compensation tied to financial measures is that other states have excluded this compensation for ratemaking purposes, therefore Florida should also. Do you agree with that rationale?

A. No, absolutely not. A reasonable, justified cost is just that, regardless of what another jurisdiction may say. Whether an expense should be recovered depends on the evidence in the case. Only if the Commission finds that the expense in question is unreasonable, unnecessary or not expected to be incurred should it be disallowed.

Q. Are you aware that Mr. Garrett alleges that the disallowance of compensation related to financial performance is "the general rule followed in most states"?

A. Yes, I am aware of his allegation. I am unaware as to whether his assertion that the disallowance is followed as a general rule is correct. I would hope that each jurisdiction would make its decision on the specific facts and unique circumstances that exist in each case and not merely resort to an alleged general or conventional rule. In this regard, I am reminded of the quote from John Kenneth Galbraith, a renowned economist and advisor to numerous U. S. Presidents: "The conventional view serves to protect us from the painful job of thinking." The question of allowing or disallowing at-risk compensation is a question of looking at the evidence and determining whether the requested compensation is reasonable and necessary. The decision in this case could have profound consequences on regulatory policy and managerial decisions that may follow as a result. I would encourage the Commission to find little comfort in the decisions of other jurisdictions on this issue and get on with the "job of thinking" this issue through on the evidence and what is in the customers' best long term interest.

DEPRECIATION & DISMANTLEMENT

Q. What is Gulf proposing for depreciation and dismantlement in this case?

A. Gulf is basing its proposal on the results of current depreciation and dismantlement studies that were filed with the Commission pursuant to the normal schedule as prescribed in Commission Rules 25-6.0436 and 25-6.04364. Based on these studies, Gulf is proposing a slight increase in depreciation expense and a significant reduction in dismantlement expense, resulting in an overall net reduction of $297,000.

Q. What is OPC Witness Pous proposing?

A. Mr. Pous proposes to reduce Gulf's requested amount of depreciation and dismantlement expense by $19.986 million on a total company basis. After adjusting for items recovered through clauses, he proposes a net reduction of $14.133 million.

Q. Did Mr. Pous perform his own comprehensive studies?

A. If he did, he did not present them in his testimony. He limited his approach to making twenty-three adjustments to Gulf's comprehensive studies. Mr. Pous criticizes various aspects of the comprehensive studies presented by Gulf and substitutes his judgment for the lives and salvage values for a number of specific accounts.

There are two aspects of Mr. Pous' adjustments that I find striking. First, although he makes 23 adjustments to Gulf's comprehensive depreciation and dismantlement studies, he fails to acknowledge that he is in apparent agreement with (or at least failed to make adjustments to) many more aspects of those studies. In weighing his explicit criticisms of Gulf's comprehensive studies, the Commission should be aware that there are more proposals put forth by the Company with which Mr. Pous apparently agrees than there are with which he disagrees.

Second, it should be noted that 100% of Mr. Pous' adjustments work to reduce Gulf's depreciation and dismantlement expense. While there can be legitimate differences in judgment, particularly in the area of depreciation, one would expect that an unbiased review would reveal areas of disagreement working in both directions.

Q. Are you suggesting that Mr. Pous was biased in his review?

A. No, I stop short of that conclusion. I am merely observing that in my experience, truly unbiased depreciation analyses have adjustments working in both directions. I also observe that Mr. Pous apparently has a general prejudicial attitude to the effect that utilities cannot be trusted to prepare unbiased depreciation studies.

Q. What is the basis of your observation?

A. I am referring to Mr. Pous' testimony, specifically Page 8, Lines 2-18. In this testimony, he surmises that utilities cannot be trusted to perform unbiased depreciation studies because "it is an electric utility's financial self-interest to collect more dollars from customers than fewer dollars, to collect those dollars sooner than later and, once having collected the dollars, to keep them rather than returning them to customers." He continues and then concludes, "a utility has an incentive to favor higher depreciation expense and higher depreciation reserves."

Q. Do you agree with Mr. Pous' position?

A. No, I emphatically disagree, for both policy and factual reasons. First it needs to be reiterated and emphasized that depreciation expense provides no profit motive for a regulated utility. To the contrary, higher than necessary depreciation expenses and depreciation reserves act to prematurely reduce a regulated utility's rate base. And it is the rate base upon which a regulated utility is permitted the opportunity to earn a reasonable return. Thus, a regulated utility actually has a disincentive to have higher than appropriate depreciation expenses, because they prematurely erode the basis upon which profits are earned. Regulated utilities also have a disincentive to set depreciation rates too low. If depreciation rates are too low, investment remains on the utility's books after the associated assets have ceased providing service, which can result in depreciation reserve deficiencies. Such deficiencies are not in the long term interests of utilities or the customers they serve.

Q. What has been your experience with Gulf's depreciation practices?

A. Gulf has consistently followed the Commission's Rules on the timing and content of depreciation studies. I have detected no inherent biases in their studies and approaches. This is not to say that their studies and depreciation rates were not scrutinized and adjusted appropriately. Any adjustments were generally consistent with the unbiased recommendations of Commission Staff and such adjustments were routinely made in both directions, as the facts and associated judgments dictated. And normally, these adjustments were objectively made outside the confines of a rate case, without the distractions of immediate rate case impacts.

Q. You stated that they were normally done on the schedule as set forth by rule and not within the confines of a rate case. Is it inappropriate to consider depreciation studies in the context of a rate case?

A. No, not at all. If the timing of a required depreciation study and a rate case coincide, it is appropriate to consider them together. However, it is critically important that the depreciation study and the resulting depreciation rates be objectively analyzed and objectively set. Impacts on customer rates (up or down) should not be a consideration. The depreciation study should stand on its own merits. If depreciation rates were set too low simply to result in lower customer rates in the rate case, it would have negative consequences for customers in the long term.

Q. What would be the negative consequences?

A. There would be several. First, customer rates would be set lower than the true cost of providing service and would send inappropriate price signals. Second, rate base would be higher than it otherwise should be, requiring both higher depreciation rates and higher customer rates in the future. Third, it is possible that assets would remain in rate base after they have ceased to provide service to customers. And fourth, a theoretical depreciation reserve deficiency would likely result. While theoretical reserve imbalances are to be expected, they should be the result of unanticipated changes in lives, salvage values, and other projection parameters, not the result of attempts to keep rates lower than what is economically justified.

Q. You stated that depreciation reserve imbalances are to be expected. What is the current status of Gulf's depreciation reserve?

A. Gulf currently has a theoretical reserve deficiency of $26.9 million. According to Gulf Witness Huck, the Company's entire accumulated depreciation balance of $1.369 billion is only 2% below the theoretical reserve balance.

Q. What does this indicate to you?

A. It indicates that despite consistent efforts to objectively set depreciation rates, imbalances do occur. It further indicates that Gulf has not been biased in their studies (to overstate depreciation rates) and that Staff has effectively scrutinized Gulf's studies in the past.

Q. Should the fact that Gulf's depreciation reserve is deficient concern the Commission?

A. No, not necessarily. The Commission should certainly be aware of its deficient status, but should also find comfort in the facts that (a) the theoretical reserve imbalance is very small and (b) the remaining life depreciation method utilized by the Commission is a self-correcting one. If depreciation rates are objectively set every four years, the reserve deficiency will self-correct over the remaining lives of the assets involved. However, if depreciation rates are set artificially low to minimize rate case impacts, the reserve deficiency will only be exacerbated. This would not be in the customers' best long term interests.

Q. Should the depreciation reserve deficiency be amortized over four years to insure that it is addressed?

A. No, I believe the Commission should rely on the self-correcting nature of the remaining life method.

Q. Does Mr. Pous address the depreciation reserve deficiency in his testimony?

A. Yes, he acknowledges that there is an imbalance, but does not indicate whether he believes it is in a surplus or deficient position. He characterizes it as being insignificant and concludes that it should not be amortized.

Q. Has Mr. Pous previously addressed depreciation reserve imbalances before this Commission?

A. Yes, he testified in the 2008 rate cases of Florida Power & Light Company and Progress Energy Florida. In both of these cases he advocated for a rapid amortization of theoretical reserve surpluses. This had the effect of immediately and significantly reducing customer rates in those rate cases. Amortizing Gulf's reserve deficiency in this case would have the opposite effect, i.e., would increase customer rates.

Q. Please put the dismantlement dispute in this case in context.

A. Gulf's current dismantlement rates were approved by the Commission in

2010 after submission of a dismantlement study by Gulf, which was largely accepted by the Commission. Order No. PSC-10-0458-PAA-EI. If Gulf's dismantlement expenses were computed under that Order, they would total $9,591,938.

In May of 2013, pursuant to Rule 25-6.04364, Florida Administrative Code, Gulf filed a new Dismantlement Study. Under this study Gulf's proposed dismantlement expenses total $7,023,336. So, under its pending dismantlement study, Gulf dismantlement expense declines by approximately $2.6 million.

Mr. Pous proposes two adjustments to Gulf's proposed dismantlement expense that would lower Gulf's dismantlement expense by another $6,288,508 to only $734,828.

So, Gulf has proposed a reduction from current dismantlement expense of 27%. Mr. Pous proposes an adjustment from current dismantlement expense of 92%. The size of Mr. Pous' adjustment from a level of expense that comes from a Commission-approved dismantlement study just four years old should give an objective observer some pause.

Q. Aside from the significant magnitude of Mr. Pous' dismantlement adjustments, do you have any other concerns with Mr. Pous' two proposed dismantlement adjustments?

A. Yes. Both of his specific adjustments are of questionable merit.

His first adjustment, totaling some $4,832,835, results from his criticism of the Company using an escalation of dismantlement costs into the future and then discounting those costs back to present value. He mischaracterizes those calculations as "manipulation of estimated future inflation and discounting." Instead, he should have acknowledged that Gulf's methodology follows the Commission's dismantlement rule and orders, which require both the dismantlement cost escalation and discounting he criticizes. What Mr. Pous mischaracterizes as "manipulation" is really compliance with the Commission's dismantlement rule.

His second adjustment is to remove any percentage contingency from the dismantlement cost estimate. Gulf employed a 10% contingency, and Mr. Pous proposes a "zero (0) level of contingency." The 10% contingency proposed by Gulf is below the dismantlement contingencies approved for other Florida utilities. This highlights the fact that Mr. Pous' zero contingency is woefully inadequate.

Q. Please elaborate on your conclusion that Mr. Pous' criticism of Gulf's dismantlement methodology is really a criticism of the Commission's dismantlement rule and dismantlement order.

A. Over the period 1989 through 1991, in Docket No. 24741, the Commission conducted an investigation into the rate making and accounting treatment for the dismantlement of fossil generating units. In its Order No. 890186-EI, the Commission set forth its policy regarding dismantlement studies. In regard to what Mr. Pous has mischaracterized as data manipulation, the

Commission had this to say about how dismantlement accruals should be developed:

> The accruals should be based upon the current cost estimates contained in the dismantlement studies, escalated to future costs through the time of the dismantlement. The future costs less amounts recovered to date should then be discounted in a manner that accrues the costs over the remaining life span of the plant.

This approach of escalating current dismantlement estimates and then discounting them is precisely the methodology followed in Gulf's dismantlement study. It is the approach that Mr. Pous mischaracterizes as "manipulation of data."

In 2003, the Commission codified its dismantlement policy into a rule, Rule 25-6.04364, Electric Utilities Dismantlement Studies. Many of the provisions from Order 890186-EI found their way into the Commission's dismantlement rule. In regard to what Mr. Pous has mischaracterized as "data manipulation," subsection (4) of the dismantlement rule provides:

> (4) The dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement. The future costs less amounts recovered to date shall then be discounted in a manner that accrues the costs over the remaining life span of the unit.

Once again, that is precisely the methodology Gulf followed in its dismantlement study, and it is this approach that Mr. Pous repeatedly mischaracterizes and criticizes as "manipulation of data."

Mr. Pous spends a great deal of effort in his testimony criticizing this aspect of Gulf's dismantlement study (see pages 34-40). Over those seven pages of methodological critique, he not once refers to the Commission's dismantlement rule or Order No. 890186-EI. Mr. Pous is apparently unfamiliar with the Commission's dismantlement rule and policy or simply chooses to ignore them. In either event, Mr. Pous' criticism of Gulf's dismantlement methodology is really a criticism of a Commission policy that has been adopted as a rule. His $4.8 million dollar adjustment to Gulf's dismantlement cost is inconsistent with Commission policy and should be rejected. Gulf should not have its dismantlement amount rejected for following the Commission's dismantlement rule.

Q. You have also testified that Mr. Pous' second adjustment to Gulf's dismantlement cost is of questionable merit. Please elaborate.

A. Mr. Pous' second adjustment is to remove any percentage contingency from the dismantlement cost estimate and the resulting dismantlement expense. Once again, this is at odds with the Commission's dismantlement rule as well as prior Commission decisions approving other dismantlement costs.

The Commission's dismantlement rule clearly contemplates that the dismantlement studies submitted pursuant to the rule will contain an allowance for contingency. Subsection (3) (m) of Rule 25-6.04364 provides in pertinent part:

> Each utility's dismantlement study shall include:
>
> (m) Supporting schedules, analyses, and data, including the contingency allowance used in the developing the dismantlement cost estimates and annual accruals proposed by the utility.

Mr. Pous' proposed disallowance of all of Gulf's contingency costs is at odds with Rule 25-6.04364.

It should also be noted that Mr. Pous' suggested zero allowance for contingency is at odds with several recent Commission orders approving positive contingency values in excess of Gulf's 10% value.

Q. What are the orders to which you refer?

A. There are three orders to which I refer. The first is Order No. PSC-10-0131-FOF-EI for Progress Energy Florida which set a 20% contingency factor. The second is Order No. PSC-10-0153-FOF-EI for Florida Power & Light Company which set a 16% contingency factor. The third is Order No. PSC-12-0175-PAA-EI for Tampa Electric Company which set a 15% contingency factor.

Q. Has the Office of Public Counsel (OPC) previously taken issue with Gulf's use of a 10% contingency factor?

A. Yes, during Gulf's last dismantlement study review in Docket No. 090319-

EI, the OPC asserted that the contingency factor should be set at zero and by no means greater than 5%.

Q. What did the Commission decide in that case?

A. In Order No. PSC-10-0458-PAA-EI, the Commission disagreed with OPC's position and found that a 10% contingency "is very reasonable in light of our prior decisions."

Q. Was the Commission's support for a contingency factor of 10% limited to its reference to previous decisions?

A. No. The Commission noted that "contingency factors are found in nearly all engineering, consulting, construction, and demolition estimates as an appropriate provision in cost estimates." The Commission went on to cite the American Association of Cost Engineers' Notebook and its definition of a contingency. The Commission also stated that contingency factors are used to "assure that adequate funds are available in the event that something unpredictable, as well as costly, occurs while in the process of dismantling a fossil-fueled generating plant."

Q. Please summarize your rebuttal of Mr. Pous' dismantlement disallowances.

A. They are without merit. They are inconsistent with the Commission's dismantlement policy, the Commission's dismantlement rule and prior Commission decisions. Following Commission rules regarding Dismantlement accruals should not be grounds for rejecting Gulf's proposal.

CONSTRUCTION WORK IN PROGRESS (CWIP)

Q. What is Wal-Mart Witness Chriss recommending for CWIP for Gulf?

A. Mr. Chriss recommends that $26.656 million of CWIP be excluded from Gulf's rate base and be denied a return.

Q. Did Mr. Chriss take a similar position in Gulf's last rate case?

A. Yes, he did. While the dollar amounts have changed, his argument for excluding CWIP from rate base remains the same.

Q. What was the Commission's decision concerning Mr. Chriss' recommendation to exclude CWIP from rate base?

A. The Commission rejected Mr. Chriss' recommendation.

Q. What is CWIP?

A. CWIP is FERC Account 107 which reflects the total of work order balances for electric plant that is in the process of being constructed.

Q. Is CWIP a necessary part of providing quality service?

A. Yes, it is. A well managed utility focused on providing quality and cost effective service will deploy capital to construct new and/or modernize existing facilities to meet these objectives.

Q. Recognizing that CWIP is a necessary part of providing quality utility service, should it be permitted to earn a return?
A. Yes, it should.

Q. How should this be accomplished?
A. It should be accomplished in one of two ways. First, balances in CWIP could be allowed to accrue on Allowances for Funds Used During Construction (AFUDC). The Commission has adopted Rule 25-6.0141, F.A.C., which sets forth the calculation of AFUDC and the eligibility requirements of those construction projects which qualify. The second way is to allow CWIP in rate base.

Q. Is there a fundamental difference between the two approaches?
A. Yes, there is. Accruing AFUDC adds to the capital costs of a project. The return is an accounting entry only and is actually realized when the capital asset is included in rate base and is depreciated. Including CWIP in rate base avoids increasing the capital cost of the project through AFUDC and earns a return in rates while the project is being constructed.

Q. What are the main reasons why a CWIP project would not qualify for AFUDC?
A. There are two main reasons. First, under the Commission's AFUDC rule, if the project's construction period is less than 12 months, it does not qualify. Second, if the project is allowed in rate base, it does not qualify for AFUDC.

Q. If the Commission were to adopt Mr. Chriss' position, would a return on CWIP be denied?

A. Yes, the $26.656 million represents short-term construction projects which do not qualify for AFUDC under the Commission's rule. If these projects are not included in rate base, Gulf will be denied an opportunity to earn a return on capital that it has deployed to adequately meet its customers' need for service.

Q. Mr. Chriss rationalizes his recommended disallowance on the grounds that the $26.656 million is not used and useful. Do you agree?

A. No, I do not. First, it needs to be understood that an accounting classification does not mean that invested amounts are not providing benefits to customers. Customers expect and deserve to have facilities in place to serve them when needed and to modernize existing facilities when it is cost-effective and/or improves service. In fact, if Gulf did not make these investments, it could be sanctioned by the Commission for not doing so.

Second, capital projects take time to construct, some longer than others. Costs are incurred to carry these projects to their ultimate completion. A project with a construction time of less than 12 months still incurs these carrying costs and these costs should be recognized in setting rates. Not doing so would be analogous to a bank not having to pay interest on CDs of less than 12 months. Obviously, investors expect a return on capital for the entire time that it is invested, not for just when it exceeds 12 months.

Third, labeling an investment as "not used or useful" does not mean that it should automatically be excluded from rate base and denied the opportunity to earn a return. The Commission, in adopting Rule 25-6.041, F.A.C., recognizes that CWIP can be allowed in rate base. Even long-term projects that otherwise would qualify for AFUDC can be included in rate base to maintain a utility's financial integrity.

Q. How is financial integrity threatened by large amounts of CWIP?

A. A large construction program can put financial strains on a utility, even if AFUDC is allowed. AFUDC is a non-cash accounting entry with delayed realization of earnings. With insufficient cash flows, bond ratings can be threatened. In addition, denying both AFUDC and rate base inclusion, as Mr. Chriss suggests, would only exacerbate potential negative financial impacts.

Q. Has the Commission allowed the inclusion in rate base of CWIP which is ineligible for AFUDC?

A. Yes, this is the Commission's established practice. The Commission has acknowledged that short term construction projects are a necessary part of providing quality service and should be allowed in rate base as opposed to accruing AFUDC.

Q. Has the Commission ever conducted an investigation into the proper accounting and ratemaking treatment for CWIP?

A. Yes, the Commission conducted such an investigation in Docket No. 72609-PU and issued its findings in Order No. 6640, dated April 28, 1975.

Q. What were the Commission's findings?

A. The Commission reaffirmed its previous findings that there should be two (and only two) options for CWIP. The Commission stated:

> The Commission's currently prescribed accounting treatment of AFDC was established by Order No. 3143 in Docket No. 6655 issued in 1962. It provides the companies with two options:
>
> a. Charge AFDC on CWIP and not include CWIP in rate base.
>
> b. Not charge AFDC and include CWIP in rate base.

Q. Did the Commission address the proper treatment of construction projects with shorter construction times?

A. Yes, the Commission did and generally referred to such projects as "blanket work orders", recognizing that such projects were generally not great in individual dollar amounts, and were routine or recurring in nature. Such projects were accounted for on a blanket work order basis.

Q. What did the Commission decide for these types of projects?

A. The Commission recognized that such projects generally do not receive AFUDC and thus should be included in rate base. The Commission stated:

Due to the differences in operating characteristics of the various companies, we deem it inappropriate and impractical to attempt to set a standard for the dollar amount or time span that would be used to determine the eligibility of certain construction projects as blanket work orders. However, since blanket work orders do not receive AFDC and thus are permitted under our optional provisions of being included in the rate base, we believe the levels set by the companies should be reviewed by this Commission for purposes of testing their reasonableness.

It should also be emphasized that in order to be eligible for inclusion in the rate base, blanket work orders should not receive AFDC at any time, either in the past or future.

Q. Has the $26.656 million of CWIP that Gulf is requesting to be included in its rate base ever accrued AFUDC?

A. No, it has not and therefore, should be included in Gulf's rate base.

Q. Mr. Chriss asserts that the inclusion of CWIP in rate base shifts the risks traditionally assumed by investors to ratepayers. Do you agree with his rationale?

A. I do not agree. There is no shifting of risk. Investors have put their capital at risk by investing capital in a utility and are justifiably seeking a return, either through rate base inclusion or through the accrual of AFUDC. This is standard practice and fairly compensates investors for putting their capital at risk. Ratepayers have no risk, only the obligation to fairly pay for service and adequately compensate Gulf's investors.

Q. Mr. Chriss further opines that any inclusion of CWIP in rate base should result in a lower authorized ROE for Gulf. Do you agree?

A. No, I do not. As I just stated, there is no shifting of risk by including CWIP in rate base. To the contrary, accepting Mr. Chriss' recommendation would result in a denial of a return on invested capital and a tremendous shift in established regulatory policy that would upset settled expectations. This would place even greater risks on investors. Concomitantly, bondholders would demand higher interest rates and stockholders would demand a higher ROE. This is not in the customers' best interest.

RECONCILIATION OF RATE BASE AND CAPITAL STRUCTURE

Q. What is the Commission's policy regarding the reconciliation of rate base and capital structure?

A. The Commission's policy is to reconcile the amount of rate base investment with the amount and sources of capital in a utility's capital structure which are used to support the rate base investment. This results in a matching of sources and uses of capital as a basis to more accurately determine the costs of providing service and to calculate a utility's revenue requirement in a rate proceeding.

Q. How is the reconciliation accomplished?

A. It starts with the company's balance sheet taken from its books and records. The assets as shown on the balance sheet are jurisdictionalized and adjusted consistent with regulatory policy to result in the company's rate base. The company's equity, debt and other liabilities are then adjusted to equal the rate base. Absent extraordinary circumstances or special policy considerations, the adjustments are made on a pro rata basis over all sources of capital in the company's capital structure.

Q. Why is the allocation done on a pro rata basis?

A. There are three main reasons why it is done pro rata. First, it is generally understood in the financial community and specifically recognized within regulation that funds are fungible and cannot generally be traced from a specific source to a specific application. Second, making allocations to deferred taxes on any basis other than pro rata could have the effect of violating income tax normalization requirements and putting the deferred taxes in jeopardy. And third, pro rata is a fair and easily applied allocation methodology that is consistent with cost recovery in adjustment clauses.

Q. What does Federal Executive Agencies (FEA) Witness Gorman recommend in regard to the reconciliation of rate base and capital structure?

A. Mr. Gorman recommends that the Commission's pro rata allocation methodology be restricted only to investor sources of capital and not applied at all to deferred taxes and customer deposits. This has the effect of over-weighting these sources of capital and inappropriately reducing Gulf's overall weighted cost of capital.

Q. What is Mr. Gorman's rationale for making this recommendation?

A. Mr. Gorman opines that the customers have provided these sources of capital and should receive the full benefit of them.

Q. Do you agree with his opinion?

A. No, his opinion that customers have provided the deferred taxes is debatable. More importantly, his opinion that customers are not receiving the "full benefit" is misplaced.

Q. What gives rise to deferred taxes?

A. Deferred taxes are an accounting entry which recognizes the difference in time between when an amount of income tax expense is recognized on the books and when the liability arising from that expense becomes payable. The bulk of deferred taxes generally arise from differences in the amount of depreciation expense allowed as a deductible expense in the current period (accelerated depreciation) and the amount of depreciation expense actually booked as a current period expense. In this sense, the deferred taxes are an interest free loan from the government. The amount of income tax expense recognized as a recoverable expense in rates is the current period expense and reflects the current period cost of providing service. This is what customers pay. The government essentially allows a delay in the payment of the associated taxes.

Q. Do customers receive the full benefit of the deferred taxes?

A. Yes, they do in two ways. First, the impact of accelerated depreciation reverses over time and customers receive the full tax benefit of the depreciation over the life of the asset. Second, during the time that the deferred taxes exist on the company's books, the zero cost loan from the government is included in the company's capital structure at zero cost.

Q. Does Mr. Gorman's suggested reconciliation methodology result in customers receiving a full benefit of the cost savings?

A. There actually is no cost savings, just a delay in the recognition of the expense and when the associated liability comes due. The benefit of this delay, however, is fully recognized. In contrast, Mr. Gorman's approach would result in a "double counting" of benefit to customers.

Q. How so?

A. Deferred taxes and customer deposits are sources of capital that are used to support investments across all of Gulf's assets, just like equity and debt capital obtained from investors. When an asset is removed from or not allowed in rate base, Mr. Gorman's approach ignores this. Instead, he supports full recognition of the non-inclusion of the asset in rate base, but ignores the deferred taxes and customer deposits which support that asset. Under his approach, customers are not required to pay for the asset and are beneficiaries of 100% of the deferred taxes. In this sense, there is a "double counting" of benefit to customers.

Q. How did the Commission allocate rate base adjustments in the last Gulf rate case?

A. The Commission did it pro rata. In Order No. PSC-12-0179-FOF-EI for Gulf, the Commission stated:

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

Q. Has the Commission recently expressed a concern with double counting deferred income taxes?

A. Yes, in its Order No. PSC-10-0153-FOF-EI, addressing its decision in a recent FPL rate case, the Commission stated:

> We are concerned that the double counting of deferred income taxes might result in a violation of tax normalization rules. Per IRC§168(i)(9), tax normalization requires any ratemaking adjustment with respect to a utility's deferred income tax reserves to be consistently applied with respect to rate base, depreciation expense, and income tax expense. Pursuant to IRC§168(f)(2), the consequence of violating the

normalization method of accounting is the loss of the ability to claim accelerated depreciation for income tax purposes. Such a normalization violation would result in the loss of the ability to use accelerated tax methods of depreciation. Consistent with prior PSC orders, tax normalization rules, and as discussed in greater detail below, FPL has properly allocated pro-rata adjustments to all sources of capital.

The Commission went on to give three reasons why it was making all allocations on a pro rata basis, citing the need to be consistent with cost recovery clause treatment, concerns over potential normalization violations, and a lack of materiality. The Commission did direct Staff to conduct a generic review of its allocation policy.

Q. Did such a review take place?
A. Yes, there was a workshop conducted by Staff on May 12, 2010.

Q. Were there any changes made by the Commission to its allocation methodology as a result of this workshop?
A. No, not to my knowledge.

Q. You earlier answered that the Commission cited the need for consistency with the rate of return used for cost recovery clauses. Is Mr. Gorman's proposal consistent with the rate of return used for cost recovery clauses?
A. No, it is not. Mr. Gorman's proposal has the effect of assigning the lower

cost (or cost-free) sources of capital to investments that are recovered through base rates and assigning the higher cost investor-supplied sources of capital to clause-related investments that are removed from base rates and recovered through the clauses. If Mr. Gorman's proposal were to be adopted, consistency would require a higher rate of return for investments recovered through clauses. Of course, the most accurate and simplest solution is to maintain the Commission's policy of doing both base rates and clause recovery at the same rate of return based on a pro-rata reconciliation.

STORM DAMAGE ACCRUAL

Q. What is storm damage accrual?

A. It is the annual amount credited to the storm damage reserve. It has a corresponding debit entry to an expense account and is a cost of providing service. Therefore, it is included in a company's rates. It is based upon anticipated future storm-related expenditures and spreads storm-related costs evenly from year to year to minimize potential rate swings for customers.

Q. What is the storm damage reserve?

A. It is the net amount within Account No. 228.1 set aside to cover actual restoration costs from storms. The annual accrual adds to the reserve balance while actual storm-related expenditures reduce the reserve. The reserve acts to absorb the sometimes severe fluctuations in storm-related expenditures from year to year.

Q. Does the inclusion of a storm damage accrual in rates add to a utility's earnings?

A. No, it does not. It is an expense that is used exclusively to provide for future storm restoration costs. It does add to a company's cash flow. However, Gulf has a funded reserve and the cash is deposited into the funded reserve.

Q. Does the reserve provide any benefit to Gulf's customers in addition to covering storm restoration costs?

A. Yes, any delay between the receipt of the cash and the crediting to the funded reserve is treated as a reduction to rate base and reduces rates proportionately.

Q. Have Florida's utilities always used storm reserves to cover storm restoration costs?

A. Yes, the reserve has always been part of the accounting for storm costs. However, before Hurricane Andrew most of the annual costs were covered by commercially available insurance on transmission and distribution facilities. After Hurricane Andrew, such insurance was no longer cost effective and the Commission chose to implement a self-insurance plan by annual accruals to the reserve. In essence, the annual accrual took the place of insurance premiums that were previously included in rates as a cost of providing service.

Q. What is the amount of annual accrual that Gulf is requesting to be included in rates?

A. Gulf is seeking an annual accrual of $9.0 million based on a targeted reserve of $48 million to $55 million. Gulf's current accrual is $3.5 million which has been the Commission approved annual accrual since 1996. When the annual accrual for Gulf was set at $3.5 million, the targeted reserve was only $25 million to $36 million. Although the Commission did not change Gulf's annual accrual in its last rate case, the Commission set the current targeted reserve level of $48 million to $55 million.

Q. Is Gulf requesting an increase in its targeted reserve?

A. No.

Q. What do Mr. Garrett and FEA Witness Meyer recommend regarding Gulf's annual storm damage accrual?

A. Mr. Meyer recommends the existing annual storm damage accrual of $3.5 million be continued. Mr. Garrett recommends the accrual be discontinued. Mr. Garrett further recommends that the Commission revisit the reserve target range set in Gulf's last rate case.

Q. Do you agree with Mr. Garrett and Mr. Meyer's recommendations?

A. No, I do not. Mr. Garrett provides several reasons for his recommendation and I disagree with each reason he puts forth for his recommendation. I also disagree with Mr. Meyer's rationale for maintaining the current accrual amount.

Q. On what basis should the annual accrual be set?

A. The starting point should be the expected annual average storm loss coupled with an evaluation of the adequacy of the existing level of the reserve. The Commission should then make a determination whether the accrual should be set at the expected average annual storm loss, above it, or below it. If the Commission believes the current reserve is inadequate to protect customers from most storm events or a series of storm events, the annual accrual should be set an amount higher than the expected average annual loss. On the other hand, if the Commission believes the current reserve is more than adequate to protect customers from most storm events or a series of storm events, the annual accrual should be set at an amount lower than the expected average annual loss. Only if the Commission makes a determination that the existing reserve is either inadequate or more than adequate, should the annual accrual be set at an amount other than the expected average annual loss.

Q. Is this what Gulf is proposing?

A. Yes. Gulf is proposing an annual accrual of $9 million based on an expected average annual hurricane loss charged to the reserve of $6.8 million and an additional amount to increase the reserve. Based on the current annual accrual of $3.5 million, it is unlikely Gulf would ever reach the bottom of the target range. As Gulf Witness Erickson explains, the proposed accrual of $9.0 million would allow Gulf to potentially reach the bottom of the range in seven years.

Q. How should the expected average annual loss be determined?

A. It should be based on a statistically valid study that looks at both the expected frequency of all potential storm events and the expected dollar amount of storm losses to be incurred from each event.

Q. Does Mr. Garrett agree with this basis to determine the expected average annual loss?

A. No, he does not. He suggests that the expected average annual loss should be limited to what he calls "normal" storm losses based on the Company's actual loss experience.

Q. Do you agree with his approach?

A. No, I do not for two basic reasons. First, it is inconsistent with Commission policy and second, it is not logical to intentionally eliminate storm events that will eventually impact customers.

Q. How is the approach suggested by Mr. Garrett inconsistent with Commission policy?

A. Remember that the Commission's current use for the storm damage reserve is the result of the Commission's decision to implement a self-insurance approach to protect customers from storms. Prior to Hurricane

Andrew, the utilities and the Commission relied upon commercially available insurance to cover costs from all storm events, not just small storms. And the premiums for this insurance coverage were appropriately included in rates, with no distinction made between the amount of the premiums applicable to Category III and larger hurricanes and that applicable to smaller storms. Following Hurricane Andrew, Florida Power & Light (FPL) was required to submit a storm study to implement its self-insurance mechanism. FPL's study included a statistical analysis of the expected annual damage and included Category I through V storms. FPL calculated its average annual loss to be $20.3 million and further concluded that even if the accrual were set at the $20.3 million the resulting reserve would not cover losses from all potential catastrophic storms. FPL took a conservative approach and requested an initial annual accrual of only $7.1 million.

Q. What did the Commission ultimately decide?

A. The Commission found that FPL's study was sufficient to determine the expected average annual loss. However, in response to concerns expressed that an increase above the $7.1 million was needed to grow the reserve balance and to reduce dependence on special customer assessments (surcharges), the Commission accepted an agreement to increase the annual accrual to $10 million.

Q. So the Commission decided to set the annual accrual for FPL at an amount lower than the amount indicated in the study?

A. Yes, that is correct. The Commission used its discretion and the facts applicable to FPL at that time to set the average accrual at an amount lower than the study's indicated expected average annual loss. What is significant is the Commission's acceptance of the methodology that included all hurricanes (Categories I through V) and recognition that even doing so does not provide protection from all potential storm events or a series of storm events. Also significant is the Commission's decision to minimize dependence on surcharges to customers. In contrast, Mr. Garrett intentionally limits protection to only "normal" storms and advocates a dependency on customer surcharges.

Q. Do you agree with Mr. Garrett's approach?

A. No. I absolutely disagree with his approach and I believe it is illogical. It was never intended that the concept of a reserve and accrual to the reserve would ignore major storms. Rather the concept was to base the reserve and accrual on a study that took into account all storms and hurricanes. It was recognized that it would be impossible to guarantee the reserve would be sufficient to cover every extreme storm event or series of events and that a surcharge might be necessary. However it was never intended that the surcharge would be the sole mechanism for addressing major storms or a series of storms.

We know that higher intensity storms will eventually impact Gulf's territory. It would be illogical to ignore this reality and increase dependence on surcharges. Going back to the insurance analogy, their proposal would be like a homeowner insuring his or her house against small hurricanes, but not the larger ones. While the frequency of larger hurricanes is less, if and when one hits, customers would have a proportionately higher cost to pay at that time, a time when they could least afford it.

Q. Another of Mr. Garrett's arguments regarding discontinuance of the storm damage accrual is based on his belief that storm hardening efforts will reduce the expected storm damage. Based on this belief he opines that the current reserve balance is sufficient to cover normal storm activity and that the target range of reserve previously set by the Commission should be revisited. Do you agree with him?

A. No, I do not for several reasons. First, as I have previously noted, he is mistaken in his assertion that the reserve was intended to cover only "normal" storm activity. The methodology to determine the level of reserve to be targeted and the necessary accrual to reach that target include all storms.

With regard to the storm hardening program, there has been no experience upon which to base an assessment of how much storm damage cost savings might result. But more importantly, it is a one-sided adjustment that fails to recognize factors that would increase costs charged to the reserve. Since the time of the storm study, there have been additional investments in transmission and distribution (T&D) plant, and significantly more investment in transmission plant is proposed in the near future (Plant Crist and Plant Smith Transmission Costs). The cost data used in Gulf Witness Harris' 2009 storm study show an estimated replacement value of Gulf's T&D plant to be $2.2 billion as of 2009. Based on net additions and retirements in T&D from 2009 to 2013, the estimated replacement value increases to $2.7 billion in 2013. This does not even consider the test year increases and the significant increases in transmission subsequent to the test year. Additionally, there are other types of property losses that are charged to the accrual which are not a part of the storm study. These factors suggest the accrual and reserve are, in fact, conservative estimates of what is actually needed to cover storm damage losses.

Q. Mr. Garrett references Commission orders eliminating storm damage accruals for FPL, Duke Energy Florida and Tampa Electric. Please address those orders and whether they represent a change in the Commission policy regarding storm damage accruals.

A. The Commission's policy has not changed. The orders Mr. Garrett refers to in the FPL and Duke Energy Florida (formerly Progress Energy Florida) case never became final and effective. Those orders were replaced by orders approving comprehensive settlements, and the treatment of storm damage accruals for those companies was part of those comprehensive settlements. The settlements proposed by the parties in those dockets covered numerous cost recovery and rate issues and were contingent upon Commission approval of the settlements in their entirety. The provisions in the settlement agreements on storm damage accrual were one element to the agreements and approval of the agreements in their entirety did not, and does not, mean the Commission's policy has changed.

Likewise, in the Tampa Electric case, the suspension of the storm accrual was part of a comprehensive settlement that was contingent upon approval of the settlement in its entirety by the Commission, and did not and does not represent a change in the Commission's policy.

The most recent case in which the Commission made a final decision on the amount of a storm accrual and the level of the reserve was Gulf's case decided last year. The Commission continued its policy of allowing an accrual and set the target range for the reserve.

It is significant that in the FPL, Duke and Tampa Electric cases the settlement agreements also included parameters to ensure recovery of storm costs and the replenishment of the reserve. The agreements maintain the concept of a reserve and a means of replenishing it. Each agreement provides for the use of surcharges to replenish the reserve to the level as of the implementation date of the settlement if the reserve is depleted. Instead of a forward basis for maintaining the reserve, an accrual, the agreements provide for a subsequent surcharge – both of which adhere to the concept of the need for and the maintenance of a reserve for storm damage.

In contrast, Mr. Garrett's proposal contains no mechanism for reserve replenishment to address storm damage costs from a single large storm or series of smaller storms. And with his recommendation to cease any accrual whatsoever, the existing reserve will assuredly be depleted in the future. This would inappropriately and unnecessarily place customers at risk for significant storm damage surcharges.

Q. Are there any other concerns you have with the approach taken by Mr. Garrett?

A. Yes, there are. Mr. Garrett places too much reliance on recent history. Using only an average of recent history can lead to grossly understated or overstated estimates of expected average annual storm costs. This is not surprising, given the large fluctuations possible in year-to-year storms. Moreover, the $868,000 annual average storm charge calculated by Mr. Garrett reflects only non-hurricane years. So he basically ignores the type of anticipated costs on which the accrual and reserve have historically been based and should continue to be based in the future. It is true that the type costs reflected in Mr. Garrett's average storm charge are charged to the reserve. However, since they are non-hurricane costs, they are the type of costs that are not included in Mr. Harris' storm study. This further indicates that Mr. Harris' estimate of annual charges to the reserve is conservative and that Mr. Garrett's is woefully inadequate.

Q. Mr. Garrett argues that current accruals for future storms create intergenerational inequities. Do you agree?

A. No. To the contrary, it assures intergenerational equity. The storm reserve is an accounting technique that provides a uniform and systematic means of matching costs to revenue recovery so that such costs will not be concentrated in a particular year. When customers receive service they are not only receiving the electrons flowing through their meter, but also the reasonable expectation that their service will be restored as quickly and safely as possible should an interruption occur from a storm or other event. Since storms will occur and only their timing in uncertain, the cost of providing electric service should include an allowance for a level of restoration activity that approximates the expected annual storm costs. To a great extent, it is analogous to purchasing insurance coverage through a monthly premium. Even though a claim may not be filed, the premium is still a current cost of providing the service.

Q. In addition to smoothing out rate impacts and properly matching costs and revenues, what other benefit does an appropriate annual storm reserve accrual provide?

A. It provides assurances to customers and the investment community that sufficient resources will be available to quickly and safely restore service following a storm. Following a storm, when a utility is striving to obtain outside assistance and goods and services from vendors, securing eventual payment should not be an impediment to service restoration.

Q. Should the Commission rely exclusively on surcharges as a means to recover storm costs?

A. No, the Commission should not. It is not in the customer's interest to be overly dependent on surcharges. An appropriate annual storm reserve accrual will lessen the likelihood of any surcharge being imposed. And when one is absolutely necessary, an appropriate annual storm reserve accrual will lessen its amount and thus the burden imposed on customers. While an appropriate annual storm reserve accrual may slightly increase rates currently, it can and will provide greater benefits to customers when they need it the most.

Q. Mr. Garrett also asserts that storm accruals embedded in rates create additional profits for the company. Is this a legitimate criticism of the storm accrual and storm reserve method to provide for storm restoration?

A. No, it is not. First, it should be reiterated that the use of storm accruals to a storm reserve is not designed to provide any profits to the accruing utility. To the contrary, it is designed for the express purpose of fairly and systematically recognizing the cost of storm restorations so as to not unduly impact earnings in any one year. This is particularly true for Gulf which has a funded reserve wherein earnings on the funds are credited to the reserve to cover future storm restoration expenditures.

Q. Isn't it true that Mr. Garrett asserts that the "profits" result from additional revenues from increased sales?

A. Yes, this is his assertion, but it has no merit. First, the amount embedded in rates for storm accruals are no different than amounts embedded in rates for other expenses, such as depreciation or insurance expenses. Within the regulatory rate setting model, it is recognized that customer growth or other increased sales will result in increased revenues in future years. But it is also recognized that there will be increases in expenses to serve the additional customers or provide the additional services that result in increased revenues. Depending on the net amount which remains from increased revenues compared to increased costs, the result could be an increase in profit (accretion) or a decrease in profit (attrition). This is routine and is to be expected. Only if there is so much accretion to cause overearnings or so much attrition that it causes underearnings, is it a matter which needs corrective action through a change in rates.

Q. Could this be the result from storm accruals?

A. No, it is simply not material enough to have such an effect. First, it needs to be understood that increased revenues from increased sales are not certain. A review of Gulf's experience with its sales forecast from the last rate case is evidence of this fact. Second, there will be increases in Gulf's investment in transmission and distribution assets along with customer growth that will likely increase the amount of storm restoration costs incurred when a storm event occurs. So while revenues could be growing, the costs to repair storm damage would also be growing.

Q. Mr. Meyer agrees that the recent growth in the reserve level shows the $3.5 million is an appropriate level for the accrual based on accumulated storm costs from 2005-2012. Do you agree?

A. No, for the same reasons I disagreed with Mr. Garrett. Mr. Meyer is also arguing the expected annual loss be limited to "most years" (Mr. Garrett's "normal storm losses") based on actual loss experience. Mr. Meyer's methodology is inconsistent with the Commission methodology that includes all storm events. Mr. Meyer's methodology is not an appropriate prospective look at expected annual damage.

Q. Do you have any other comment regarding Mr. Meyer's testimony?

A. Yes. Mr. Meyer states Gulf can use the proceeds from insurance claims to offset its storm costs. Mr. Meyer apparently does not understand that the reserve was set up in recognition that adequate and cost effective insurance is not available for transmission and distribution assets.

STEP INCREASE

Q. What do OPC Witnesses Garrett and Norwood recommend in regard to Gulf's request for recovery of the Plant Crist and Plant Smith transmission costs through a step increase to base rates?

A. They recommend the step increase of $16.392 million be denied, and one of the bases for denial is the uncertainty of the increase for the upgrades "due to the fact the forecasts extend approximately 18 months beyond the end of the 2014 test year."

Q. Do you agree with that basis for the recommendation?

A. No. I do not agree for a number of policy and factual reasons. First, it should be emphasized that the projects included in the step increase will be in-service by July 1, 2015, only six months after the end of the 2014 test year in this proceeding. Second, I disagree as a matter of policy.

Q. Why do you disagree as a matter of policy?

A. The Commission has statutory and rule authority to consider incremental adjustments in rates during the period new rates are in effect and to set rates accordingly. A company seeking a step or subsequent year increase, or an affected party seeking a subsequent year decrease must show with reasonable certainty that there will be future changes sufficient to justify the subsequent year rate change. As such, the use of subsequent year adjustments is a valuable and useful regulatory tool that is necessary for the Commission to meet its statutory obligations to all parties.

Q. Why is the use of a subsequent year adjustment a valuable regulatory tool?

A. The use of a subsequent year adjustment can minimize or eliminate regulatory lag for a longer period of time, without the need for back-to-back rate cases.

Q. What is regulatory lag?

A. Regulatory lag is the period of time from when a change in rates (up or down) is needed and when the rate change can be legally implemented. It can have a significant impact on a utility's ability to earn its authorized return when capital expenditures and inflation are high. Regulatory lag is inherent in the regulatory process, and ways to minimize its impacts should be part of good regulatory policy. Subsequent year adjustments are an accepted and recognized method of addressing forecasted financial and operating conditions that affect a utility's opportunity to earn the approved rate of return.

Q. Has the Commission previously used subsequent year adjustments to set rates?
A. Yes, the Commission has done so and the use of subsequent year adjustments has become standard practice in Florida.

Q. Is the Commission's policy reflected in statute?
A. Yes, it is. Section 366.076(2), Florida Statutes, authorizes the Commission to adopt rules that provide for "adjustments of rates based on revenues and costs during the period new rates are to be in effect and for incremental adjustments in rates for subsequent periods." The Commission adopted Rule 25-6.0425, to implement this statutory provision.

Q. Has the use of subsequent year adjustments been a recent development in Florida?
A. No, subsequent year adjustments have been used at least as far back as 1984. In a case involving FPL (Docket No. 830465-EI, Order No. 13537), the Commission not only determined that it had the legal authority to consider a subsequent year adjustment, the Commission determined that a 1985 "subsequent year" was appropriate to use to set rates.

This determination was appealed to the Florida Supreme Court in *Floridians United for Safe Energy, Inc. v. Public Service Commission*, 475. So. 2d 241 (Fla. 1985). In its decision approving the use of the subsequent year, the Court explained:

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

The Commission has an obligation to scrutinize the subsequent year request and approve a subsequent year rate change, if it is justified based on the information provided by the Company.

Q. In response to a previous question, you responded that there are also factual reasons for why you disagree with the recommendation to deny the requested step increase. What are your factual reasons?

A. Mr. Garrett and Mr. Norwood assert that because the forecasts extend beyond the test year and are too uncertain, the step increase should be denied. I disagree with these assertions and discuss their policy implications.

First, it is a given that rates are set prospectively and to best establish future rates you must consider future costs and future revenues (if applicable). Gulf has provided information showing the need for the transmission upgrades, the cost of those upgrades, and the time the upgrades will come into service. These are known and measurable costs that should be addressed by the requested step increase. Given that the upgrades are for environmental compliance and not for the purpose of creating additional sales, it is not necessary to project incremental revenues for the proposed step increase.

Second, as stated above, regulatory lag can affect a utility's ability to earn its authorized return and can have the effect of denying a regulated company a reasonable opportunity to actually achieve its authorized return. This point is substantiated by Gulf Witness Ritenour's testimony that the first year revenue requirements for the transmission upgrades will be $17 million, which would have a significant impact on Gulf's earnings in 2015, necessitating a costly limited or full rate proceeding soon after this case is completed.

Q. You've stated Gulf could initiate another rate proceeding to recover the transmission costs. Would this be a better approach since it will be closer in time to when the project goes in service and the need for a rate increase will be better known?

A. No, it would not. Consistent with Commission policy, the current rate case is an appropriate vehicle to recognize these costs. Ignoring the costs now and requiring Gulf to seek recovery by other means would only add an element of increased risk and additional regulatory costs. This would not be in the customers' best interest.

Q. Are there recent examples of the Commission authorizing a step increase similar to what Gulf is requesting?

A. Yes. Most recently, the Commission approved a step increase for Gulf Power in its last rate case. The step increase that was approved in that case went into effect the following year and was related to turbine upgrades that did not go into service until late in the test year. Also, the Commission approved a step increase for Tampa Electric Company (TECO), in Docket No. 080317-EI, In re: Petition for Rate Increase by Tampa Electric Company. In that case, TECO was seeking cost recovery of five separate combustion turbine units, two to be completed in May 2009 and three to be completed in September 2009. TECO sought recovery by fully annualizing the costs of the combustion turbine units in its 2009 test year.

Q. What did the Commission decide for the costs of the five combustion turbine units?

A. The Commission rejected TECO's full annualization of the units, but allowed cost recovery through a subsequent increase in rates. The Commission determined that the costs of the five combustion turbine units should be recovered as part of the rate case and not put off into a subsequent limited proceeding. The Commission further acknowledged that denying cost recovery of the full costs of the five units could deny TECO a reasonable opportunity to actually achieve its authorized return in 2010. In its non-final Order No. PSC-09-0283-FOF-EI, the Commission stated at page 6:

> Under normal circumstances, the Company's pro forma adjustments for the five simple cycle combustion turbine units

would have been eliminated from the test year results because we believe it violates the principle of matching revenue, expenses, and rate base for the projected test year. We do not want consumers paying for items that are not in commercial service during the test year. However, the five simple cycle combustion turbine units represent a significant expenditure for the Company if placed into service in the 2009 test period. Thus, as stated, TECO may experience a significant adverse impact on earnings in 2010, and would most likely lead to it petitioning the Commission for a limited proceeding within a very short period of time after our decision herein.

To avoid a significant cost to consumers and significant length of time to conduct a limited proceeding, we have decided to grant TECO a step increase in rates, effective January 1, 2010, for the cost of the five CT units...

Q. You stated that the Commission's Order was non-final. Why did the Order not become final?

A. The intervenors in the TECO case filed a motion for reconsideration of the Commission's decision. The intervenors alleged that they were denied due process since the step increase was not part of TECO's original request. The intervenors further alleged that the step increase violated various statutes and rules and would result in a mismatch of sales and revenues. The Commission denied all aspects of the intervenors' motion for reconsideration and the intervenors subsequently appealed the Commission's decision. The parties then resolved the appeal through a Commission-approved settlement and the Order did not become final.

Q. Aren't the facts of the TECO case different from this request for a step increase? In TECO the expenditures were within the test year, correct?

A. The facts are slightly different, but that does not call for a different result in this case. The TECO case stands for the principle that known and measurable changes, such as increased investments made during the time rates are projected to be in effect, should be reflected in rates such that rates will be designed to recover costs on a going-forward basis. Absent such recognition, a utility could be denied a reasonable opportunity to actually achieve its authorized return. The TECO case further stands for the proposition that limited scope proceedings should not be pursued when the relevant costs can be reasonably included within a full revenue requirements rate case.

Q. Should the Commission deny the step increase being requested by Gulf in this proceeding?

A. No. The Commission should give the proposed step increase due consideration as a matter of precedent and policy.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit

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- Office of the Public Counsel, Chief Regulatory Analyst, 1987 – 1991
- Florida Public Service Commission, Executive Assistant to the Commissioner, 1981 – 1987
- Office of the Public Counsel, Legislative Analyst II and III, 1979 - 1981
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- Office of the Public Counsel, Legislative Analyst I, 1977 – 1978
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- Nuclear Waste Strategy Coalition, 2000 - 2006, *Board Member*
- Federal Energy Regulatory Commission (FERC) South Joint Board on Security Constrained Economic Dispatch, 2005 - 2006, *Member*
- Southeastern Association of Regulatory Utility Commissioners, 1991 - 2006, *Member*
- Florida Energy 20/20 Study Commission, 2000 - 2001, *Member*
- FCC Federal/State Joint Conference on Accounting, 2003 - 2005, *Member*
- Joint NARUC/Department of Energy Study Commission on Tax and Rate Treatment of Renewable Energy Projects, 1993, *Member*
- Bonbright Utilities Center at the University of Georgia, 2001, *Bonbright Distinguished Service Award Recipient*
- Eastern NARUC Utility Rate School - Faculty Member

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

STEVEN M. FETTER

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Steven M. Fetter
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Steven Fetter. My business address is 1240 West Sims Way #50, Port Townsend, Washington 98368.

Q. On whose behalf are you providing rebuttal testimony?

A. I am testifying on behalf of Gulf Power Company (Gulf or the Company).

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring Exhibit SMF-1 consisting of two schedules. The information contained in these schedules is true and correct to the best of my knowledge.

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

A. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission (Michigan PSC).

Q. What is your educational background?

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. Please describe your service on the Michigan Public Service Commission.

A. I was appointed as a Commissioner to the three-member Michigan PSC in October 1987 by Democratic Governor James Blanchard. In January 1991, I was promoted to Chairman by incoming Republican Governor John Engler, who reappointed me in July 1993. During my tenure as Chairman, timeliness of commission processes was a major focus and my colleagues and I achieved the goal of eliminating the agency's case backlog for the first time in 23 years. While on the Michigan PSC, I also served as Chairman of the Board of the National Regulatory Research Institute, the research arm of the National Association of Regulatory Utility Commissioners.

Q. Please describe your role as President of Regulation UnFettered.

A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

Q. What was your role in your employment by Fitch?

A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory and legislative developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. In April 2002, I left Fitch to start Regulation UnFettered.

Q. How long were you employed by Fitch?

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months shortly after I left the firm.

Q. How does your experience relate to your testimony in this proceeding?

A. My experience as a Commissioner on the Michigan PSC and my subsequent professional experience with financial analysis and ratings of the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role in setting rates and also in determining appropriate terms and conditions of service for regulated utilities. These are among the factors that enter into the process of utility credit analysis and formulation of individual company credit ratings. It is undeniable that a utility's credit ratings significantly affect the ability of a utility to raise capital on a timely basis and upon reasonable terms.

Q. Have you previously given testimony before regulatory and legislative bodies?

A. Since 1990, I have testified on numerous occasions before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, federal district and bankruptcy courts, and various state legislative, judicial and regulatory bodies on the subjects of credit risk and cost of capital within the utility sector, electric and natural gas utility restructuring, fuel and other energy cost adjustment mechanisms, construction work in progress and other interim rate recovery structures, utility securitization bonds and nuclear energy. I have previously testified and been accepted as an expert witness before the Florida Public Service Commission (FPSC or the Commission) in Docket No. 060635-EU relating to the Taylor Energy Center and in Docket No. 060658–EI on behalf of Progress Energy Florida, Inc.

My full educational and professional background is presented in my Exhibit SMF-1, Schedule 1.

Q. What is the purpose of your rebuttal testimony?

A. Utilizing my past experience as a state utility commission chairman and head of a major utility credit rating practice, my testimony rebuts positions taken by Federal Executive Agencies (FEA) Witness Gorman related to financial integrity and credit ratings, capital structure and return on equity, and Office of Public Counsel (OPC) Witness Woolridge related to return on equity.

Specifically, I respond to Mr. Gorman's claim that a return on equity of only 9.45 percent would be supportive of Gulf's financial integrity and credit standing, and his incorrect conclusion that the total debt ratio he recommends would support Gulf's current bond rating. I also respond to Dr. Woolridge's recommendation that Gulf's authorized return on equity be set at 9.0 percent.

In order to rebut these statements, I will focus on the importance of credit ratings for regulated utilities and their customers; the importance of constructive utility regulation as an underpinning of strong credit quality; how the Company is currently viewed by the credit rating agencies; and how the financial community currently views the utility regulatory environment within Florida – information which will indicate the fallacy of Mr. Gorman's and Dr. Woolridge's conclusions.

Q. Please summarize the conclusions of your rebuttal testimony.

A. A utility's credit ratings are central to its ability to raise capital at reasonable cost and upon reasonable terms. Regulation is a key qualitative component of a utility's credit ratings. Florida, having recovered from a negative regulatory reputational blip in 2010, is once again viewed by the market as among the most credit supportive states. This is a strong positive factor in the credit ratings assigned to the state's regulated utilities.

Gulf Witness Vander Weide, the Company's Return on Equity (ROE) witness, explains in detail the appropriate ROE level and capital structure for Gulf under its current circumstances – both of which are at odds with Mr.

Gorman's and Dr. Woolridge's positions. I supplement Dr. Vander Weide's recommendations by illustrating that Mr. Gorman's and Dr. Woolridge's ROE recommendations are far outside the mainstream of regulatory decision-making over the past five years, and that Mr. Gorman has misapplied the Standard & Poor's ("S&P") utility guidelines risk matrix. All of this information shows that positive regulatory support is needed to maintain Gulf's "A" category credit ratings, as opposed to Mr. Gorman's assertion that his proposed total debt ratio would be sufficient because it would "support an investment grade bond rating." I will discuss below that "investment-grade" status is not enough – since it covers ratings in the lowest investment-grade rating category of "BBB" and above, and why it is important for Gulf to be able to maintain its current "A" category credit ratings.

In sum, a constructive decision in this case should avoid any weakening in the Company's credit profile. Conversely, in view of the unexpected negative rate case decisions by the FPSC in 2010, which shook the confidence of the financial community, a less than constructive decision here could lead to negative credit rating actions, which would: 1) increase the Company's cost of capital during a time of substantial capital investment; 2) create the potential that access to capital markets during periods of economic stress could be restricted; and 3) ultimately result in higher rates for customers.

II. CREDIT RATINGS AND THEIR IMPORTANCE TO REGULATED UTILITIES

Q. Mr. Gorman testifies that the rating agencies would find his ROE and capital structure recommendations to be consistent with Gulf's current credit ratings, and Dr. Woolridge claims that his 9.0 percent ROE recommendation is appropriate for Gulf. Do you agree with those assessments?

A. No I do not, and I think if I were to provide some background about credit ratings, it would be easier to see the inadequacy of Mr. Gorman's and Dr. Woolridge's recommendations on both a quantitative and qualitative basis.

Q. Please explain.

A. A credit rating reflects an independent judgment of the general creditworthiness of an obligor or of a specific debt instrument. While credit ratings are important for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company. Credit rating determinations are made by credit rating agencies through a committee process involving individuals with knowledge of a company, its industry and its regulatory environment. Corporate rating designations of S&P and Fitch have 'AA', 'A' and 'BBB' category ratings within the investment-grade ratings sphere, with 'BBB-' as the lowest investment-grade rating and 'BB+' as the highest non-investment-grade rating. Comparable rating designations of Moody's at the investment-grade dividing line are 'Baa3' and 'Ba1', respectively.

Corporate credit rating analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties to gauge both the short-term and longer-term financial health and viability of a company, including decisions related to required collateral levels, with higher-rated entities facing lower requirements.

Q. What credit ratings does Gulf now hold?

A. Gulf holds a corporate rating of 'A' with a Negative outlook from S&P; an 'A3' (Stable outlook) issuer rating from Moody's; and an 'A-' issuer rating from Fitch with a Stable outlook. The ratings from Moody's and Fitch are at the lowest level of the "A" category, one notch above the "BBB" category.

Q. Why are credit ratings important for regulated utilities and their customers?

A. A utility's credit ratings have a significant impact on its ability to raise capital on a timely basis and upon reasonable terms. As respected economist Charles F. Phillips states in his oft-cited treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) <u>they determine, in part,</u>

the cost of new debt, since both the interest charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[1]

Thus, a utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates, but it is also able to share the benefit from those attractive interest rate levels with customers since cost of capital gets factored into utility rates. Conversely, the lower a utility's credit rating, the more the utility must pay to raise funds from debt investors to carry out its capital-intensive operations, and those higher capital costs get factored into the rates that consumers are required to pay.

A strong credit profile is especially important for a regulated utility like Gulf, whose forecasted capital investment is slated for significant increases over the near term, along with the likelihood of costly future environmental expenditures related to its generation being predominately coal-fired – all coming amidst a regional economy that still shows signs of weakness from the financial crisis of several years ago.

As all parties to this proceeding know, a regulated utility must maintain safe and reliable service under all economic conditions, and thus is required to

[1] Phillips, Charles F., Jr., The Regulation of Public Utilities, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250 (emphasis supplied). See also Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at pp. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

raise funds even during periods when the markets are in turmoil with costs escalating wildly. Accordingly I believe that a regulated utility that has achieved "A" category credit rating status should be assured of having access to the capital markets upon reasonable terms, even when the financial markets are operating within a stressed environment. (See, for example, "The A Rating," by Steven M. Fetter, Electric Perspectives, Edison Electric Institute, May/June 2009 (attached as Exhibit SMF-1, Schedule 2.) Thus, if the Company is able to maintain its current 'A' category credit ratings, such status should accrue to the benefit of all stakeholders, most especially Gulf's customers. Conversely, movement of one or more of the Company's ratings into the 'BBB' category would increase financing costs and potentially jeopardize full and easy access to the capital markets should a global financial crisis reoccur.

Q. What qualitative factors are used by the rating agencies to establish credit ratings?

A. The most important qualitative factors are regulation, management and business strategy, and access to energy, gas and fuel supply with recovery of associated costs.

Q. What are the key quantitative measures?

A. The major rating agencies use several financial measures within their utility financial analysis. S&P currently highlights the following three ratios as its key indicators: Funds from Operations to Debt (FFO/Debt), Debt to

Earnings Before Interest, Taxes, Depreciation and Amortization (Debt/EBITDA), and Debt to Capital (Debt/Capital).[2]

Q. Why is regulation a key qualitative component of the credit rating process?

A. Regulation is a key factor in assessing the financial strength of a utility because a state public utility commission determines revenue levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery and return on investment) and the terms and conditions of service that affect a utility's cost of service. As Moody's has noted, "A utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings."[3]

The quality and direction of regulation play a key role in shaping investors' expectations of how these factors may change in the future. Qualitative assessment of the regulatory environment affects utility investors' decisions because, before they are willing to put forward substantial sums of money, they must assess the degree to which regulators understand the economic requirements and the financial and operational risks of a rapidly changing industry. Utility investors understand and accept the role of pervasive regulation, but they seek from the regulatory process decision-making that is fair, with a significant degree of predictability.

[2] S&P Research: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," September 18, 2012.

[3] Moody's Research: "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality: Evaluating a Utility's Ability to Recover Costs and Earn Returns," June 18, 2010.

For these reasons, rating agencies look for the consistent application of sound economic and regulatory principles by utility regulators. If a regulatory body were to encourage a utility to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory principles in a manner consistent with those expectations, investor interest in providing funds to the utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

Q. Have the recent financial and operational challenges facing all utility managements increased the financial community's focus on the actions of utility regulators?

A. Yes, without a doubt. The turmoil in the financial markets that erupted almost six years ago tested the financial standing of the utility sector like never before. Liquidity, or access to cash when needed, has always been a major issue for regulated utilities, but it has leaped to the forefront of utility financial and operational concerns and has driven structural decisions on the part of utility executives. As the Wall Street Journal reported at the beginning of the financial crisis, "Disruptions in credit markets are jolting the capital-hungry utility sector, forcing companies to delay new borrowing or to come up with different – and often more costly – ways of raising cash."[4] Credit spreads for "BBB"-rated debt issuers are significantly higher than for "A"-rated issuers, over the long term, and particularly when credit markets are in distress -- indeed, some 'BBB' category companies were shut out of

[4] "Utilities' Plans Hit by Credit Markets," Wall Street Journal, October 1, 2008.

the short-term commercial paper market for a period following the Fall 2008 financial crash.

While the financial markets have stabilized to a degree, the severe and unanticipated nature of the global financial crisis illustrated well that "BBB" category utilities are much more vulnerable than "A" category utilities when capital markets are in a state of upheaval. With negative economic effects still lingering, in part related to both the still-pending US federal government budgetary and debt ceiling challenges and serious European sovereign debt concerns, utility managements must stay vigilant in maintaining operational efficiency and financial stability against the potential threats of diminished investor interest and higher costs to serve ratepayers.

Thus, while "Regulation" has always garnered the attention of the financial community, years ago it seemed to be a focus only during the days leading up to a regulator's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and assess regulatory, legislative and political factors that could affect a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but also the manner in which they considered restructuring of the entire utility industry. And of course the stresses within the credit markets during the global financial crisis I referred to earlier, with their huge financial repercussions, have increased the stakes substantially beyond regulators merely having to adjust their policies to deal with flawed restructuring initiatives.

Q. Do the rating agencies agree that utility regulators and their decision-making are important within the credit rating process?

A. Yes, as I saw firsthand when Fitch recruited me to provide regulatory analysis after I had decided to move on from the Michigan PSC. S&P highlighted the critical role that regulators play in a November 26, 2008 report entitled "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry":

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment.

Fitch also cites the importance of regulation in explaining its COR (comparative operating risk) methodology for utilities, stating in its May 16, 2011 update to COR in "Rating North American Utilities":

> A historically supportive state regulatory and legislative environment and lack of controversial future regulatory events help support a COR of 1 or 2 {the lowest risk in

> Fitch's scale of 1 to 5} for utilities with sound operating records.

Moody's Investor Service also cites the importance of regulation to credit quality, noting in their June 18, 2010 note "Regulatory Frameworks – Ratings and Credit Quality for Investor Owned Utilities":

> When evaluating the credit quality of a utility, the degree of support it may depend upon from its regulators is typically one of Moody's most significant considerations.

III. FINANCIAL COMMUNITY PERCEPTIONS OF THE FPSC

Q. Within this increasingly stressed financial environment, how is the FPSC viewed by the financial community?

A. Very positively. Probably the most objective and respected commentator on regulatory policy and activities from a financial community perspective is Regulatory Research Associates (RRA). RRA currently rates the Florida regulatory environment (which goes beyond the Commission to also include legislative and executive branch policies) as Above Average 3, among the top eight regulatory jurisdictions upon which RRA currently opines. Such positive status is a very strong factor within the context of credit rating analysis. I caution, though: it was only three years ago that RRA warned investors that the FPSC's actions were "negative" and "highly politicized" and downgraded its commission rating, reinforcing a perception that was not beneficial to either Gulf's customers or investors.

Q. Does Moody's share the current favorable assessment?

A. Yes, Moody's recently highlighted the "[i]mproved political and regulatory environment and strong cost recovery provisions" existing under the current membership of the FPSC, as opposed to prior "highly politicized" decisions in 2010. Moody's further noted that, in view of the "reasonably credit supportive" decision in the Company's 2012 rate case, it expects a similarly credit supportive outcome in this proceeding. Indeed, the agency noted that "[a]lthough Gulf's cash flow coverage metrics are below the parameters typically required for an A3 rating after adjusting for bonus depreciation, this is largely offset by an above average regulatory framework..." Moody's statement about weakness in the Company's financial profile conflicts with Mr. Gorman's claim that his significantly lower ROE recommendation would support Gulf's current "A3" rating from Moody's.[5]

Q. And S&P's view?

A. Also positive. In its March 21, 2013 report on Gulf, S&P stated that:

> The regulatory environment for Gulf Power is generally constructive and supportive of credit quality, allowing the company to recover invested capital on a timely basis while

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[5] Moody's Research: "Gulf Power Company," August 9, 2013.

earning an adequate return on equity (ROE), and to recover capacity and fuel costs through riders.[6]

Q. And Fitch's assessment?

A. Similarly positive, but with concern about the recent history at the Commission. In a February 1, 2013 report, Fitch indicated that:

> The regulatory environment in Florida used to be one of the most constructive in the country, but a weak economy and political interference turned it into a very difficult one over 2009-2010. ...The Florida regulatory environment has much improved since and Gulf Power succeeded in getting a constructive outcome in its last rate case."[7]

Fitch cautioned, however, that "[u]nfavorable changes in current Florida regulatory policies ... would adversely affect Gulf Power's ratings."

Q. You described earlier three key quantitative measures used by the rating agencies. Can you discuss how S&P frames the qualitative and quantitative factors into a matrix to assist analysts and investors?

A. Yes. Building upon the three indicative ratios I mentioned above, S&P has explained how it views the interplay between quantitative and qualitative factors. As part of its utility credit rating process, S&P arrives at a "Business

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[6] S&P Research: "Gulf Power Co.," March 21, 2013.

[7] Fitch Research: "Gulf Power Company," February 1, 2013.

Risk Profile" designation that it considers in concert with its "Financial Risk Profile." Financial Risk is assessed based upon indicative ratios for the three key credit measures described above; the weaker the Business Risk Profile designation, the stronger the financial ratios must be in order to support an investment-grade rating.[8]

Q. What does S&P's Business Risk Profile designation reflect?

A. The Business Risk Profile designation reflects S&P's assessment of qualitative factors such as country risk, industry risk, competitive position, and profitability / peer group comparisons. In the past, S&P explained that assessment of regulation, markets, operations, competitiveness, and management enters into the determination of a Business Risk designation.[9] Under the S&P Methodology, Business Risk Profiles are ranked as 'Excellent', 'Strong', 'Satisfactory', 'Fair', 'Weak', or 'Vulnerable'. Similarly, under S&P's current framework, the Financial Risk designation captures risks related to accounting, financial governance and policies / risk tolerance, cash flow adequacy, capital structure / asset protection, and liquidity / short-term factors. Financial Risk Profiles are designated as 'Minimal', 'Modest', 'Intermediate', 'Significant', 'Aggressive', or 'Highly Leveraged', words that are used more for ranking than they are accurate descriptions of the strategies adopted by regulated utilities or the actions taken by their regulators.

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[8] S&P Research: "Methodology: Business Risk / Financial Risk Matrix Expanded," September 18, 2012.

[9] S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	**Financial Risk Profile**					
	Minimal	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

Gulf has been assigned an S&P Business Risk Profile of 'Excellent', and a Financial Risk Profile of 'Significant'.[10] As shown in S&P's Table 1 printed above, Gulf's risk profile normally would equate to a credit rating of "A-". Because S&P does not assign ratings solely on this matrix, but uses it as a guide, most outcomes will fall within a range of one notch on either side of the indicated rating. Gulf's current corporate credit rating of "A" stands one notch above the "Excellent" / "Significant" indication, and thus the Company's risk profile can accurately be described as showing a degree of weakness for its existing rating. As I discussed earlier, Moody's has also

[10] S&P Research: "U.S. Regulated Electric, Gas, and Water Utilities; Strongest to Weakest," July 30, 2013.

stated that its ratings methodology indicates that the Company's cash flow coverage metrics are weak for its "A3" credit rating.

Accordingly, in view of these indications of the potential for downward rating movement from both S&P and Moody's, I encourage the Commission to continue the positive trend in its regulatory policies and procedures to solidify the Company's current credit ratings. Downgrades, if they were to occur now, amidst the Company's forecasted substantial capital investment, would be very injurious financially to both customers and investors.

Q. You indicated earlier a difference of opinion with regard to Mr. Gorman's interpretation of the S&P risk matrix ranges. Can you explain?

A. Yes. As testified to by Gulf Witness Teel in his direct testimony (at p. 23), the Company's proposed capital structure targets 45 percent equity and 55 percent debt and preference or preferred stock. Mr. Teel notes that, after regulatory adjustments, this target capital structure results in a test year equity ratio of approximately 47.5 percent for ratemaking purposes. As can be seen in Table 2 below, S&P's range for debt to capital for a utility with Gulf's Financial Risk profile of "Significant" is 45-50 percent including debt the agency imputes from off balance sheet obligations (with equity in the range of 50-55 percent). S&P also treats preferred or preference stock as 50 percent debt and 50 percent equity, so debt ratios need to be adjusted for this factor as well. Before considering the impact of its off balance sheet obligations, the Company's debt ratio is classified as 50 percent or 52.5 percent. These ratios fall in the S&P "Aggressive" financial risk guideline range, thus consistent with the description of the Company's "A" rating as weak, as I discussed earlier. What this says to me is that, if the Company is seeking to maintain its current credit rating levels, if anything, a capital structure with a higher equity and lower debt level would be more fitting within this rate case, albeit at a slightly higher cost to customers.

Even if one were to accept Mr. Gorman's erroneous calculation of an S&P adjusted debt level of 47 percent, for argument's sake only, that level falls squarely within S&P's guideline range for Gulf with its "Significant" Financial Risk designation. The Commission should not allow itself to be confused by Mr. Gorman taking his debt number, comparing it to S&P's debt range for a utility with an "Aggressive" designation – which spans 50-60 percent debt – and then stating that his 47 percent debt calculation is much stronger than the S&P guideline. Rather, the appropriate S&P debt range for the Commission to focus on is the one for utilities designated "Significant", which clearly shows that the Company is not stronger than the guideline for its rating, and is not loading up with excess equity at the expense of its customers.

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

Q. Does Mr. Gorman take account of qualitative factors in his assertion that Gulf's credit quality would be fine if his ROE recommendation were to be adopted?

A. No he does not. While I disagree that Mr. Gorman's ROE recommendation would support Gulf's current credit ratings, even if it were to do so on a quantitative basis, there is no guarantee that the type of qualitative assessment that weakened the credit profiles of Florida's regulated utilities after the 2010 rate case decisions would not recur. As I discussed earlier, all three rating agencies place a significant weight on qualitative factors -- often described as approximating 50 percent, including most especially regulatory environment. These are the factors that can easily sway an agency's rating determination, especially for a utility possessing a borderline credit profile as Gulf appears to have. The best defense against such rating deterioration would be issuance by this Commission of a decision that is consistent with well-regarded regulatory policymaking across US jurisdictions. As I have shown earlier, the Company's capital structure proposals are, if anything, indicative of higher financial risk as compared to its peers, and as such, are supportive of Dr. Vander Weide's ROE recommendation. Conversely, I will show below that Mr. Gorman's and Dr. Woolridge's ROE recommendations bear no resemblance to ROE authorizations approved across the US during the recent past. Indeed, the fact that Mr. Gorman at no point even mentions the impact that his recommendations might have on the Company's qualitative factors illustrates to me that he does not fully appreciate the entire process by which the rating agencies arrive at their final credit rating judgments.

Q. Would you also discuss your disagreement with Mr. Gorman's and Dr. Woolridge's ROE recommendations?

A. Yes. While I defer to Dr. Vander Weide to analyze and discuss any flaws he might see in Mr. Gorman's or Dr. Woolridge's analyses, what troubles me is how weak their 9.0 percent and 9.45 percent figures are when compared to ROEs authorized by US regulatory commissions for electric utilities over the past five years. My review of RRA rate case data indicates that the lowest ROE authorization for US regulated electric utilities since the beginning of 2009 were set at 8.75 percent by the Connecticut Public Utilities Regulatory Authority for United Illuminating Company (UIL) on

February 4, 2009, and 9.0 percent by the Hawaii Public Utilities Commission for Maui Electric Company (MECO) on May 31, 2013. I note that UIL's 8.75 percent result appears to be the lowest ROE authorization since RRA began to compile such data. Since January 2009 (through October 24, 2013), there have been 232 reported ROE authorizations for US electric utilities. Of those, only the UIL and MECO decisions were at or below Dr. Woolridge's 9.0 percent recommendation, and only twelve (including the UIL and MECO decisions) were set below Mr. Gorman's 9.45 percent recommendation. In this compilation, with Dr. Woolridge's recommendation falling in the bottom 0.9 percent of all recent ROE authorizations and Mr. Gorman's recommendation falling in the bottom 5.2 percent, it is very hard for them to argue that adoption of either of their numbers would represent a constructive action by the Commission for Gulf. Indeed, based upon my past experience as a state utility regulator and bond rater, it is clear to me that an ROE authorized at either of those low levels would fail the "constructive" test on both quantitative and qualitative grounds.

Q. Finally, how do you view Gulf within the context of the S&P matrix?

A. I would expect that a constructive decision in this proceeding that shows sustained regulatory support for the Company through its growing investment cycle would allow Gulf to maintain an S&P Business Risk Profile of 'Excellent' and a Financial Risk Profile of 'Significant'. In that case, I expect that Gulf Power should be able to maintain its current "A" corporate credit rating, within one notch of the indication provided by the risk matrix.

I note, however, that a less than constructive regulatory decision here – such as one adopting either of Mr. Gorman's or Dr. Woolridge's inadequate ROE recommendations, following upon the problems at the FPSC in 2010, could undo the reputational progress that the Commission has achieved since that time. Such a decision would undermine the current positive view of Florida regulation, to the detriment of Gulf's customers, management, and investors.

Q. Do all rating agencies use the same methodology as S&P in analyzing Gulf's credit rating?

A. No. S&P utilizes a consolidated methodology that aims to combine parent and subsidiary credit profiles, risks, and potential support to assign a rating representing the weakest link, so to speak, once the support that likely would come from the parent or other affiliated entities is factored into the potential for default. Moody's and Fitch, on the other hand, initially focus on the individual entity being rated, and then depending upon the potential for significant external risk or support from affiliated companies, they may or may not modify their rating to reflect the risk or support factors from related entities. Interestingly, with Gulf holding a higher rating from S&P than from Moody's and Fitch, it would appear that the Company's ratings are benefitting from its connection to parent Southern Company and its subsidiaries.

Q. Since Moody's and Fitch do not use a consolidated methodology, might Gulf be at greater risk of a downgrade by these agencies if qualitative factors were to decline?

A. Yes. Under the Moody's and Fitch processes, Gulf on a standalone basis could more easily suffer a downgrade if a less than constructive decision were to be issued in this case. Moreover, with their ratings at the lowest "A" category level, a downgrade from either or both of them would be more financially injurious to the Company and its customers and investors than would a downgrade from the straight "A"-rated S&P.

Q. Does this complete your rebuttal testimony?

A. Yes it does.

Exhibit

STEVEN M. FETTER

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Education University of Michigan Law School, J.D. 1979
[Bar Memberships: U.S. Supreme Court, New York, Michigan]
University of Michigan, A.B. Media (Communications) 1974

April 2002 – Present
President - REGULATION UnFETTERED- Port Townsend, Washington

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors, including public utility commissions and consumer advocates; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; skills training in ethics, negotiation, and management efficiency.

Service on Boards of Directors of: Central Hudson (Fortis Inc. subsidiary) (Chairman, Governance and Human Resources Committee); and Previously CH Energy Group (Chairman, Governance and Nominating Committee; Member, Audit Committee; Lead Independent Director; and Chairman, Audit Committee and Compensation Committee), National Regulatory Research Institute, Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group; Participant, Keystone Center Dialogues on RTOs and on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director - Global Power Group, Fitch IBCA Duff & Phelps - New York / Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance; Member, Fitch Utility Securitization Team.

Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant - NYNEX - New York, Ameritech - Chicago, Weatherwise USA - Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner - Michigan Public Service Commission - Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987

Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary - U.S. Department of Labor - Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel - Michigan Senate - Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel - Michigan Governor William Milliken - Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney - National Labor Relations Board - Washington DC

Other Significant Speeches and Publications

The "A" Rating (Edison Electric Institute Perspectives, May/June 2009)

Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)

Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)

Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)

The Feds Can Lead...By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)

Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)

Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

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securities—the riskier the debt, the more expensive the financing. Regarding equities, declining stock prices and rising bond yields convey the same message. The impact on debt and equity financing from mounting risk compounds the difficulty and expense to gain access to the public markets.

Because the ratemaking process is intended to help foster capital attraction for utilities, regulators need to consider these new risk levels in their deliberations.

A primary focus should be on debt and credit ratings. In their analysis of utility debt, credit rating agencies place considerable emphasis on the regulatory environment in which companies operate. History suggests that heightened risk levels in the financial markets will bring even greater scrutiny from rating agencies with regard to regulatory support of maintaining utilities' financial strength.

In the wake of the California energy crisis, Enron

The A Rating

By Steven M. Fetter

When I came to the Michigan Public Service Commission in 1987, the average regulated electric utility had a relatively solid credit rating—in the A- to BBB+ range, comfortably investment-grade—and utilities borrowed money for capital improvements rather easily. In 1992, close to 65 percent were A- or higher, and around 25 percent were in the BBB rating category. By 1998, 61 percent were A- or higher, with 31 percent in the BBB category.

Today the average rating for the sector is slightly above a BBB rating—still investment-grade, but now just 18 percent of electric companies are A- or higher, and more than 62 percent are in the BBB range.

The downward trend in utility ratings toward BBB seemed acceptable during the past decade—utilities could still borrow, relying on their regulated positions and growing demand; and dividend-paying stocks became more attractive to equity investors. It seemed that cash-flow and liquidity requirements no longer needed to be as high as for A-rated companies.

Today's capital markets, however, are experiencing a worldwide economic crisis, and the country is in severe recession. Indeed, the current economic turmoil has resulted in some utilities within the BBB category experiencing difficulty in accessing the capital markets. Even when capital is available, it is often at significantly higher costs and upon less favorable terms and conditions.

While the financial crisis has led to increases in debt and equity risk premiums for all utilities, these increases have been more consistently applied to utilities on the lower end of the credit rating scale, resulting in significantly higher cost of debt capital for BBB utilities than for A-rated ones. A December 2008 report released by J.P. Morgan, "Conservative Capital Structures: Reclaiming the Throne," opined that "generally, firms' lowest cost of capital is now reached at credit ratings that are about four notches higher than they were 18 months ago.... This trend is driven by a widening gap between the availability and costs of debt for higher and lower-rated firms." And as Garry Brown, chairman of the New York Public Service Commission says, "there is a clear relationship between a utility's bond rating and its ability to borrow at a reasonable cost, particularly in times of economic distress."

Unlike the broader industrial sector, which can delay capital investment in times of duress, electric utilities carry a responsibility to expend capital when needed to ensure safe and reliable service to customers. They do not have the option of substantially cutting back operations during difficult economic times. As Brown further notes, "Large capital programs... make it very important that electric utilities continue to have access to the financial markets, and regulatory policies should support utilities' ability to raise capital."

Flexibility in a Crisis

Here are two examples, admittedly extreme, that illustrate differing capabilities of an A-level utility and a BBB-level one. On September 11, 2001, Con Edison held an A+ credit rating. In the face of the terrorist events of that day, the utility was able immediately to initiate one of the largest infrastructure recovery efforts any industry has ever faced, without seeking special treatment from suppliers or lenders. The company's credit rating and outlook never stuttered as it proceeded to bring businesses in lower Manhattan back to full function.

In the other example, Entergy New Orleans had seen its corporate credit rating improve from BBB with a credit watch negative to BBB with a stable outlook. Then, in August 2005, Hurricane Katrina devastated the utility's infrastructure and customer base. Huge impacts, to be sure, but the utility also faced resistance from contractual counterparties to provide supplies and assistance. The utility soon filed for bankruptcy, allowing its parent company, Entergy Corporation, to provide $200 million in funds to support the long process of reorganization and recovery. (Entergy New Orleans emerged from bankruptcy in June 2007 with a BBB- rating.)

These examples came long before the current financial market crisis, but they demonstrate that a credit profile in the A category provides substantial flexibility for a regulated utility's management to respond to customer needs while respecting investor interests.

New Era

The discussions among executives, regulators, and Wall Street that focused on diversification in the 1980s and 1990s and industry restructuring in the 1990s and 2000s have now shifted to risk management, rate-recovery mechanisms, pre-approval, putting construction work in

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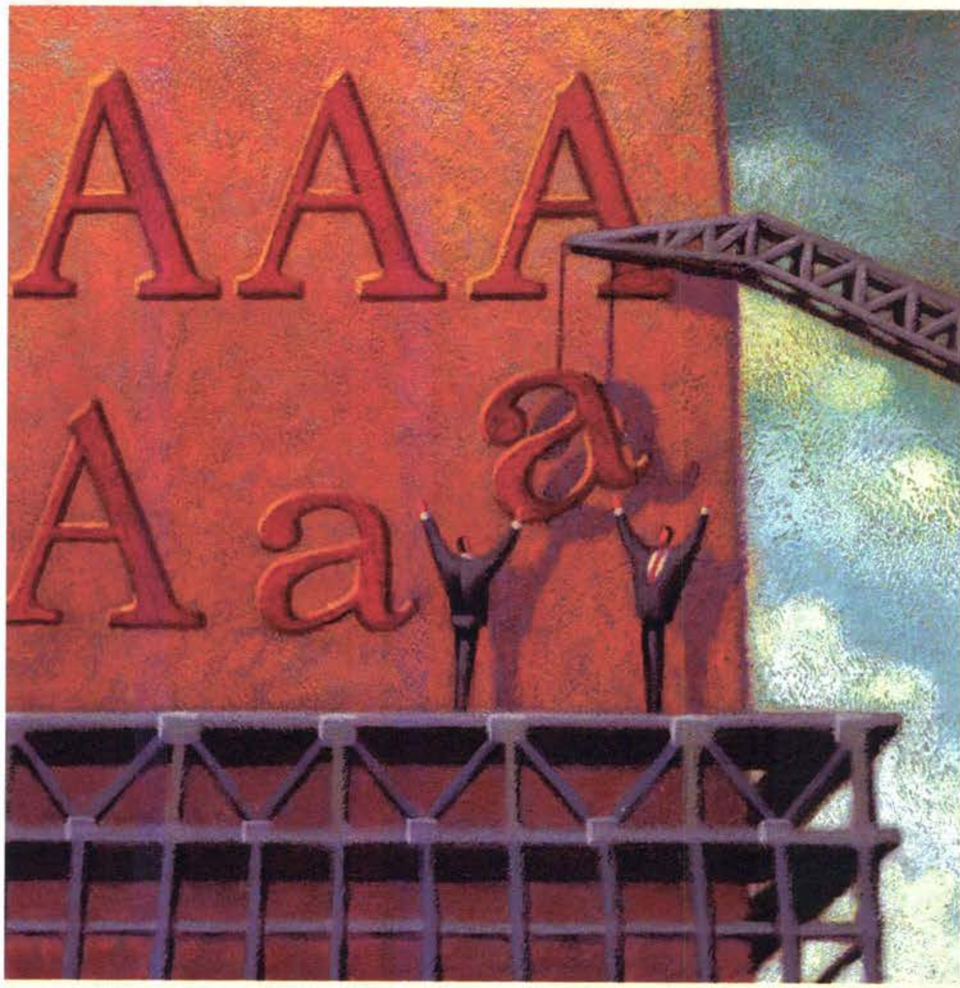
bankruptcy, and collapse of the merchant power sector in 2001-2002—and after considerable criticism of their failure to have anticipated the severe problems—rating agencies moved swiftly to alter credit ratings for merchant generation and utility companies. Those events were industry-specific, however, and today's circumstances have an impact on the global economy. Yet, the agencies—which once again are the object of public censure due to insufficient or inaccurate action in relation to the subprime mortgage situation—are more likely than not to err on the side of caution in their rating activities.

It is important to note that at the onset of the last major utility capex cycle in the 1970s and 1980s, the industry's senior debt was largely rated A and AA. As of December 31, 2008, with companies poised to embark on a significant new construction initiative in the context of a major financial crisis, the average senior debt rating was BBB. (See Figure 3.) The



Images.com

The bottom line is that electric utilities must collect sufficient cash flow through rates to maintain strong credit rating metrics. This is especially true for companies needing to proceed with major generation construction, notwithstanding the negative economic environment. S&P has highlighted cash flow as the single most critical aspect of all credit rating decisions. And liquidity is the lifeblood of day-to-day utility management flexibility.

To get the right amount can be rough going. In February 2009, to bolster liquidity and support their credit ratings, Ameren Corporation and Great Plains Energy substantially cut their dividends. The result on the equity side for those companies was a drop in stock price during the subsequent month of 35-45 percent. Certainly other utilities are watching the fallout from those decisions to determine whether internal cost-cutting can serve as more than a stopgap solution to liquidity stresses or whether they will have to follow the same volatile dividend reduction path.

Still, the A rating is positive for all stakeholders within the regulatory process—lower financing costs accrue to the benefit of customers through the ratemaking process; and the lower costs serve to maintain investor support and provide a degree of flexibility to respond to unforeseeable events.

Notwithstanding the current financial crisis, many utilities need to make substantial new capital investment, including a new generation of nuclear construction, to serve forecasted load growth. As a former state regulator and bond rater, I believe the optimal strategy is for utilities and their regulators to work in concert to ensure strong cash flow. Sustained and constructive regulatory support will be a major factor in how both investors and rating agencies will perceive electric utilities during these uncertain economic times. A shared commitment to financial stability will go a long way toward allowing A-rated companies to remain at that more secure level and provide hope for others that are endeavoring to move up to it.

progress into rate base, and other means of supporting utility credit profiles during periods of substantial capital investment. That change in focus should be encouraging for state regulators. Perhaps we have returned to a time when it would be in the interest of both companies and regulators to work in concert to support stronger credit profiles for regulated electric utilities (optimally in the A category), for the good of both consumers and investors. Even a strong BBB+ rating provides a measure of downside protection from the serious ills that would accompany a utility falling below investment-grade or even dropping to borderline BBB- status.

Steve Fetter is president of Regulation UnFettered, former chairman of the Michigan PSC, and former head of the global power group at Fitch Ratings.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY

OF

JAMES M. GARVIE

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
James M. Garvie
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address the testimony of Office of Public Counsel (OPC) Witness Garrett in which he inappropriately concludes that portions of at-risk pay expense and supplemental pension expense should be excluded from base rates. I will show that these expenses are not only reasonable and appropriate costs of service for ratemaking purposes, but also that the costs are a necessary part of Gulf's total package of compensation and benefits that allows Gulf to attract, engage, and retain a highly skilled workforce that focuses on the customers' interests.

ANNUAL AND LONG-TERM AT-RISK COMPENSATION

Q. Do you agree with Mr. Garrett's proposal to disallow a portion of Gulf's at-risk compensation?

A. No, I do not.

Mr. Garrett does not accurately evaluate Gulf's total compensation costs of base pay and at-risk pay. His proposal is not based on an appropriate market analysis or supporting data. By focusing on the mechanism of pay rather than the fact that the compensation expense Gulf requests in this case is market competitive, he disregards best practice in compensation program design and management, and illustrates a lack of understanding of how at-risk goals are used to drive employee behavior in ways that benefit our customers. Gulf's total compensation plan aligns the interests of all stakeholders to the direct benefit of our customers. In contrast, what Mr. Garrett suggests would create an unwanted misalignment of interests between customers and employees.

In addition, I note that Gulf Witness Deason explains in detail a number of additional objections to Mr. Garrett's proposal related to Florida Public Service Commission (Commission) policy and precedent. In this regard, Mr. Deason points out that in Gulf's last rate case, the Commission allowed annual at-risk compensation expense in recognition that customers do benefit from a financially healthy utility.

Q. Does Mr. Garrett suggest that Gulf's total compensation program is not competitive or that the costs of the program are unnecessary or unreasonable?

A. No. To the contrary, his testimony suggests that the Company would be required to continue to provide such at-risk pay in order to attract, engage and retain our talented employees in the competitive marketplace for utility labor. By implication, Mr. Garrett is acknowledging that the total compensation proposed by Gulf including at-risk pay is a reasonable cost of service. Mr. Garrett certainly does not provide any data or analyses to suggest that Gulf's total compensation is not competitive or that the costs are unnecessary or unreasonable.

Q. Is the design and competitiveness of Gulf's total compensation program aligned with the external market and are the costs necessary and reasonable?

A. Yes. As previously demonstrated in my direct testimony, Gulf's total compensation of base pay and at-risk pay is designed using sound compensation practice and principles. Through the use of compensation surveys published by recognized third-party sources, we determine the median total target compensation for each position. Based on the market, a portion of each job's total target compensation is subtracted out and allocated to at-risk pay based on goals that benefit our customers. As illustrated in Exhibit JMG-1, Schedule 2 of my direct testimony, when assessing both our base pay and total compensation of base pay and at-risk pay, Gulf is slightly below the median of the market.

In addition, Gulf had Towers Watson, a nationally recognized compensation and benefits firm, conduct a competitive assessment of the design of its total compensation program relative to external market prices. As shown in Exhibit JMG-1, Schedule 3, Towers Watson's conclusion is that Gulf's compensation plans, programs, and processes are comparable to and competitive with the utility industry.

Q. Given that Mr. Garrett does not present any evidence on the competitive position of Gulf's total compensation or that total compensation costs are unnecessary or unreasonable, what is the primary basis of his proposal to disallow a portion of annual at-risk pay?

A. Mr. Garrett argues primarily that some portion of Gulf's (necessary and reasonable) total compensation should not be allowed for recovery through rates because it is at-risk and tied to the financial performance of the Company.

Q. Do you agree with Mr. Garrett's opinion?

A. No. The combination of operational and financial goals tied to the at-risk portion of Gulf's total compensation plan allows the Company to properly balance the interests of customers and shareholders alike. It is important for our customers that the compensation plan includes both operational and financial goals.

Q. Why is it important to your customers that your employees have compensation goals that have both financial and operational components?

A. Our customers need safe and reliable service that is provided in the most cost efficient manner. A compensation plan that contained only operational goals might inappropriately drive employees to use more financial resources than necessary to provide operational success. Similarly, a compensation plan that contained only short term financial goals might inappropriately drive employees to make decisions that sacrifice long-term health for a short-term gain. Mr. Garrett's desire to artificially separate the operational components from the financial components, and the short term goals from the long term goals, shows a lack of understanding of a well-designed compensation plan.

Q. How does the design of Gulf's annual at-risk pay program benefit customers relative to the financial goals, and how do employees impact these goals?

A. A well designed at-risk pay program considers and aligns the interests of all stakeholders and engages employees to meet those interests. The annual at-risk pay goals that are based on financial performance are designed to support Gulf's financial health, which benefits our customers in a number of ways.

Focusing employees on actions that contribute to healthy financial performance benefits our customers. As Gulf Witness Teel has testified, providing investors with fair returns is necessary to maintain the Company's financial integrity. By focusing employees on keeping expenses reasonable through efficient purchasing practices, budget management, or effective use of personnel resources, our customers benefit through lower rates than would otherwise be the case and the Company's continued ability to raise capital on reasonable terms.

Q. Do you agree with Mr. Garrett's argument that many of Gulf's at-risk goals are "outside the control of most company employees"?

A. No. The total compensation plan is intentionally designed to include an appropriate mix of operational and financial goals, with both short and long term components. Mr. Garrett does not contest that the actions of our employees impact the compensation plan's operational goals. What he fails to properly consider is that our employees' actions similarly impact financial goals.

Gulf's employees at all levels make decisions everyday about how to best deploy the Company's resources and manage its budget. For example, an employee who chooses which contractor will be most cost efficient in getting work properly completed, an employee who decides on the most effective work methods for the task at hand, and an employee who works to stay within her budget are just some ways that our employees together will impact the financial goals of the Company. The key to the total compensation program is that, by having both operational and financial goals, measured on an annual and long term basis, our employees are driven not just to deliver safe and reliable electric service to our customers, but to do so in a financially responsible manner while continually striving to exceed our customers' expectations.

Q. Mr. Garrett contends that Gulf's compensation plan design includes components that do not provide any benefit to customers. Do you agree?

A. No. Gulf has properly designed its total compensation plan to provide a balance of both operational and financial measures that engage employees to meet the interests of all stakeholders. By balancing both operational measures and financial measures in the at-risk pay plan, employees are driven to not only serve the customer by delivering safe and reliable service, but to continue efforts to manage costs appropriately so that customers benefit through both excellent service and reasonable rates. Shareholders benefit from improved financial performance, but also from improved operational performance. Customers benefit from employee efforts to set and work within budgets that improve efficiency and reduce costs, ultimately resulting in lower customer rates than would otherwise be the case.

Q. Do you agree with Mr. Garrett's other at-risk compensation proposal to reduce by 50 percent that portion of at-risk pay tied to customer satisfaction based on his conclusions related to historical surveys performed by JD Power and Associates?

A. No. Gulf Witness Strickland demonstrates in her testimony that the Customer Value Benchmark is the more appropriate tool to measure Gulf's customer satisfaction levels. However, regardless of which tool is used to measure customer satisfaction, Gulf's at-risk goal related to customer satisfaction is appropriately designed to drive employees on a renewing annual basis to continually find ways to improve the customer experience. Mr. Garrett's argument is inconsistent with good compensation plan design. His argument that expenses for compensation tied to customer satisfaction should be disallowed for the 2014 test year because of allegedly lower than desired survey results from prior years essentially amounts to a penalty for past performance. Prior years' customer satisfaction survey results were appropriately addressed in the at-risk pay for those past years based on the level of achievement of the at-risk goals. Disallowing a portion of at-risk pay tied to customer satisfaction in future years because of allegedly poor results in past years would be antithetical to the compensation plan's purpose of motivating employees to improve customer service going forward.

As Ms. Strickland notes in her testimony, the actual customer survey results have improved to a much greater degree than that suggested by Mr. Garrett. Gulf believes that its total compensation program is a key factor in achieving these improvements. Disallowing any portion of this compensation expense would be inappropriate for employees and customers alike.

Q. Turning now from Mr. Garrett's proposed adjustment to Gulf's short-term at-risk compensation to Mr. Garrett's proposed adjustment to long term at-risk compensation, please respond to Mr. Garrett's argument that the entirety of the long term portion of Gulf's at-risk compensation plan should be disallowed.

A. As previously discussed in my testimony and that of other Gulf witnesses, customers benefit from a financially healthy company. It is therefore critical to measure financial health in both the short term and longer term to help ensure that the decisions made by the employees are optimized not merely for short term benefits, but to sustain the Company in the long run. This is especially true in the utility industry, where decisions related to infrastructure and other major projects have long-lasting financial consequences to all of the stakeholders, including our customers.

Customers would not ultimately benefit if Gulf were to drive its employees to sacrifice long term financial health for short-lived benefits. When our employees make decisions that impact the Company financially, we want to motivate them to consider the longer-term effects of those decisions. For a simplistic example, let's suppose that a company is faced with needing to purchase a new piece of equipment, and the marketplace for this equipment allows the company several choices when deciding which equipment to purchase. If the company has an at-risk compensation program that contains only operational goals, the lack of financial goals may motivate employees to purchase a more expensive piece of equipment, even if the marketplace offers less expensive equipment choices that equally meet the company's needs. Now, suppose that this same company has an at-risk compensation program with both operational and short term financial goals, but no long term goals. Under this scenario, the lack of long term goals may motivate employees to purchase equipment that has the lowest initial price without regard to whether that choice of equipment would likely, in comparison to a slightly more expensive model, cost more in the long run because of comparatively poorer quality or design. Finally, a company with an appropriate total compensation program that incorporates operational and financial goals, measured both annually and long term, will motivate employees to purchase the equipment that will best serve the customers' needs in a cost effective manner not only during the year in which the equipment was purchased, but also in later years.

A total compensation plan without any long term financial goals would not be in our customers' best interests.

By designing the at-risk portion of the total compensation plan to include both annual goals and longer term goals, an appropriate balance is achieved whereby employees are driven to deliver safe and reliable electric service to our customers in a manner that is economically efficient for our customers both now and in the years that follow.

Q. What is your response to Mr. Garrett's contention that the officers of a corporation typically place the interests of the shareholders above that of customers on the grounds that officers have a duty of loyalty to shareholders as opposed to customers?

A. I disagree. Mr. Garrett's statements imply that officers of a corporation exist only for the benefit of a shareholder, whereas only the lower level employees care about the customer. This is simply not accurate. As Gulf Witness Stan Connally has testified, as well as many others of Gulf's witnesses, our customers are at the center of everything that Gulf does, and that customer-centric approach is <u>led</u> by Gulf's officers. Gulf exists to serve its customers.

It is important to keep in mind that the long term goals portion of Gulf's at-risk compensation is not limited merely to the officers of the Company. This portion of the pay plan extends to 121 employees who have the most influence on making the types of decisions that may affect the longer term health of the Company. These 121 employees include, for examples, principal engineers, staff accountants, maintenance managers, customer care center supervisors, district engineering supervisors, air quality programs supervisor, transmission construction supervisors, district managers, plant managers, and many others. These are individual contributors, front line supervisors and managers who are clearly responsible for meeting our customers' interests.

All of our employees, including Gulf's officers, have our customers at the center of all we do.

Q. When you said earlier that Gulf's total compensation, which includes both base and at-risk pay, is appropriately market competitive and targeted to the median of the market, was the long term portion of the at-risk pay included as a part of this analysis?

A. Yes. Mr. Garrett does not contest the reasonableness of the amount of total compensation, which includes the long term piece of at-risk compensation. Indeed, the amount of compensation sought in this rate case attributable to the long term portion of at-risk compensation is only that amount required by Gulf to remain market competitive. By focusing on the mechanism that triggers the payment as opposed to the total expense requested for compensation, Mr. Garrett either misses the point or is deliberately trying to obscure the facts.

If Mr. Garrett's proposal is accepted, Gulf would have to consider completely redesigning its compensation program such that the current program of base pay plus at-risk pay is eliminated in favor of a base pay only model. Gulf could conceivably request the same dollar amount of compensation expense for the 2014 test year as it currently seeks so as to remain market competitive from a dollar standpoint, and thereby avoid Mr. Garrett's current argument that a portion of the compensation program should be disallowed in rates simply because it may be affected by employee performance on financial goals. However, eliminating a powerful tool that drives employees to put the customer at the center of all we do and sustains the financial integrity of the Company is simply not in the best interest of our customers. It would result in higher fixed costs and poor alignment of interests.

Gulf's existing total compensation program, including annual and long term at-risk pay, is the best method for Gulf's customers because it allows Gulf to retain and attract qualified employees at market competitive compensation amounts, while allowing management to drive employee behavior so that employees continually keep the customers' interests at the center of their attention, serving the customers both in the short term and in the years to come.

SUPPLEMENTAL PENSION PLAN

Q. In his testimony, Mr. Garrett proposes that the supplemental executive retirement plan expense be disallowed. Please describe the supplemental plans.

A. The Supplemental Benefit Plan (SBP) and Supplemental Executive Retirement Plan (SERP) were established to provide participants total retirement income benefits from company-sponsored sources, comparable to what other employees receive as a percent of base salary plus annual at-risk pay.

Q. Why does Gulf provide these types of plans?

A. Gulf provides these plans due to limitations imposed by the Internal Revenue Code (IRC) on the deductibility of benefits associated with annual compensation levels over $255,000. This annual compensation limitation exists solely for government revenue and tax policy purposes and has nothing to do with the level of benefits that should be provided.

Q. Are these plans intended to provide additional or greater benefits than other employees receive under the general pension plan of the Company?

A. No. These plans are comparable to what other employees receive as a percent of base salary plus annual at-risk pay. Without these plans, employees whose pay exceeds the IRC specified level would receive significantly less pension, as a percentage of pay, than other employees.

Q. How do you respond to Mr. Garrett's argument that these pension costs are merely discretionary costs of the shareholders and therefore not necessary for the provision of utility service?

A. I disagree. Contrary to Mr. Garrett's unsupported statement, the amounts needed to fund these retirement plans are in fact necessary for the provision of utility service. A company of Gulf's size and scope cannot operate effectively without experienced and qualified employees to lead and manage the organization. Gulf has a responsibility to deliver safe and reliable electric service to the hundreds of thousands of its customers in Northwest Florida, and I do not think there can be any valid dispute that in order to carry out this responsibility, Gulf needs to be able to attract and retain individuals who are able to effectively lead and direct its employees. Customers benefit from the efforts of the leaders of the Company. In order to remain market competitive, Gulf must be able to offer these employees competitive retirement benefits commensurate with their compensation.

Q. Do you agree with Mr. Garrett's basis for his proposed disallowance?
A. No. The supplemental benefit plans are intended to provide fair, equitable and competitive benefits to all Gulf employees at all levels. As such, they are reasonable and appropriate expenses that should be included in base rates.

CONCLUSION

Q. Does Mr. Garrett provide any evidence to challenge the overall reasonableness of Gulf's total compensation and benefits package?
A. No, he does not. He has not provided any evidence that the costs of Gulf's compensation and benefit programs are unnecessary or unreasonable. Gulf's projected expenses for the at-risk portion of total compensation, and supplemental retirement benefits are reasonable and appropriately included in rates.

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

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

RAYMOND W. GROVE

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Raymond W. Grove
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Ray Grove. My business address is One Energy Place, Pensacola, Florida, 32520 and I am the Manager of Power Generation Services for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The primary purpose of my testimony is to address the testimony of Federal Executive Agencies (FEA) Witness Greg R. Meyer, in which he proposes a $5.7 million reduction to Gulf's projected 2014 Production Operations and Maintenance (O&M) budget.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes. I am sponsoring Exhibit RWG-2. It was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge and belief.

I. PRODUCTION O&M

Q. Please place Mr. Meyer's proposed adjustment to Production O&M expenses in context.

A. Based upon the rigorous budget process discussed in my direct testimony, Gulf has proposed a Production O&M budget of $106,736,000 for the 2014 test year. The elements of that budget estimate are shown below:

Baseline Materials	$10,006,000
Baseline Other	51,593,000
Baseline Labor	29,476,000
Total Outages	17,636,000
Special Projects	155,000
Adjustments	(2,130,000)
Total Budget	$106,736,000

Mr. Meyer accepted all of the elements of Gulf's proposed 2014 Production O&M budget except for two: Baseline Materials and Baseline Other. For those two elements, he made an adjustment that reduces the amount to the highest historic annual level for each of those expense categories during the years 2008 through 2012. Coincidentally, those both occurred in 2011. Mr. Meyer's resulting 2014 Production O&M budget is therefore a hybrid that uses 2014 projected values for Baseline Labor, Outages, Special Projects and Adjustments, and uses 2011 historical values for Baseline Materials and Baseline Other.

Q. Do you have any overall comments concerning Mr. Meyer's Production O&M testimony?

A. Yes. Mr. Meyer's approach is analytically unsound. If his technique were applied consistently as a way to forecast Gulf's Production O&M expenses, he could and should have used it for Gulf's entire Production O&M budget, not just two selected elements. In fact, if he had applied the same methodology to Gulf's entire Production O&M budget, his resulting total Production O&M budget would have been larger than the total Production O&M budget proposed by Gulf.

Mr. Meyer's adjustment is entirely backward looking and therefore fails to address the only pertinent question before the Commission – whether Gulf's 2014 level of Production O&M expense (and the Baseline Materials and Baseline Other estimates within the total) is representative of conditions going forward when Gulf's new rates will be in effect.

Prior to making his proposed adjustment to Production O&M, Mr. Meyer alleges that, "over-forecasted expenses in rates provide a benefit to shareholders as they provide more certainty that the authorized rate of return will be achieved." This unwarranted accusation has no place in this proceeding. As the employee with primary responsibility over the budgeting process employed by the Production function at Gulf, I am stating unequivocally that Gulf Power Company did not intentionally over-forecast Production O&M expenses in the 2014 test year to benefit shareholders. Gulf's forecast of 2014 Production O&M expenses is the level of expenses that we at Gulf maintain are necessary, reasonable and prudent in order to continue to provide adequate service to our customers.

Q. How does Mr. Meyer's total Production O&M expenses of $101 million compare to the Production O&M benchmark level of expenses provided to you by Gulf Witness McMillan?

A. Mr. Meyer's suggested Production O&M expenses of $101 million are far below, $11.3 million below, the 2014 Test Year Benchmark for Production O&M of $112.3 million. However, it is even more telling that Mr. Meyer's Production O&M expense for 2014 is more than $5.9 million below the level of 2012 Production O&M expense allowed by the Commission in Gulf's last rate case two years ago. In that case the Commission found the reasonable and prudent 2012 level of Production O&M expense to be $106.9 million. The level of Production O&M expenses that results from Mr. Meyer's adjustments is simply unreasonable.

II. BASELINE MATERIALS AND BASELINE OTHER

Q. What adjustment is Mr. Meyer proposing for Production Baseline Materials and Baseline Other expenses?

A. Mr. Meyer recommends that instead of Gulf's 2014 budget based level of Baseline Materials of $10,006,000, the Commission only allow Gulf its actual 2011 level of Baseline Materials of $8,514,000. He therefore recommends a disallowance of $1,492,000. Using the same approach, Mr. Meyer recommends that instead of Gulf's 2014 budget based level of Baseline Other expenses of $51,593,000, the Commission only allow Gulf its actual 2011 level of Baseline Other Expenses of $47,393,000. He therefore recommends an additional disallowance of $4,200,000. Taken together, Mr. Meyer recommends total Production O&M disallowances of $5,692,000. A disallowance of this magnitude will not allow Gulf to fully and appropriately fund the level of activity required in 2014 and beyond for Gulf to efficiently and reliably serve Gulf's customers.

Q. Is Mr. Meyer's method an appropriate method for determining the appropriate level of Baseline Materials and Baseline Other expenses necessary to maintain a generating fleet?

A. No. As I have stated in my direct testimony, our multi-step budget process begins at the plant level and is driven by the plant personnel who maintain and operate our generating fleet. They operate and maintain this equipment every day. They are the experts, and when their expertise is coupled with a detailed review by experienced plant and production organization management, including Gulf's Senior Production Officer, it provides a more robust process of developing a budget. This is a far superior approach to budget development than simply saying that costs must be excessive if they are higher than those experienced by Gulf three years ago.

Mr. Meyer's proposal does not include any analysis of the facts underlying why Baseline Materials and Baseline Other expenses have varied over the period 2008-2012 or any information as to how reduced levels of Baseline Materials and Baseline Other expense were related to higher-than-budgeted outage costs in a number of those years. Mr. Meyer's approach of just looking at the raw numbers without any apparent understanding of the ongoing dynamics during those years results in an uninformed and ill-advised adjustment.

It is not unusual for Gulf, in the management of its expenses after the budget process, to redirect expenses to other categories within the Production budget or make informed decisions as to whether to spend the entire Production budget. As I explained in my testimony in Gulf's prior rate case, in the years 2008 through 2010, Gulf made informed decisions not to spend its entire Production O&M budget. It did so in the interests of its customers. Gulf was attempting to delay the need to ask for base rate relief during the Great Recession. That discussion from my testimony in the last case is attached as Schedule 1 of my Exhibit RWG-2.

Mr. Meyer notes only that the levels of these budget elements have varied up and down; he makes no effort to understand why they varied or whether any of the levels of actual expenditures would have been appropriate if Gulf had not been trying to benefit its customers by avoiding a rate case. After noting that the levels of these expenditures have varied historically, Mr. Meyer simply takes the highest historical level of expenses in the past five years, the 2011 level, and assumes that such a three year old level of expenses will be sufficient into the future.

Once again, Mr. Meyer is just looking at numbers and does not have any knowledge of Gulf's system. He points out that in 2011 and 2012 Gulf budgeted more Baseline Material and Baseline Other expenses than it actually spent, but he fails to go behind the numbers. In 2011, Gulf spent less Baseline Material and Baseline Other expenses than budgeted because those funds were redirected into outage costs that had to be performed. In 2011, Gulf spent $3.2 million more for outages than it had budgeted (a fact omitted from Mr. Meyer's discussion), and those dollars came from Baseline Materials and Other. So, this is not an issue of Gulf "over-forecasting;" this is an example of Gulf effectively managing its business.

In 2012 Gulf's actual expenditures in Baseline Materials and Baseline Other were also less than Gulf budgeted due in large part to the fact that anticipated revenues did not materialize. Once again, the reduced spend demonstrates Gulf was effectively managing its resources. As shown in Gulf Witness Teel's direct testimony in this docket, "In fact, Gulf's achieved ROE has been below the bottom of the currently authorized range since the beginning of 2011 and without rate relief, is projected to be below that range for the entire period 2011 – 2014." This is the range found fair and reasonable by the Commission when it last set the Company's base rates in 2012.

Mr. Meyer's consistent focus on numbers from the past without any appreciation of the factors that inform those numbers and his complete failure to focus on the future levels of expenses necessary to run the Production function is very troubling.

The real issue at hand is not how much was required to maintain the fleet in the past; the real question is - are the dollars requested in the test year representative of the dollars Gulf will need to ensure that our customers' electrical needs are served by a reliable and efficient generating fleet in the future? The answer to that question is yes.

IV. PLANNED OUTAGES

Q. What adjustment is Mr. Meyer proposing for Planned Outages?

A. Mr. Meyer is not recommending an adjustment in planned outages. However, in his testimony he states he "is concerned that the level of 2014 may be inflated due to the extremely low level of expenses forecasted for 2013." Mr. Meyer's concern is baseless. Gulf's 2014 level of expenses for planned outages is not inflated. Moreover, Gulf has not increased its level of planned outage expenses in 2014 because it was successful in reducing budgeted planned outage levels in 2013 as addressed in my direct testimony on pages 22 – 24.

Q. How do the planned outage expenses in the Test Year (2014) compare to Gulf's last rate case request for planned outages?

A. In our last rate case, Gulf projected to spend $23.1 million for planned outages in that test year (2012). In this proceeding Gulf is requesting $17.2 million, or a reduction of almost $6 million.

Q. How do Gulf's projected levels of outage expenses for 2014 and 2015 in this case compare to the levels projected for those same years in Gulf's last rate case?

A. They are lower, providing yet more evidence that Gulf's current budget is reasonable. In our last rate case, Gulf had projected to spend $20.2 million in 2014 for planned outages and in this case Gulf is requesting $17.2 million, or a $3 million reduction. The same relationship holds true for 2015 where Gulf budgeted $20.6 million in the last rate case and only $15.2 million, or a $5.4 million reduction in this case. Clearly this shows Gulf has not inflated the test year Planned Outage budget. In fact, this demonstrates that Gulf has taken appropriate actions to adjust the planned outage dollars to reflect our actual needs going forward.

VII. CONCLUSION

Q. Please summarize your testimony.

A. Gulf's Production O&M expenses should not be adjusted.

Gulf has budgeted Production O&M expenses, including Baseline Materials and Baseline Other expenses, that (a) were prepared by knowledgeable employees who operate Gulf's power plants and know the level of expenses necessary and appropriate to serve customers reliably, (b) were prepared in a rigorous budget process reviewed by informed and capable executives, and (c) are forward looking and representative of future conditions when Gulf's new rates will be in effect. Gulf's 2014 total Production O&M expenses are lower than the amount of Production O&M allowed by the Commission in Gulf's last rate case for 2012 and are well below the Commission's O&M benchmark level of Production O&M expenses.

In contrast, Mr. Meyer's proposed adjustments to Gulf's 2014 O&M Production budget (a) were prepared focusing solely on numbers without the benefit of the facts underlying historic expenditure levels, and (b) are backward looking and completely fail to consider the legitimate reasons why Gulf spent less than budgeted for several years and why Gulf needs to spend more in the future to reliably serve its customers. Mr. Meyer's adjustments are analytically unsound. This results in an overall level of Production O&M expenses that would be: (1) lower than the total Production O&M expenses if he had applied his approach to all Production O&M expenses rather than just cherry-picking two categories of expense, (2) lower than the Production O&M expenses allowed in Gulf's last rate case, (3) much lower than the Production O&M expenses suggested by the O&M benchmark, and most importantly (4) below the level of Production O&M expenses determined to be necessary through Gulf's rigorous budgeting process.

The important question facing the Commission is: Are the Production expenses included in the 2014 test year representative of the dollars that Gulf will need to provide our customers the efficient, reliable generating resources that they expect and deserve? The answer to that question is yes.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

Exhibit

A. In our prior rate case, Plant Smith Unit 3 was in its first full year of operation. As discussed later in the benchmark variance justification for Production Other, the budget for Plant Smith has risen significantly since the last rate case. Similarly, the average projected cost associated with Smith 3 in the period 2011-2015 of $7.3 million is $1.7 million higher than the average cost in the historical period 2006 through 2010 of $5.6 million. Once again, this increase is being driven by an increase in maintenance expense that is directly related to repairing equipment that was relatively new in the historical period.

Q. The fourth reason you gave for the increase of Production O&M expenses between the 2006-2010 historical period and the 2011-2015 projected period was the addition of new generating units (Perdido). Please address how this affects the relative levels of Production O&M expenses in those time periods.

A. Gulf added new generation at Perdido in October 2010. There were no O&M expenses associated with this facility in the years 2005 through 2009. In addition, there was less than a full year of expenses in 2010; however, the years 2011 through 2015 fully reflect the annual O&M expense associated with the Perdido facility.

Q. The final reason you gave as to why the 2012 level of Production O&M expenses is more representative of ongoing levels of Production O&M levels than the levels of Production O&M levels during the period 2006-2010 relates to Gulf's efforts to control expenses to avoid asking for a base rate increase at a time when Gulf's customers were struggling through the worst economic downturn since the Great Depression. Please address that point in more detail.

A. This is best explained by looking at the allowed Production O&M expenses in the 2002/2003 test year, the actual Production O&M expenses in 2006 through 2010 and the budget levels of Production O&M expenses for 2011 through 2015. There was a clear trend of an increase in Production O&M expenses from the 2002/2003 test year level of $76,996,000 in Gulf's last rate case through the actual level in 2008 of $88,424,000. (Actual Production O&M expense for 2006 through 2010 is shown on Exhibit RWG-1, Schedule 7). Then, in 2009, Gulf decreased its Production O&M expenses to $84,209,000. This $4,215,000 reduction in Production O&M expenses was part of the effort that Gulf undertook to defer its need to ask for base rate relief.

This reduction in Production O&M expenses in 2009 was not done without careful deliberation. We prioritized our maintenance decisions to address critical issues. We took the approach of trying to perform as much maintenance as we could on our larger units that are dispatched more often, and we did not perform selective maintenance on smaller units which, if they experienced forced outages, would not as severely impact overall reliability.

A similar effort was undertaken in 2010, but in that year we could no longer drive down Production O&M costs. They had to increase.

Although our internal budget process had developed and submitted a Production budget of $94,665,000, we were able to hold actual expenses to $92,889,000. Once again, we prioritized maintenance, but we did it to avoid having to ask for a base rate increase during a time of weak economic recovery and high unemployment. We made calculated risk assessments of what maintenance had to be performed. Our EFOR performance indicator shows Gulf was able to make these reductions while we continued to maintain excellent performance.

Q. Does the level of Gulf's actual expenses in 2009 and 2010 indicate that it is not necessary for Gulf to spend Production O&M at the levels suggested by its 2011 budget process?

A. Absolutely not. A well maintained system such as Gulf's can forego some scheduled maintenance for a limited period of time without a severe risk of adverse consequences. However, it cannot forego scheduled maintenance over an extended period of time without predictable adverse consequences in unit performance, system reliability and ultimately customer satisfaction. Gulf has no prudent choice other than to increase Production O&M expenses to avoid these adverse consequences. Continued operation at these levels of Production O&M is simply too risky for our customers. It is time to increase Gulf's Production O&M expenses and recognize those levels on a going forward basis.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY

OF

PETER S. HUCK

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Peter S. Huck
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Peter Huck. My business address is 411 East Wisconsin Avenue, Milwaukee, Wisconsin and I am a Senior Manager of the electric and gas utility practice employed by American Appraisal, Inc. (American Appraisal).

Q. Are you the same witness who presented direct testimony in support of Gulf depreciation rates in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My testimony rebuts the direct testimony of Office of Public Counsel (OPC) Witness Pous, specifically, the portion of Mr. Pous' direct testimony that addressed both my direct testimony and the Depreciation Study (Study) I performed on behalf of Gulf Power Company (Gulf or the Company). The portion of Mr. Pous' testimony that addressed dismantlement is addressed by Gulf Witness Deason. The absence of any critique of this aspect of Mr. Pous' testimony should not be interpreted as my agreement with Mr. Pous; it is merely an acknowledgement that I did not prepare the Company's dismantlement study.

Q. Please explain how your rebuttal testimony is organized.

A. My rebuttal testimony consists of five sections. I begin with an Overview that addresses (a) some of the disparaging general observations offered by Mr. Pous outside of his specific adjustments, (b) some of the general criticisms that Mr. Pous offers of my techniques and the Study I presented on Gulf's behalf, and (c) Mr. Pous' inaccurate suggestion that Gulf may have tried to influence the results of my Study. The remaining four sections of my testimony correspond to four of the five sections of Mr. Pous' testimony. In those sections I address the specific adjustments that Mr. Pous makes to my Study. The section of Mr. Pous' testimony I do not address is his section on Production Plant Dismantlement, as that is outside the scope of my Study. I also did not address Mr. Pous' amortization of Account 303 – Intangible Plant - Software, as that is outside the scope of my Study.

I. OVERVIEW

Q. Earlier you stated that you respond to some disparaging statements that Mr. Pous makes in his testimony. Which of those statements are you rebutting?

A. Certainly not all such statements, only the ones that I perceive are meant to improperly color the Florida Public Service Commission's (FPSC or the Commission) perception of depreciation and Gulf's motives.

Q. Please give an example.

A. At page 8 lines 2-18 Mr. Pous offers an "additional observation" about electric utility's financial self-interest. While I certainly agree that the Commission should review a utility's practices and studies to ensure that current customers are not called on to pay more than their appropriate share of depreciation, I take issue with the immediately preceding statement that "a utility has an incentive to favor higher depreciation expense and higher depreciation reserves." My experience has not been that at all. My utility clients consistently attempt to "get the reasonable and correct answer" for depreciation. That is certainly the impression I have regarding Gulf from having worked with them over the past 9 years.

Q. In retaining you or providing data you used in developing your Study, did Gulf suggest to you that it needed or desired either higher depreciation expense or a higher depreciation reserves?

A. No. I was asked for my independent assessment. Gulf made no suggestions about the level of depreciation expenses or reserve, other than they expected the Study to be done correctly.

Q. This is the third Study you have performed for Gulf. Has Gulf pushed for higher depreciation rates over those 9 years?

A. No, they have not. Gulf has consistently asked for my best judgment as to what both current and prospective customers should pay for investment in property to be correctly recovered. My experience with Gulf has not shown them to have pushed for higher depreciation rates or higher depreciation reserves than they need. Indeed, Gulf's current reserve balance is negative when compared to Gulf's theoretical reserve, suggesting their depreciation rates historically may have been a bit too low, not too high.

Q. What other general criticisms offered by Mr. Pous do you rebut?

A. There are three other general statements critical of both me and Gulf that warrant brief rebuttal. The first two statements address the quality of my work, although they are attributed to "the Company."

At page 53 Mr. Pous argues that the Company makes "generalized statements" about the fits of curves and "provides very limited specific evidence that can be reviewed."

At pages 54- 58 Mr. Pous offers a general critique not of my simulated (SPR) method analysis but of the presentation of my results, suggesting it "is anything but standard" and concluding that "even a relatively seasoned depreciation analyst might have difficulty analyzing what has been presented."

A third statement, also on page 53 requires rebuttal for several reasons: (a) it is factually inaccurate and (b) it poses alternative reasons for the inaccurate statement that suggests that either my analysis is deficient or that I and/or Gulf had an improper motive.

Q. Please address Mr. Pous' argument that you employ generalized statements rather than providing specific evidence.

A. Given Mr. Pous' generalized statements and lack of supporting evidence in his testimony, I find this criticism ironic. My Study was performed over a lengthy period of time using extensive and detailed records. Its results are reported in two separate volumes. My Study follows industry practices and it is properly reported.

Not every specific judgment employed is or can be disclosed in the resulting Study. Necessary first steps in a Study are the processing of data using quantitative methods. More than that, depreciation is a matter of informed and educated judgments, and documentation of every specific consideration in the selection of depreciation rates is impractical and unnecessary.

Q. Please address Mr. Pous' general critique of the presentation of your results, suggesting it "is anything but standard" and concluding that "even a relatively seasoned depreciation analyst might have difficulty analyzing what has been presented."

A. My presentation is my standard presentation, which has been reviewed by and relied upon by many regulatory commissions, including this Commission on two prior occasions. Mr. Pous' direct testimony, where he gives extensive explanations for the decisions I made belies the remainder of his criticism that a relatively seasoned depreciation analyst might have difficulty analyzing what has been presented. He had no difficulty understanding my analysis, drafting over fifty pages of specific adjustments in his testimony.

Q. Please address the following statement Mr. Pous makes at page 53 of his testimony: "the Company often ignores the 'best' fitting results either because it did not investigate those life-curve combinations or because it results in higher ASLs than it is willing to propose."

A. The first part of the statement is fundamentally inaccurate. First, it was not "the Company" but me that did the analysis. Second, I did not ignore best fitting results. My work papers contained in the Study show life and curve combinations representative of the data, including, though not limited to my conclusion. In the course of my analysis, I routinely considered other life and curve combinations. Like any other analyst, my final work papers do not show all life and curve combinations that were evaluated.

Mr. Pous' statement not only misstates the facts, but also compounds that error by attributing inappropriate behavior to either me or the Company. I did investigate life-curve alternatives, and the suggestion that I failed to do so is simply wrong. Suggesting that either I or the Company ignored curves because they resulted in higher average service lives (ASL) than we wanted to propose inappropriately attacks both my integrity and that of the Company.

I want the record to be perfectly clear on this. Going into this analysis, I had no specific ASLs that I wanted to propose. The lives I chose were those I thought to be correct for depreciation and were the result of my analysis, not any personal bias. Similarly, Gulf did not suggest any desired ASL (or other) results to me for the Study.

II. PRODUCTION PLANT INTERIM RETIREMENT RATES

Q. Turning now to the Production Plant Interim Retirement Rates, how many such rates did you develop and how many does Mr. Pous contest?

A. I developed and used 17 interim retirement rates (IRR) for Production accounts. Out of those 17 rates, Mr. Pous accepted 15 and contested two.

Q. Let's look at the first contested Production interim retirement rate. What IRR did you and Mr. Pous propose for Steam Production Account 312 – Boiler Plant Equipment?

A. Mr. Pous proposed an IRR of 0.65 percent in place of the 1.00 percent IRR that I recommended for the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. I recommend the Company's 1.00 percent rate be adopted by the Commission. The historical IRR data specific to the Company is, as agreed by Mr. Pous, significantly greater than 1.00 percent, more than two times what is proposed by Mr. Pous. Mr. Pous cites the recent emission control additions and asserts that they resulted in unusual levels of retirements. Mr. Pous did not present specific data as to what were the specific retirements that resulted from the recent emission control additions. He did identify a single year's retirements, 2009, as requiring adjustment.

Mr. Pous identified 2004 as the start of the recent large additions. It should be noted that the historical IRR of the 10 years prior to 2004 was 1.20 percent, some 85 percent greater than Mr. Pous' proposal.

Mr. Pous also asserted that IRR will be lower in the future than 1.00 percent because of the larger plant balance that currently exists. No facts or data were presented by Mr. Pous to support that assertion. Future retirements from emission control systems, essentially complex chemical plants, could be as much or greater than the other assets in Account 312 and this real possibility was not considered by Mr. Pous in his analysis. Another possibility apparently not considered by Mr. Pous is that there may be future additional emission and pollution control systems necessary to meet future environmental requirements that could trigger even more retirements.

If the historical IRR data specific to the Company is adjusted for the period 2004-2012 by using the average retirements of the years adjacent to 2009, the procedure Mr. Pous says should be followed (Page 28, lines 16-20), the result is 1.33 percent, not the 0.65 percent reported by Mr. Pous. Also, Mr. Pous' reliance on just 4 years of data, one of which he adjusts, is not convincing when so much other historical data specific to the Company is available.

Other possible adjustments based on the assertions by Mr. Pous were also made for comparison purposes, such as excluding the two largest retirements, a very severe adjustment, or substituting averages for them. The results of such adjustments during the last 10 years of actual historical retirements were an IRR of 0.94 percent and 1.11 percent; still not the 0.65 percent arrived at by Mr. Pous.

While Mr. Pous resorted to comparison to other companies in his support for his proposed IRR for Account 343, he did not do so here for Account 312. In my experience, the most typical IRR for Account 312 is near to or at 1.00 percent. I note that 0.94 percent was adopted for Account 312 by this Commission in the recent Florida Power & Light (FPL) case.

Q. What rate did Mr. Pous propose for Other Production Account 343 – Prime Movers for the combined cycle plant?

A. Mr. Pous proposed an IRR of 1.00 percent in place of the 2.00 percent IRR recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. I recommend the Company's 2.00 percent rate be adopted by the Commission. The historical IRR data specific to the Company is greater than 2.00 percent. Mr. Pous states there is limited experience for new combined cycle units. In this case, there is more than 10 years of experience. Gulf Witness Burroughs explains more fully Gulf's combined cycle experience. Even excluding all the retirements of 2005-2007 when design related turbine failures occurred, the historical IRR is still greater than the 2.00 percent IRR I propose.

Mr. Pous also asserts that the combined cycle units should not have the same level of retirements as coal-fired units, implying they should be lower than coal-fired units. No support was offered for this assertion. Scheduled major outages of the combustion turbines (CT) units at a combined cycle plant are dependent largely on their usage and occur on a short cycle when the combined cycle plant is operating as it was designed to. These scheduled outages result in significant retirements, at a relative level greater than at coal-fired plants. The Company IRR data for Account 343 shows retirements of nearly $19,000,000 in 2010. The unit had another maintenance outage in early 2013, which resulted in total retirements of $20,000,000, as discussed by Gulf Witness Burroughs. The actual total retirements of almost $20,000,000 were recorded in Account 343 and were considered in my analysis.

As indicated by the retirements of 2010 and 2013, the $2,300,000 annual interim retirements indicated by my recommended 2.00 percent IRR are conservative and the $1,200,000 of annual interim retirements from Mr. Pous' 1.00 percent proposal are significantly less than what is required.

Q. Mr. Pous also invokes the IRR for Account 343 approved in the recent FPL rate case as support for his position. Please comment.

A. Mr. Pous states that this Commission adopted a 0.57 percent IRR for

Account 343 in the recent FPL case. This statement, while accurate, is misleading.

Mr. Pous does not point out that the 0.57 percent IRR approved for FPL is a composite rate applied to both combined cycle units and CT plants. CT plants typically have an IRR lower than 0.57 percent. So, when their IRR is combined with the IRR for newer combined cycle plants, the resulting composite IRR is lower. In the Gulf case, the IRR for Account 343 was separated between the combined cycle plant and the CT plant. The IRR I recommended to the Company for Account 343 of the CT plant was 0.30 percent, much lower than my recommendation of 2.00 percent for combined cycle Account 343. In referring to the FPL rate, Mr. Pous did not acknowledge or make an attempt to analyze the effect of the composite IRR on FPL combined cycle units for "an apples to apples" comparison. Further, in citing the IRR from the FPL case, Mr. Pous misleadingly did not include Account 343 capitalized spare parts, which had an IRR of 15.65 percent. Again, this indicates that Mr. Pous is not making "an apples to apples" comparison. Mr. Pous' simple reference to the adopted IRR in the FPL case is, in my opinion, of little direct use in this case.

III. PRODUCTION PLANT INTERIM NET SALVAGE

Q. Turning now to a new subject, what rate did Mr. Pous propose for net removal of interim retirements of Steam Production?

A. Mr. Pous proposed a net removal of 20 percent for the interim retirements of Steam Production. I propose a 25 percent net removal for the interim retirements of Steam Production.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. Mr. Pous bases his proposal on his assertion that the larger retirements are representative of one-time events and not ongoing activity. Even if that statement were valid, it misses the point of the net removal rate. The absolute amounts of either retirements or net removals that the Company experiences are not the specific direct drivers of the net removal rate. What matters in this analysis is the <u>ratio</u> of net removal to retirements. Based on the historical data specific to the Company, the likely expectation is that the net removal of interim retirements will be at least 25 percent.

Over the period of the past three Company Studies, the historical average net removal rates have increased. Using the ten-year band, for example, the net removal increased consistently from Study to Study from 23 percent in 2001, to 27 percent in 2005, to 29 percent in 2009, and to 34 percent in 2013. The Company's recommendations have generally followed the data, though in a generally conservative manner, which was the case again in this Study. Even without the recent data that Mr. Pous asserts is unrepresentative of future net removal, the proposed Company net removal rate is well supported. Using data through 2008, all the bands indicate 25 percent or greater net removal, and based on the trend of increasing net removal rate, the need to continue to move towards the historical indications of 25 percent or greater net removal is well supported.

Q Mr. Pous states that interim retirement net removal rates of zero to 7 percent were adopted in FPL's last case. Please comment.

A. This reference is presented completely out of context and is very misleading to the subject Gulf case. The referenced FPL net removal rates are not net removal rates to be applied to interim retirements like the Company's 25 percent; rather, they are the net removal rates <u>after</u> being adjusted for interim retirements. The Company's net removal rate after the 25 percent rate is applied to interim retirements is 4.5 percent. This "apples to apples" comparison is well within the range of FPL's adjusted rates and, contrary to Mr. Pous' misleading statement, it is very supportive of the Company's 25 percent net removal of interim retirements.

IV. MASS PROPERTY AVERAGE SERVICE LIFE

Q. Turning now to ASLs and curves, how many life curve combinations did you employ in your Study and how many does Mr. Pous contest?

A. I developed and used 29 life curve combinations for mass property accounts. Of those 29 life curve combinations, Mr. Pous accepted 18 and contested 11.

Q. What ASL and curve did Mr. Pous propose for Account 350.2 – Transmission Easements and Rights of Way?

A. Mr. Pous proposed an ASL and curve combination of 90R5 in place of the 65R5 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. Mr. Pous' proposed ASL is 30 years greater than the ASL approved by the Commission in the last Company case. My recommendation reflects an increase in the ASL of 5 years over the level currently approved by the Commission. Mr. Pous does not note any change in conditions since the last Study. Such a severe change in ASL as proposed by Mr. Pous is not warranted from any changed conditions of this account.

As support for his proposed ASL for Account 350.2, Mr. Pous looks to the maximum life expectancy of the Transmission assets that are installed in the easements and rights of way. If, as Mr. Pous suggests, one should look to the maximum life expectancy of 90 years of transmission poles and conductors to gauge the reasonableness of the two alternatives, then my proposed ASL is far more reasonable. My proposal suggests a maximum life for Account 350.2 of 92 years. Mr. Pous' proposal for Account 350.2 indicates a maximum life of 122 years.

Q. What ASL and curve did Mr. Pous propose for Account 353 – Transmission Station Equipment?

A. Mr. Pous proposed an ASL and curve combination of 48L0 in place of the 45S0 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were analyzed using the actuarial method. The observed data in this Study was lower than it was in the prior Study, which indicates a lower ASL. The observed curve from the 16-year band confirms that the indicated life is less than it was in the past. An increase in ASL from the ASL approved in the last case by the Commission (Mr. Pous' proposal) is the opposite direction that is expected when the current observed data is lower than the prior Study. Given the lower observed data, coupled with the uncertainties of fitting a curve to observed data, a reasonable conclusion would be keep the ASL flat at this time, particularly when the ASL of 45 years is within an industry range.

I also do not agree with the L0 curve proposed by Mr. Pous. In combination with a 45 or 48 year ASL, a L0 curve is unsuitable for depreciation purposes because the resulting maximum life expectancy of the investment is unreasonably long, greater than 180 years and 192 years for the 45L0 and 48L0, respectively. The L0 curve is the lowest mode curve (maximum retirement dispersion) in the typical group of Iowa-type curves used for depreciation. The maximum life expectancy resulting from the 48L0 curve is unreasonable and should have caused Mr. Pous to reconsider the curve he was proposing for this account. The maximum life expectancy of the Company's 45S0 is a more reasonable 90 years.

Mr. Pous' presentation of the life chart for this account is also a problem. The chart in his Exhibit JP-3 for this account only goes to 65 years and to 30 percent surviving. It is standard industry practice to plot all the observed data in the band and all or, at least, most of the fitted curves and not chop off a large part of the information. While the "tail" of the observed data (few retirements, few exposures) should be typically given little weight in the analysis compared to the region of the curve where the highest number of retirements occur, it is important to see all the data and fitted curves for a full analysis. Mr. Pous did not adhere to depreciation best practices.

Q. What ASL and curve did Mr. Pous propose for Account 356 – Transmission Overhead Conductors and Devices?

A. Mr. Pous proposed an ASL and curve combination of 53R0.5 in place of the 50R1.5 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were also analyzed using the actuarial method. The observed data in this Study was lower than it was in the prior Study, which indicates a lower ASL. The observed curve from the 21-year band confirms that the indicated life is less than it was in the past. An increase in ASL from the ASL approved in the last case (Mr. Pous' proposal) by the Commission is the opposite direction from what is expected when the current observed data is lower than the prior Study. My recommended 50R1.5 life curve combination fits the relevant portion of the observed curve where the largest number of retirements occurs reasonably well. Given the lower observed data, coupled with the uncertainties of fitting a curve to observed data, it is reasonable to keep the ASL flat at this time, particularly when the ASL of 50 years is within an industry range. I also note that the Company recommended ASL of 50 years is within one year of the average of the lives adopted in the recent FPL and Progress Energy Florida, now Duke Energy Florida (DEF), cases.

I also do not agree with the R0.5 curve proposed by Mr. Pous. It is a dramatic change from the R2 curve approved in the last Gulf case. In combination with Mr. Pous' proposed ASL of 53 years, its resulting maximum life expectancy of the investment is unreasonably long, greater than 105 years. My recommended R1.5 curve moves in the direction of the general indications from the data. I also note that the R1.5 curve was adopted by this Commission in both of the most recent FPL and DEF cases.

As was the case for Account 353, Mr. Pous' presentation of the life charts for this account is also a problem. The two charts in his Exhibit JP-4 and JP-5 for this account only go to 60 years and only to 30 percent and 40 percent surviving. As noted, it is standard industry practice to plot all the observed data in the band and all or, at least, most of the fitted curves and not chop off a large part of the information. Regardless of the portion of the observed data that is given the most weight in the analysis, it is important to see all the data and fitted curves for a full analysis. Mr. Pous did not adhere to depreciation best practices.

Q. What ASL and curve did Mr. Pous propose for Account 364 – Distribution Poles and Fixtures?

A. Mr. Pous proposed an ASL and curve combination of 34L0 in place of the 32L0 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were analyzed using the SPR method. The best fitting curves were indicated to be the lower mode curves. There is not a significant difference between the indicated fits of several lower mode curves such as L0-L1, S-.5-S0.5, and R0.5-R1.5. There is not statistical data that would limit the curve selection to a single curve for the data of this account. For the 20-year balance band, for instance, the maximum indicated life is 32 years for the L0 curve, while the indicated lives of the eight other reasonable curves to consider range from 27 years to 30 years. For life analysis, the longer bands are given the most weight as they reflect a long term view of life. Based on the historical date of the longer bands, the indicated life is approximately 30 years. The shorter 5 and 10 year bands are given less weight than the longer bands in the life analysis because they represent a shorter historical time frame. The average indicated life of the shorter 5 and 10 year bands is nevertheless less than 33 years. Based on the good support from the historical data, I concluded that the 32L0 life curve combination was the best result.

Mr. Pous based his conclusion of a 34L0 life curve combination on a near equal weighting of the longer bands and the shorter bands, mostly relying solely on the L0 curve with some weight to the R0.5 curve because of its closeness of fit. As noted, several other curves with lower indicated lives are essentially as good a fit as these two curves. Notwithstanding the weakness of relying on just the L0 and R0.5 curves used by Mr. Pous, the median indicated lives of those curves across all four balance bands is 32 years, which support the life I recommended.

The reasonableness of my recommended life is also supported by the most recent first in first out (FIFO) age of retirements, which is an indicator of life that is given some consideration in a life analysis, though not nearly as much as the SPR results. The FIFO age of the retirements is 28 years.

Q. What ASL and curve did Mr. Pous propose for Account 365 – Distribution Overhead Conductors and Devices?

A. Mr. Pous proposed an ASL and curve combination of 42R1 in place of the 40R1 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. Rather than rely on just one or two best fitting curves, an appropriate broader view of similar best fitting curves indicates a life of approximately 40 years. The trend in indicated lives since the last Study was an increase of one year. My recommended ASL in this case is 2 years greater than the ASL approved by the Commission in the last Company case. If Mr. Pous' proposal was adopted, the increase in ASL since the prior adopted ASL would be 4 years, well above the increase indicated by the historical data.

The reasonableness of my recommended life is supported by the most recent FIFO age of retirements of 33 years. I also note that the life proposed by Mr. Pous is greater than the ASL adopted by this Commission in the most recent FPL and DEF cases.

Q. What ASL and curve did Mr. Pous propose for Account 367 – Distribution Underground Conductors and Devices?

A. Mr. Pous proposed an ASL and curve combination of 39R2 in place of the 34S2 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were also analyzed using the SPR method. Middle mode curves were generally somewhat preferred as the best fitting curves in prior Studies. In the most recent Study, regardless of the indicated preference, essentially all the curves would be considered to be a good fit. In response to the general indications of best fits, I moved to a lower mode curve.

Mr. Pous characterized his proposal as a gradual movement towards life indications. Mr. Pous proposed ASL is 7 years greater than the ASL adopted by the Commission in the prior Gulf case. The historical data indicates an increase in life of less than 1 year to less than 2 years. An increase in ASL of 7 years can hardly be considered gradual, especially in light of the fact that the life indications increased by less than 2 years since the last Study.

In support of Mr. Pous' proposed R2 curve, he notes that the FPL and DEF both proposed a R2 curve. In those studies, the life pairing to the R2 curve were ASLs of 35 years, in both cases, an increase of 1 year from their existing ASL. The reasonableness of my recommended life is also supported by the most recent FIFO age of retirements of only 29 years. Overall, the data supports my recommended 34S2 and indicates that Mr. Pous' proposal is extreme.

Q. What ASL and curve did Mr. Pous propose for Account 368 – Distribution line Transformers and Devices?

A. Mr. Pous' proposed an ASL and curve combination of 34R0.5 in place of the 32S0 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were also analyzed using the SPR method. As both Mr. Pous and I agree, a lower mode curve is preferred by the historical data. The fit measures of several lower mode curves are not significantly different. The curve selected by me, S0, is in fact has the sixth best fit indicator and is not significantly different from the curves referenced by Mr. Pous as best fitting. The pattern of the best fitting curves has not changed in at least 10 years. The S0 curve has been approved in the Company's previous Studies.

From the historical data, the indicated life of the S0 curve from the 30-year band was 30 years. The longer balance bands are given predominate weight in the life analysis because they reflect the long time average life. The shorter bands are also considered and the indicated life of the S0 curve from the shorter bands was approximately 31 years. The median life indication of the three lowest mode curves of each curve type from the longest bands was approximately 31 years. The life indications have been slowly increasing. Since the last Study, life indications have increased by less than 1 year to less than 2 years, depending on the curve and the band. The ASL I recommended is an increase of 2 years from the ASL adopted by the Commission in the prior case.

In his testimony, Mr. Pous states that an ASL increase of 2 years is recommended. In fact, Mr. Pous is proposing an increase of 4 years for the ASL. The ASL I am recommending is an increase of 2 years.

The reasonableness of my recommended life is also supported by the most recent FIFO age of retirements of 28 years. The curves proposed and adopted in the most recent FPL and DEF cases were middle mode curves. Further, in those two cases, the adopted ASLs were both less than the ASL proposed by Mr. Pous in this proceeding.

Q. What ASL and curve did Mr. Pous propose for Account 369.1 – Distribution Overhead Services?

A. Mr. Pous proposed an ASL and curve combination of 44R1 in place of the 40R1 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were also analyzed using the SPR method. As Mr. Pous noted, by strict mathematical ranking, the Company recommended 40R1 life curve combination had the fourth best fitting index. Looking at the longer balance bands, the most important bands for the life analysis, there was not a significant difference in the fit index between the so called best fit and the fourth best fit. That is not surprising, given that there are 26 curves being applied and the industry-accepted fact that the SPR goodness-of-fit index is a useful tool but it is not a precise indicator. There was, in fact, not a significant difference in the fit index among the 12 best fitting curves for this account. Mr. Pous has fallen into an overly simple, narrow mathematically-driven procedure. The median life indications of the four lower mode curves of each curve type in the longer bands are 40 years. While there are life indications greater than 40 years, there are also life indications of less than 40 years, all reasonably supported. The reasonableness of the ASL I recommended is also supported by the most recent FIFO age of retirements of 35 years.

The ASL I recommended is a significant increase of 5 years from the 35-year ASL approved in the last Gulf case. Mr. Pous' proposal is for a 9 year increase from the current ASL. Considering that the indicated lives from the historical data were only 2 to 5 years across all curves and bands since the last Study, the proposed 9-year ASL increase by Mr. Pous is very dramatic. As support for his proposed ASL, Mr. Pous refers to the recent FPL case where FPL proposed an ASL increase of 12 years. For this same account, DEF proposed a decrease of 2 years in the ASL to 34 years. The ASL I recommended and its increase from the last Study is very nearly the midpoints of these two recent Florida cases, while those of Mr. Pous are towards the high side of the range. To the extent reliance is given to other cases of this Commission, the ASL I recommended for Account 369.1 is more consistent with the two cases than Mr. Pous' proposed ASL.

Q. What ASL and curve did Mr. Pous propose for Account 370 – Distribution Meters, AMI?

A. Mr. Pous proposed an ASL and curve combination of 20R1 in place of the 15R1 recommended by me on behalf of the Company.

Q. Do you agree with the Mr. Pous' proposal?

A. No, I do not. AMI meters are recent technology and the Company's experience with this equipment is not adequate at this time to draw a life conclusion using typical life methods. The existing AMI meter rate was derived from a 15-year ASL that was adopted by this Commission in the Company's last case. There have not been known changes since the Company's last case that would suggest a change to the life should be made. The ASL of 15 years is within the range of industry indications.

The ASL proposed by Mr. Pous is at the long end of the industry range. In support of his proposed ASL, Mr. Pous refers to the ASL proposed by FPL in its last case. In that case, FPL also proposed a net removal of 55 percent. Under that combination of ASL and net removal, the indicated depreciation rate is greater than the depreciation rate I recommended in this case. Using the adopted net removal of 30 percent, the resulting indicated depreciation rate from that FPL case is significantly greater than the implied depreciation rate being proposed for Gulf by Mr. Pous.

It should be noted that in the last DEF case, DEF proposed and the Commission adopted an ASL of 18 years for a composite meters account, one that includes both AMI meters and legacy electromechanical meters. A reasonable assumption is that an ASL of greater than 18 years applies to the legacy meters, implying an ASL of less than 18 years for the AMI meters. Also, in the DEF case, the Commission adopted a net removal of 8 percent, which in combination with the adopted ASL, implies a depreciation rate that is significantly greater than the depreciation rate implied by Mr. Pous' proposal.

If the implied depreciation rates of the other Florida utilities are used as a test of reasonableness, my recommended ASL is more reasonable than the ASL proposed by Mr. Pous.

Q. What ASL and curve did Mr. Pous propose for Account 373 – Distribution Street Lighting?

A. Mr. Pous proposed an ASL and curve combination of 24L0.5 in place of the 22L1 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were analyzed using the SPR method. The L1 curve that I recommended was the curve adopted by the Commission in the last case. By strict ranking, the Company recommended L1 curve had the seventh best fitting index. There was, however, only a small difference in the fit index from the so called best fit R0.5 through all the low mode curves across all bands. The fit index of essentially all the lower mode curves are not significantly different from each other in this case. Mr. Pous has again fallen into an overly simple, narrow mathematically-driven procedure in his analysis of curves. Best practices are to consider all curves that have similar fit indexes, and not simply the so called best fitting curve. The L1 curve is well supported by a proper analysis of the SPR data.

As noted, the most important bands for the life analysis are the longer bands. In the longer bands, the indicated life for the L1 curve is approximately 20 years. The median indicated life of the group of lower mode curves is in the range of 19 years to 22 years. In the shortest band, the indicated life of the L1 curve is less than 24 years and 22 years for the median lower mode S and R curves. As noted, the shortest band is generally given little weight in the analysis of the ASL, which is long term.

In his testimony for this account, Mr. Pous referred to the "most recent band" indicating an ASL. The band he is referring to is the shortest band as it has the fewest number of balances to match to. To refer to it as the most recent band is misleading.

Later in his testimony for this account, Mr. Pous asserts that "Again, the Commission will likely need to significantly increase the ASL in future depreciation studies." This is a misleading statement. If the life indications in the next Study result in the same SPR results as the current Study, there would be no cause to raise the ASL, much less significantly increase it. Whether the ASL needs to be changed in the next Study, up or down, depends on the historical information and analysis of the next Study. To confirm or change the current ASL is a reason why this Commission and the Company follow best practices in having periodic Studies.

Finally, Mr. Pous notes that FPL in its last Study proposed a large ASL increase for this account. Mr. Pous choose not to note that DEF in its last Study proposed, and this Commission adopted, the L1.5 curve and a smaller 3-year ASL increase to 20 years for this account, which is consistent with the 22L1 life and curve combination that I recommend.

Q. What ASL and curve did Mr. Pous propose for Account 390 – General Structures and Improvements?

A. Mr. Pous proposed an ASL and curve combination of 50S0.5 in place of the 45S1.5 recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The ASL and curve of this account were analyzed using the actuarial method. As was the case for Accounts 353 and 356, Mr. Pous' presentation of the life charts for this account is also a problem. The chart in his Exhibit JP-6 for this account only goes to 50 years and only to 40 percent surviving. As noted, it is standard industry practice to plot all the observed data in the band and all or, at least, most of the fitted curves and not chop off a large part of the information. Regardless of the portion of the observed data that is given the most weight in the analysis, it is important to see all the data and fitted curves for a full analysis. Mr. Pous did not adhere to depreciation best practices.

For this account, Mr. Pous stopped his chart one period before the observed data drops by 35 percentage points, because of a $1,200,000 retirement. By his choice of the chart he shows, Mr. Pous has given no consideration to this data point. While Mr. Pous may conclude to give more weight to some data points and less to others, it is incumbent on Mr. Pous to give some consideration of that large retirement in his life and curve analysis. It certainly must be presented in his chart. Any consideration of that data point might have caused Mr. Pous to decrease the ASL and to increase the mode of his curve in order to move his fit somewhat towards that low data point to narrow his fit gap of more than 30 percentage points. Besides being the life and curve adopted in the last several Company cases, the 45S1.5 life curve combination I recommended recognizes that large though real drop in the observed data. At the same time, it maintains a reasonably close fit to the middle portion of the observed data points, which should get the most weight (but not 100% of the weight).

V. MASS PROPERTY NET REMOVAL

Q. Turning now to the final subject, how many net removal rates did you employ in your Study and how many of those rates were contested by Mr. Pous?

A. I developed and used 29 net removal rates for mass property accounts. Out of those 29 mass property net removal rates, Mr. Pous accepted 24 and contested five.

Q. What net removal did Mr. Pous propose for Account 356 – Transmission Overhead Conductors and Devices?

A. Mr. Pous proposed a net removal of 20 percent in place of the 30 percent recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The Company experience is 25 percent net removal in the shorter 10-year band and 40 percent in the 15-year and 20-year bands. The data of this Study is largely consistent with the indications from the previous Study. Mr. Pous asserts that economies of scale will cause lower net removal. To the extent economies of scale might exist and influence net removal, they are appropriately captured in the analysis of historical net removal data, as the net removal indications are weighted by the level of retirements. A specific downward adjustment in net removal for economies of scale is neither necessary nor supported by specific data.

Mr. Pous points to the 2012 data as an example of economies of scale. As stated in the Company's response to a Staff data request, 2012 data included fourth quarter estimates. As shown in the Company's response to a second data request by the Staff, the actual net removal of 2012 is 19 percent, greatly in excess of the 8.4 percent net removal based on estimated data that was referred to by Mr. Pous. When the 2012 actual data is substituted, the 10-year band indicates 28 percent net removal, nearly equal to the net removal I recommended.

The data for Account 356 well supports the continuation of the same 30 percent net removal adopted in the previous case. In addition, across all of the Transmission function, the Company's net removal experience is greater than 40 percent, while its recommended net removal rates result in a composite Transmission net removal of 26 percent. The fact that the composite rate from the recommended net removal is significantly less than the Company experience supports the overall reasonableness of all the Transmission net removal that I recommended, including Account 356.

Q. What net removal did Mr. Pous propose for Account 362 – Distribution Station Equipment?

A. Mr. Pous proposed a net removal of 5 percent in place of the 8 percent recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The Company experience is 10 percent or more net removal in all the bands, shorter and longer. Also, the net removal is greater in the current Study than in the previous Study. The small increase from the adopted net removal of the last case to 8 percent is well supported by analysis of Company experience.

Mr. Pous notes that salvage is only shown in the most recent 7 years. The net removal during the period when salvage is recorded is more than 10 percent, which supports the net removal of 8 percent that I recommended. Further, if the recent salvage experience is assumed for the periods before salvage is shown, the net removal is greater than or equal to 8 percent for all bands.

Mr. Pous also notes that the price of scrap copper will result in positive net salvage in some circumstances. Mr. Pous offers no specific data in this regard. Further, the cost of scrap copper has been relatively high for greater than 7 years and is, therefore, likely adequately reflected in the Company data. Finally, Mr. Pous speculates that short historical periods may not be representative of all types of equipment and their net removal. My analysis, like those by other seasoned experts, does not rely solely on a particular year or a very short band of net removal data. As noted, all bands show net removal indications of at least 8 percent.

While I did not rely on the experience of other Florida utilities in making the recommended 8 percent net removal, I note the net removal adopted by the Commission in the last FPL and DEF cases were both 10 percent for Account 362.

Q. What net removal did Mr. Pous propose for Account 368 – Distribution Line Transformers?

A. Mr. Pous proposed a net removal of 20 percent in place of the 24 percent recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The Company experience is 25 percent to 26 percent net removal in the 10-year to 20-year bands. Since the last Study, there were increases in the indicated historical net removal. The modest increase from the adopted net removal of the last case to 24 percent recommended in this case is well supported by analysis of Company experience and is within the industry range.

Mr. Pous suggests that net removal will be less in the future due to relatively more retirements of lower net removal pad-mounted transformers. He based his suggestion on the data of two particular years. In his analysis in the previous account, he warns against drawing conclusions from a small number of years, which he is doing for this account. In Account 368, he is relying heavily on too many assumptions and too little data. The frequent periodic Studies made by the Company will quickly reveal a trend of decreased net removal for this account if one occurs. An increase in the existing net removal of this account is appropriate.

Q. What net removal did Mr. Pous propose for Account 390 – General Structures and Improvements?

A. Mr. Pous proposed a net removal of -10 percent (positive net salvage) in place of the net removal of 5 percent (negative net salvage) recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The Company experience is net removal of 9 percent to 10 percent in the 10-year to 20-year bands. Since the last Study, there were small increases in indicated net removal. While the net removal indications are not conclusive because of limited retirement data, there were some $10,000,000 of retirements during the analysis period, more than enough that the indicated net removal results from the data require consideration in the analysis. In my experience, the utility industry most often uses for this account a net removal of zero to five percent.

Mr. Pous bases his proposed net removal on his assumption that the Company's office and warehouses will have significant levels of positive net salvage at their retirement. Mr. Pous does not offer data to support his assumption. As Mr. Pous notes, various building components incur net removal when they are replaced. It appears that Mr. Pous is overestimating the value of general purpose buildings at the end of their economic life and understating the extent of special purpose buildings, building components, and improvements.

Q. What net removal did Mr. Pous propose for Account 392.3 – General Heavy Trucks?

A. Mr. Pous proposed a net removal of -15 percent (positive net salvage) in place of the net removal of -13 percent (positive net salvage) recommended by me on behalf of the Company.

Q. Do you agree with Mr. Pous' proposal?

A. No, I do not. The Company experience is net removal of -13 percent in the 5-year and 10-year bands. These shorter bands are more relevant to the analysis than the longer bands of 15 years and 20 years, because the longer bands contain old data that exceeds the ASL of Heavy Trucks, which makes them of little or no relevance to the analysis of existing investment.

Mr. Pous implies that the 2010 data, which has the lowest net salvage percentage, is unrepresentative. No evidence was presented in support of that. Even if 2010 data is completely excluded from the 10-year band, and there is no justification for that exclusion, the indicated net removal is -13.3 percent, which is supportive of the Company recommended net removal. I note that in 7 of the last 10 years of the Company data, positive net salvage is less than the positive net salvage proposed by Mr. Pous.

Q. Please summarize your rebuttal testimony.

A. Gulf requested and received from American Appraisal an independent assessment of Gulf's appropriate depreciation rates. Gulf did not attempt to influence the results of our analysis, and Gulf submitted our Study without changing any recommended depreciation rates or substantive elements used to develop rates.

Despite the length of Mr. Pous' direct testimony and my rebuttal testimony, there are more instances where Mr. Pous accepts my conclusions than where he contests them. As to the contested issues, I have given the basis for my judgments and explained why my considerations and conclusions are more reasonable than those offered by Mr. Pous.

The Study performed on behalf of Gulf is consistent with standard industry practice, and it is consistent with prior Studies American Appraisal has presented on behalf of Gulf and that have been relied upon by this Commission. Our Study is well documented and thoroughly defended. It should be relied upon by the Commission and used to establish Gulf's rates.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

RICHARD J. MCMILLAN

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Richard J. McMillan
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Richard McMillan. My business address is One Energy Place, Pensacola Florida, 32520 and I am the Forecasting, Budgeting and Corporate Performance Manager for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to demonstrate why the Commission should reject Office of Public Counsel (OPC) Witness Garrett's proposed disallowance of aircraft expenses and his proposed productivity adjustment to Gulf's test year labor expense. I also show that Mr. Garrett's proposed adjustment to capitalized incentive compensation is calculated incorrectly and that in supporting an annualized revenue adjustment he has inaccurately characterized Gulf's test year labor and other expense budgets.

Q. Are you sponsoring any rebuttal exhibits?
A. Yes, I am sponsoring Exhibit RJM-2, Schedules 1 and 2. This exhibit was prepared under my direction and control and the information contained therein is true and correct to the best of my knowledge and belief.

I. AIRCRAFT EXPENSE

Q. Does Gulf own or lease any aircraft?
A. No. However, as a subsidiary of the Southern Company, Gulf has the ability to use corporate aircraft operated by Southern Company Services when face-to-face meetings are required and air travel is the most efficient mode of transportation. Gulf employees can utilize System Air for business travel when an authorized officer initiates the flight and documents the business purpose. Gulf is charged an equivalent commercial airfare for flights by its employees on the system aircraft ("System Air"). Gulf also receives an allocated share of System Air costs that are not covered by the per flight charges.

Q. What is the test year budget for Gulf's use of the system aircraft?
A. The test year budget for use of System Air is $2,244,000.

Q. Should the Commission accept Mr. Garrett's recommendation to disallow Gulf's entire System Air budget?

A. No. Gulf's System Air cost is a reasonable and necessary business expense that benefits customers by improving the productivity and efficiency of Gulf employees whose duties require business related travel. Mr. Garrett's proposal to disallow the total System Air budgeted expense also fails to make an offsetting allowance for other costs that Gulf would incur in the absence of access to System Air, including the cost of alternative travel by commercial air or rented vehicles, parking and baggage check fees, along with additional expenses for meals and lodging when travel times are extended.

Q. How does the use of corporate aircraft improve the productivity of Gulf employees whose duties involve business travel?

A. One of the largest savings is the reduction in non-productive time of employees due to commercial scheduling limitations and airport security screening requirements. Without access to the corporate aircraft, Gulf's employees would be unable to attend many important meetings due to the limited commercial air flights available to and from Pensacola. For example, Gulf employees are frequently called on to travel to Birmingham or Tallahassee, yet there are currently no direct flights from Pensacola to either of these cities. Where flights to important destinations are available, flight schedules may limit or preclude attendance at early morning or late afternoon meetings without requiring overnight lodging associated with either day ahead travel or next day returns. Commercial flight schedules present a particular problem when meetings in different cities are scheduled on the same day or on successive days. The use of system aircraft also avoids the loss of employee time associated with delayed or cancelled commercial flights.

Q. What additional adjustments would be required if the Commission were to disallow all or a portion of Gulf's System Air aircraft costs?

A. As noted earlier, if the costs of system aircraft are excluded, the Commission should at a minimum provide an offset for the added cost of commercial airfare, rental cars, meals, lodging and other travel related costs which would be incurred as a less efficient replacement for the budgeted use of System Air. Gulf estimates that the commercial airfare alone would be approximately $500,000.

Q. Is Gulf's System Air cost a reasonable and prudent business expense?

A. Absolutely. It is essential that Gulf employees be able to represent Gulf and its customers at required company, system, industry and regulatory meetings. The inability to call on System Air for necessary business travel would have a negative impact on employee productivity or could preclude attendance at some necessary meetings. Time spent by an employee on inefficient travel is time that is not available to devote to other necessary duties. Gulf's corporate aircraft expense is a reasonable and necessary cost of doing business, and no adjustment is necessary or appropriate.

II. PRODUCTIVITY ADJUSTMENT

Q. Please describe Mr. Garrett's proposed productivity adjustment to test year payroll expense.

A. Mr. Garrett claims that it is inappropriate to include budgeted pay increases for 2013 and 2014 in the Company's test year expenses without making an offsetting reduction for productivity gains. He proposes to reduce Gulf's test year payroll and payroll tax expense by a total of $2,374,000 based on his recommendation that the Commission apply a 1.7 percent per year productivity adjustment to the Company's 2013 and 2014 payroll expense. The 1.7 percent figure is the average productivity improvement in the manufacturing sector from 2007 to 2012 as reported by the Bureau of Labor Statistics (BLS) in its September 5, 2013 News Release on Productivity and Costs.

Q. Do you agree with Mr. Garrett's recommendation?

A. No. His analysis is seriously flawed. The most obvious concern is his use of historical information from the manufacturing sector as a basis to estimate expected future productivity improvements in the electric utility industry. The manufacturing sector consists of 21 subsectors comprising companies "engaged in the mechanical, physical, or chemical transformation of materials, substances or components into new products." The manufacturing sector does *not* include electric utilities, which are instead included in the service-providing industries supersector.

Q. What is the most recent BLS data for productivity in the electric utility industry?

A. The most recent published data for specific industries, including the electric utility industry, is for 2011. The data for the electric utility industry is summarized in the BLS May 29, 2013 News Release on Productivity and Costs in selected service-providing and mining industries, a copy of which is attached as Schedule 1 of Exhibit RJM-2. As shown in this report, the power generation and supply industry had *negative* 5.6 percent change in productivity from 2010 to 2011. The more detailed historical industry-specific productivity statistics from the BLS show that since 2007, the electric utility industry showed improved productivity only in 2010. Industry productivity figures were negative in 2007, 2008, 2009 and 2011. See Schedule 2 of Exhibit RJM-2.

Q. Based on this industry specific data, would it be appropriate for the Commission to make a negative productivity adjustment (that is, an increase) to labor costs for 2013 and 2014?

A. No, such an adjustment would be just as inappropriate as the positive adjustment proposed by Mr. Garrett. The BLS productivity data represent historical information on the relationship between real output and the labor time involved in its production. Historical information regarding productivity gains or losses is not necessarily indicative of productivity gains or losses in the future. It also assumes without analysis that industry-wide data is representative of each and every company in the industry.

Q. Is there any other reason to reject a productivity adjustment in this case?

A. Yes. For industries in the service sector, real output is measured by sales revenues. In the electric utility industry, sales revenues depend in large part on the demands placed on the system by customers hour-by-hour, yet the number of man-hours to operate the electric system does not vary in proportion to the capacity factor at which generating units are called on to operate. All other things being equal, a decline in sales revenues in a given year will be reflected as a decline in productivity. This is true whether the sales revenue decline is the result of a depressed economy, changes in weather, decreases in fuel prices, increased conservation, or any other factor. Oddly, because an increase in revenues translates to increased productivity, a utility's calculated productivity is "improved" when increasing fuel prices are reflected in fuel clause charges or when the Commission grants a base rate increase.

Given the interplay of all of these factors, a productivity adjustment is particularly inappropriate in an electric utility rate case absent specific identifiable and quantifiable labor productivity gains. Mr. Garrett identifies no such gains.

Q. Are there any other reasons to reject Mr. Garrett's recommendation?

A. Yes, there are several. First, Mr. Garrett suggests that Gulf has selectively increased payroll expense without taking into account offsetting cost reductions that might flow from improvements in productivity. To the contrary, Gulf used a rigorous budget process to develop a test year budget which projects all categories of revenues and expenses. Any expected productivity improvements are already reflected in the Company's O&M budget. It is interesting to note that in the Utah case that Mr. Garrett cites as support for a productivity adjustment, the Commission elected to make "no further adjustment for productivity beyond what is incorporated in the Company's projections." See Garrett testimony, page 43, lines 22-24.

Second, Mr. Garrett provides one-sided examples to support his claim that budgeted pay increases could be more than offset by other events. He cites potential workforce reductions as an event that could have a large impact on payroll expense. However, as Gulf stated in response to OPC's Interrogatory No. 8 regarding workforce reductions during the next three years, Gulf has no plans to reduce the number of employees through voluntary or involuntary workforce reduction programs. Mr. Garrett also cites a situation in which a higher-paid retiring employee is replaced by a lower-paid new hire, thus reducing payroll expense. However, he does not consider the loss in productivity from replacing an experienced employee with one – or perhaps even two – inexperienced personnel. And Mr. Garrett states that changes in a company's capitalization percentage can reduce payroll expense levels even with no reduction in overall payroll costs. He fails to point out that the converse is equally true – changes in the capitalization percentage can increase payroll expense even though overall payroll costs remain unchanged.

Q. Should the Commission give any weight to Mr. Garrett's assertion that two other state commissions have made productivity adjustments?

A. No. Mr. Garrett cites decisions from California and New York, but he does not cite the Florida decisions that have rejected various proposals for taking productivity into account.

As early as 1975, the Commission rejected OPC's proposal in a Gulf rate case to offset a projected wage increase with a revenue and/or productivity adjustment, saying "the record is devoid with respect to any tool or device by which to measure with any degree of precision such factors as increased productivity that may be expected to be realized by a public utility at sometime in the future." In re: Petition of Gulf Power Company to increase its rates and charges, Docket No. 74437-EU, Order No. 6650 (May 7, 1975) at page 12. Nothing has changed in the current rate case.

The Commission in 2010 also rejected proposals by OPC in the Progress Energy rate case, and by another intervenor in the Florida Power & Light rate case, to reduce those companies' test year O&M expenses to reflect increased productivity. In re: Petition for increase in rates by Progress Energy Florida, Inc., Docket No. 090079-EI, Order No. PSC-10-0131-FOF-EI (March 5, 2010) at pages 103-105; In re: Petition for increase in rates by Florida Power & Light Company, Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI (March 17, 2010) at pages 144-145.

And in a 1988 Southern Bell case, the Commission concluded that "there is nothing in this record that provides a way to measure efficiency or to establish an 'industry norm' for labor, capital and total factor productivity. We do not believe that productivity gains can be isolated at this time." In re: Petitions of Southern Bell Telephone and Telegraph Company for Rate Stabilization and Other Relief, Docket No. 880069-TL, Order No. 20162, 1988 Fla. PUC LEXIS 1571 at *14 (October 13, 1988).

Although Mr. Garrett's proposal differs in its details from the productivity adjustments that the Commission has previously considered and rejected, it suffers from the same fundamental flaw – it is not supported by any reliable estimate of productivity increases that might occur.

Q. Did you identify any inconsistencies between Mr. Garrett's productivity adjustment and his other proposed adjustments?

A. Yes. Mr. Garrett calculates his productivity adjustment based on total O&M payroll. Yet in other issues, he recommends disallowing over $12 million of incentive-based compensation that is included in that payroll. Other witnesses show why Mr. Garrett's adjustments to incentive compensation should be rejected – my point is that he is internally inconsistent and double-counts his proposed expense adjustments.

III. OTHER ISSUES

Capitalized Incentive Compensation

Q. Mr. Garrett asserts that if the Commission accepts his proposal to disallow short-term incentive costs related to financial performance, then it should also make a corresponding $2.375 million rate base adjustment for capitalized incentive compensation. Is there a problem with his assertion?

A. Yes. Other Gulf witnesses demonstrate that it is inappropriate to make any adjustment to incentive compensation, either expense or capital. Even if the Commission adopted Mr. Garrett's view, the amount of his proposed rate base adjustment is significantly overstated. As I explain below, less than 20 percent of the $2.375 million he calculates is actually included in the requested 2014 jurisdictional adjusted rate base.

Q. Please explain why Mr. Garrett's proposed adjustment is overstated.

A. There are two major problems with Mr. Garrett's calculation. The first is his implicit assumption that 100 percent of the capitalized labor expense budgeted for 2014 is included in the test year average rate base. Labor is paid and capitalized throughout the year. Therefore on a test year average basis, only about 50 percent of capitalized labor would be included in the test year rate base.

The second problem is Mr. Garrett's failure to consider that over half of the 2014 projects that include capitalized labor are removed from adjusted rate base through the ratemaking adjustments to exclude interest-bearing construction work in progress (CWIP) and clause-related investments. Based on the projects included in Gulf's 2014 capital budget, I estimate that approximately 65 percent of the total 2014 capital expenditures have already been removed from rate base through these adjustments. This leaves only 35 percent of the capital costs – and approximately the same percentage of capitalized labor – in the test year jurisdictional adjusted rate base.

Q. What is the combined effect of these two problems?

A. Because only about 50 percent of capitalized labor costs are included in the unadjusted test year average rate base and only about 35 percent of those dollars remain after ratemaking adjustments, the capitalized labor included for ratemaking purposes is less than 20 percent (50 percent x 35 percent = 17.5 percent) of the total capitalized labor budget. Even if the Commission were to make an adjustment to disallow a portion of capitalized labor related to Gulf's short-term incentive plan, Mr. Garrett's adjustment is overstated by a factor of five.

Annualization of Expenses

Q. Is Mr. Garrett correct when, as support for his proposed revenue annualization adjustment, he states that Gulf has applied a test year end annualization to its payroll and other expense projections?

A. No. Gulf does not annualize costs in our budget. As discussed by Gulf Witness Ritenour and other witnesses, Gulf's Planning Units closely examine and analyze the activities necessary to accomplish their goals and responsibilities. The Planning Units then build their annual budgets month by month as necessary to meet those responsibilities. For example, labor merit increases are reflected in March (September for union employees) of each year and planned maintenance items for Production and the other Planning Units are budgeted in the months they will be incurred.

The labor budget is based on the overall labor complement that management has determined is necessary to meet Planning Unit goals. The needed employees are included in the budget for the full year (January through December), but their year-end labor costs are not annualized. Instead, Gulf's detailed monthly budgets include the result of annual merit increases beginning in the month when those increases take effect. The budgets also reflect appropriate increases in other months when individual salary adjustments related to promotions or earned progression are expected.

IV. CONCLUSION

Q. Please summarize your testimony.

A. The Commission should reject Mr. Garrett's proposals to disallow System Air expense and to make a productivity adjustment to labor expense. Gulf's cost for System Air is a reasonable and necessary business expense that minimizes the loss of productivity that would occur if Gulf's employees were forced to rely solely on travel by commercial air or rental vehicles. His proposed productivity adjustment is based on data that does not apply to the electric utility industry and is inconsistent with prior Commission decisions declining to make productivity adjustments.

Even if the Commission were to accept Mr. Garrett's proposal to disallow a portion of Gulf's short-term incentive compensation expense – a proposal which other Gulf witnesses show should be rejected – his corresponding rate base adjustment to capitalized incentive compensation is calculated incorrectly and overstated by a factor of five. Finally, in attempting to support an annualized revenue adjustment, Mr. Garrett has inaccurately characterized Gulf's test year labor and other expense budgets.

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

Exhibit

BLS NEWS RELEASE

BUREAU OF LABOR STATISTICS
U.S. DEPARTMENT OF LABOR

For release 10:00 a.m. (EDT) Wednesday, May 29, 2013 USDL-13-1041

Technical Information: (202) 691-5618 • dipsweb@bls.gov • www.bls.gov/lpc
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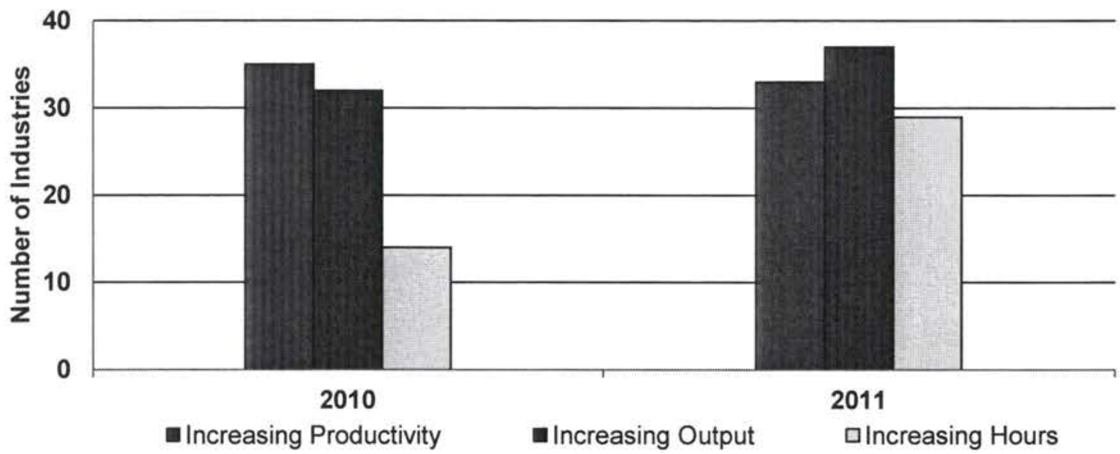
Docket No. 130140-EI
Witness: Richard J. McMillan
Exhibit No. ____ (RJM-2)
Schedule 1

PRODUCTIVITY AND COSTS BY INDUSTRY: SELECTED SERVICE-PROVIDING AND MINING INDUSTRIES, 2011

Labor productivity – defined as output per hour – rose in 63 percent of the 52 service-providing and mining industries studied in 2011, the U.S. Bureau of Labor Statistics reported today. This was down from 67 percent in 2010. **Unit labor costs**, which reflect the total labor costs required to produce a unit of output, declined in 35 percent of the industries in 2011, compared to 44 percent in 2010.

More industries recorded gains in output and in hours in 2011 than in the previous year. (See chart 1 and table 1.) Output rose in 37 of the 52 service-providing and mining industries studied in 2011, an increase from 32 industries in 2010. Hours rose in 29 of the industries in 2011 compared to 14 in 2010. Both output and hours rose in more industries in 2011 than in any year since 2006.

Chart 1. Number of service-providing and mining industries with increases in productivity, output, and hours, 2010 and 2011



Unit labor costs fell in 17 of 47 service-providing industries in 2011, down from 23 industries in 2010, but in only 1 of the 5 mining industries. Unit labor costs declined more frequently in industries where productivity rose, as productivity gains offset movements in hourly compensation. Almost 90 percent of the industries with declines in unit labor costs in 2011 posted gains in productivity.

Industry labor productivity measures are updated and revised as data become available. The latest productivity measures for service-providing and mining industries and industries in other sectors are available on the BLS Labor Productivity and Costs web site at http://www.bls.gov/lpc/iprprodydata.htm.

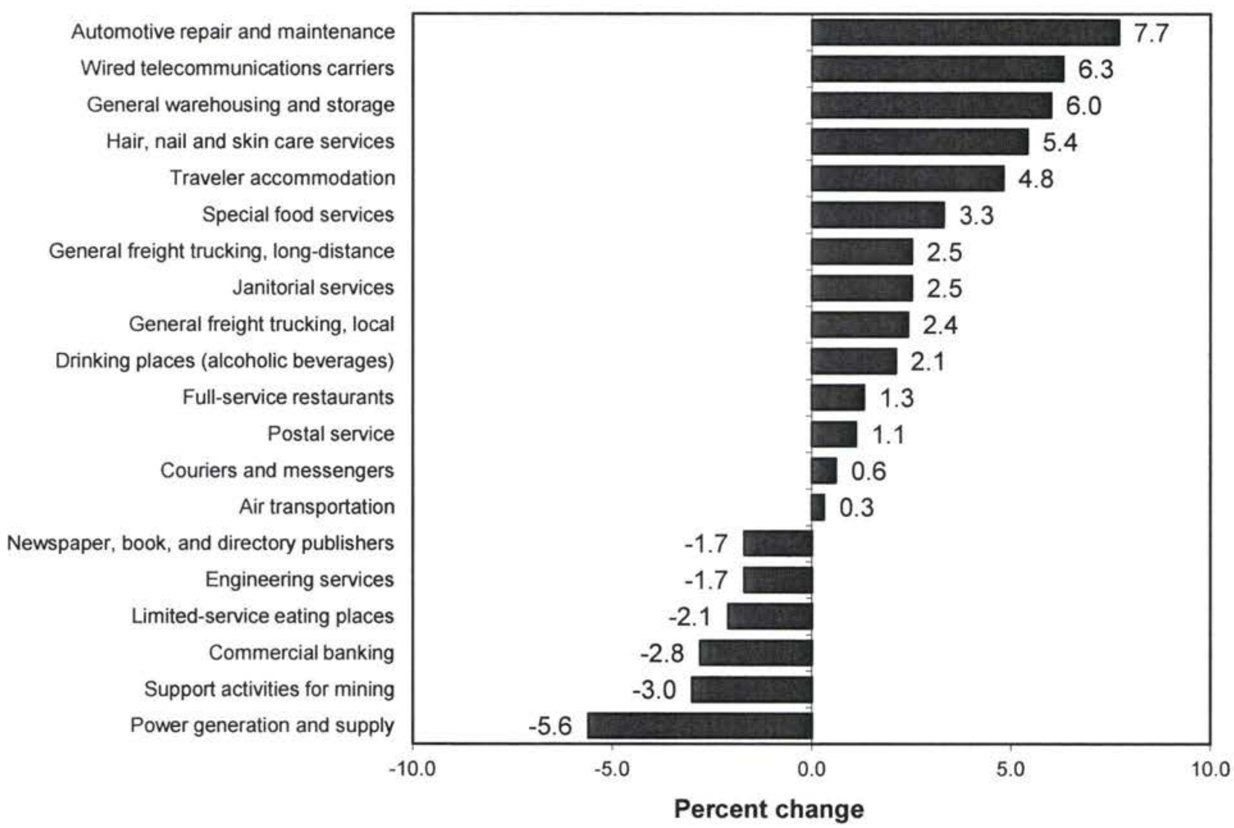
Service-Providing Industries: Output per hour increased in 2011 in 32 of the 47 industries studied. In most of these industries, productivity rose as output growth was accompanied by declines or more modest increases in hours. Several industries posted double-digit productivity gains as a result: wireless telecommunications carriers; passenger car rental; photography studios, portrait; and photofinishing.

In a few industries, productivity rose as declining output was met with even greater reductions in hours: postal service; couriers and messengers; video tape and disc rental; tax preparation services; drinking places (alcoholic beverages); reupholstery and furniture repair; and coin-operated laundries and drycleaners.

Mining Industries: Output per hour declined in four of the five detailed mining industries studied in 2011, as hours rose while output fell or grew more slowly. Only nonmetallic mineral mining and quarrying posted a productivity increase. The overall mining sector experienced a double-digit decline in productivity, as labor hours increased more than four times as much as output.

Chart 2 shows the 2011 percent change in productivity in the 20 largest service-providing and mining industries. Among these industries, automotive repair and maintenance recorded the largest productivity increase, as output growth was accompanied by a modest decrease in hours. Productivity fell the most in power generation and supply, where hours rose while output declined.

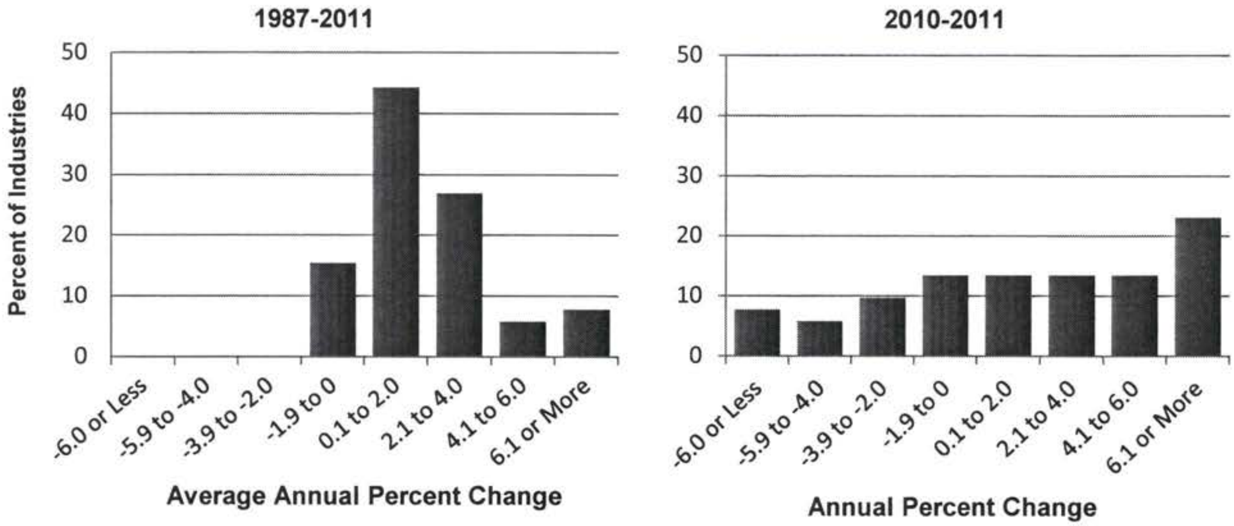
Chart 2. Percent change in output per hour in the largest (by employment) service-providing and mining industries, 2010-2011



Long-Term Trends

More industries posted productivity gains over the 1987-2011 period than in 2011. Chart 3 contrasts the distribution of productivity changes over the long term with those in the most recent year. Between 1987 and 2011, labor productivity increased in 85 percent of the detailed service-providing and mining industries, with over 70 percent of industries recording average annual productivity growth between 0.1 and 4.0 percent per year. In 2011, only 27 percent of industries recorded productivity growth in that range. Industry productivity performance in 2011 was more widely distributed, with 37 percent of industries posting productivity declines and 37 percent posting productivity gains of 4.1 percent or more.

Chart 3. Distribution of percent change in output per hour, 1987-2011 and 2010-2011



The measures in this news release incorporate data from the 2011 Service Annual Survey published by the Census Bureau, as well as the March 2013 annual benchmark revision of the BLS Current Employment Statistics (CES) survey. All of the measures for 2011 in this release are preliminary and subject to revision. The industries included in this release are classified according to the 2007 NAICS. While the rates of change reported in this news release are rounded to one decimal place, all industry productivity percent changes are calculated using index numbers rounded to three decimal places.

Year-to-year movements in industry productivity may be erratic, particularly in smaller industries. The annual measures based on sample data may differ from measures generated by a census of establishments in the industry. Annual changes in an industry's output and use of labor may reflect cyclical changes in the economy as well as long-term trends. As a result, long-term productivity trends tend to be more reliable indicators of industry performance than year-to-year changes.

Customers can subscribe to the industry productivity program's news releases on the BLS website at https://subscriptions.bls.gov/accounts/USDOLBLS/subscriber/new. More detailed data, including indexes, annual rates of change, and levels are available on the Labor Productivity and Costs web site at www.bls.gov/lpc. Additional information is available by calling the Division of Industry Productivity Studies (202-691-5618) or by sending a request by email to dipsweb@bls.gov. Information in this report will be made available to sensory-impaired individuals upon request. Voice phone: 202-691-5618; TDD message referral phone number: 1-800-877-8339.

Technical Note

Labor Productivity: The industry labor productivity measures describe the relationship between industry output and the labor time involved in its production. They show the changes from period to period in the amount of goods and services produced per hour. Although the labor productivity measures relate output to hours of all persons in an industry, they do not measure the specific contribution of labor or any other factor of production. Rather, they reflect the joint effects of many influences, including changes in technology; capital investment; utilization of capacity, energy, and materials; the use of purchased services inputs, including contract employment services; the organization of production; managerial skill; and the characteristics and effort of the workforce.

Output: Industry output is measured as an annual-weighted index of the changes in the various products or services (in real terms) provided for sale outside the industry. Real industry output is usually derived by deflating nominal sales or values of production using BLS price indexes, but for some industries it is measured by physical quantities of output.

Industry output measures are constructed primarily using data from the economic censuses and annual surveys of the U.S. Census Bureau, U.S. Department of Commerce, together with information on price changes primarily from BLS. Other data sources include the Energy Information Administration, U.S. Department of Energy; the Bureau of Transportation Statistics, U.S. Department of Transportation; the U.S. Geological Survey, U.S. Department of the Interior; the U.S. Postal Service; the Postal Rate Commission; and the Federal Deposit Insurance Corporation.

Labor Hours: The primary source of industry employment and hours data is the BLS Current Employment Statistics (CES) survey. The CES provides monthly data on the number of total and nonsupervisory worker jobs held by wage and salary workers in nonfarm establishments, as well as data on the average weekly hours of nonsupervisory workers in those establishments. CES data are supplemented with data from the Current Population Survey (CPS) to estimate employment and hours of self-employed and unpaid family workers in each industry. Data from the CPS, together with CES data, are also used to estimate the historical average weekly hours of supervisory workers for each industry. CES and CPS data are supplemented or further disaggregated for some industries using data from the BLS Quarterly Census of Employment and Wages (QCEW), the Census Bureau, or other sources. Other sources of employment and hours data for some service industries include the Association of American Railroads, the U.S. Department of Transportation, and the U.S. Postal Service. Hours of all persons in an industry are treated as homogeneous and are directly aggregated.

Unit Labor Costs: Unit labor costs represent the cost of labor required to produce one unit of output. The unit labor cost indexes are computed by dividing an index of industry labor compensation by an index of real industry output. Unit labor costs also describe the relationship between compensation per hour and real output per hour (labor productivity). Increases in hourly compensation increase unit labor costs; increases in labor productivity offset compensation increases and lower unit labor costs.

Labor Compensation: Labor compensation, defined as payroll plus supplemental payments, is a measure of the cost to the employer of securing the services of labor. Payroll includes salaries, wages, commissions, dismissal pay, bonuses, vacation and sick leave pay, and compensation in kind. Supplemental payments include legally required expenditures and payments for voluntary programs. The legally required portion consists primarily of Federal old age and survivors' insurance, unemployment compensation, and workers' compensation. Payments for voluntary programs include all programs not specifically required by legislation, such as the employer portion of private health insurance and pension plans.

Table 1. Percent change in output per hour, unit labor costs, and related data, 2010-2011

Industry	NAICS code	2011 Employment (thousands)	Percent change, 2010-2011				
			Output per hour	Output	Hours	Labor compensation	Unit labor costs
Mining Industries							
Mining	21	759.3	-11.3	4.2	17.5	16.6	11.9
Oil and gas extraction	211	173.0	-11.0	4.7	17.6	10.3	5.4
Oil and gas extraction	2111	173.0	-11.0	4.7	17.6	10.3	5.4
Mining, except oil and gas	212	221.2	-5.1	2.7	8.2	10.2	7.3
Coal mining	2121	87.5	-4.6	5.0	10.1	12.3	6.9
Metal ore mining	2122	42.4	-18.5	-2.0	20.2	19.8	22.3
Nonmetallic mineral mining and quarrying	2123	91.3	2.8	4.3	1.4	0.9	-3.3
Support activities for mining	213	365.1	-3.0	19.9	23.6	27.3	6.2
Support activities for mining	2131	365.1	-3.0	19.9	23.6	27.3	6.2
Utilities							
Power generation and supply	2211	398.4	-5.6	-4.5	1.1	3.9	8.8
Natural gas distribution	2212	107.9	4.3	0.7	-3.4	3.9	3.2
Transportation and Warehousing							
Air transportation	481	425.2	0.3	1.9	1.6	3.7	1.7
Line-haul railroads	482111	179.4	-2.7	3.8	6.8	10.5	6.4
Truck transportation	484	1,495.8	1.1	5.1	4.0	7.5	2.3
General freight trucking	4841	1,078.7	2.3	5.3	2.9	6.5	1.1
General freight trucking, local	48411	281.8	2.4	7.7	5.2	7.0	-0.7
General freight trucking, long-distance	48412	796.9	2.5	4.8	2.2	6.3	1.4
Used household and office goods moving	48421	86.6	-12.1	-3.5	9.8	5.7	9.5
Postal service	491	630.9	1.1	-2.7	-3.8	-0.5	2.3
Postal service	4911	630.9	1.1	-2.7	-3.8	-0.5	2.3
Couriers and messengers	492	561.3	0.6	-0.5	-1.1	5.0	5.6
Warehousing and storage	493	659.4	3.3	8.1	4.6	4.1	-3.7
Warehousing and storage	4931	659.4	3.3	8.1	4.6	4.1	-3.7
General warehousing and storage	49311	552.6	6.0	10.1	3.9	3.8	-5.8
Refrigerated warehousing and storage	49312	51.0	-11.8	-1.8	11.3	5.5	7.5
Information							
Publishing	511	788.8	1.0	2.4	1.4	6.2	3.7
Newspaper, book, and directory publishers	5111	517.2	-1.7	-2.5	-0.8	1.6	4.2
Software publishers	5112	271.6	1.0	6.4	5.3	10.3	3.7
Motion picture and video exhibition	51213	124.3	-0.1	-2.3	-2.2	-1.4	0.9
Broadcasting, except internet	515	291.4	3.5	2.9	-0.6	3.6	0.7
Radio and television broadcasting	5151	215.9	0.5	0.8	0.3	2.8	2.1
Cable and other subscription programming	5152	75.5	7.5	4.8	-2.5	5.1	0.3
Wired telecommunications carriers	5171	590.1	6.3	0.9	-5.2	-2.8	-3.7
Wireless telecommunications carriers	5172	169.6	10.0	10.5	0.5	5.6	-4.5
Finance and Insurance							
Commercial banking	52211	1,314.5	-2.8	-1.0	1.8	5.2	6.3
Real Estate and Rental and Leasing							
Passenger car rental	532111	101.0	15.2	12.9	-2.0	2.7	-9.1
Truck, trailer and RV rental and leasing	53212	55.8	5.9	4.1	-1.7	3.9	-0.2
Video tape and disc rental	53223	41.2	43.3	-16.0	-41.4	-30.4	-17.1
Professional and Technical Services							
Tax preparation services	541213	147.7	1.2	-0.4	-1.6	7.7	8.1
Architectural services	54131	177.4	5.3	3.9	-1.4	2.6	-1.2
Engineering services	54133	921.9	-1.7	1.9	3.6	3.6	1.7
Advertising agencies	54181	194.6	-0.8	5.0	5.9	9.8	4.5
Photography studios, portrait	541921	69.0	11.7	1.4	-9.2	-0.4	-1.9
Administrative and Waste Services							
Employment placement agencies	561311	237.9	9.0	15.7	6.1	8.0	-6.7
Travel arrangement and reservation services	5615	213.9	-2.0	5.4	7.5	6.7	1.3

Table 1. Percent change in output per hour, unit labor costs, and related data, 2010-2011 — Continued

Industry	NAICS code	2011 Employment (thousands)	Percent change, 2010-2011				
			Output per hour	Output	Hours	Labor compensation	Unit labor costs
Travel agencies	56151	98.2	3.5	6.5	2.9	9.6	2.9
Janitorial services	56172	1,262.2	2.5	4.0	1.5	3.5	-0.5
Health Care and Social Assistance							
Medical and diagnostic laboratories	6215	243.6	-2.2	3.9	6.3	3.4	-0.5
Medical laboratories	621511	168.0	-1.1	7.2	8.4	3.8	-3.2
Diagnostic imaging centers	621512	75.7	-2.6	-1.4	1.3	2.8	4.2
Arts, Entertainment, and Recreation							
Amusement and theme parks	71311	144.3	-0.9	4.6	5.5	5.0	0.3
Bowling centers	71395	68.6	-0.6	4.3	4.9	1.0	-3.1
Accommodation and Food Services							
Accommodation and food services	72	11,698.6	0.8	3.6	2.7	4.9	1.3
Accommodation	721	1,825.3	4.9	3.6	-1.3	5.1	1.5
Traveler accommodation	7211	1,752.2	4.8	3.5	-1.2	5.1	1.5
Food services and drinking places	722	9,873.3	-0.1	3.6	3.6	4.9	1.2
Full-service restaurants	7221	4,647.7	1.3	5.0	3.7	5.0	0.0
Limited-service eating places	7222	4,165.5	-2.1	2.8	5.0	3.7	0.9
Special food services	7223	692.4	3.3	2.5	-0.8	8.6	6.0
Drinking places (alcoholic beverages)	7224	367.7	2.1	-0.3	-2.4	3.3	3.7
Other Services							
Automotive repair and maintenance	8111	1,034.9	7.7	3.4	-4.0	-0.9	-4.1
Reupholstery and furniture repair	81142	19.7	5.5	-0.3	-5.5	2.7	3.0
Personal care services	8121	1,104.3	6.6	3.2	-3.2	-3.0	-6.0
Hair, nail and skin care services	81211	923.1	5.4	2.1	-3.2	-2.7	-4.7
Funeral homes and funeral services	81221	104.3	-4.5	0.3	5.0	2.8	2.4
Drycleaning and laundry services	8123	320.4	9.4	3.6	-5.3	0.7	-2.8
Coin-operated laundries and drycleaners	81231	41.9	15.7	-0.3	-13.8	2.0	2.3
Drycleaning and laundry services	81232	155.1	9.4	1.9	-6.9	-2.0	-3.8
Linen and uniform supply	81233	123.4	7.5	6.5	-0.9	2.4	-3.8
Photofinishing	81292	14.4	16.6	10.4	-5.3	13.9	3.2

Table 2. Average annual percent change in output per hour, unit labor costs, and related data, 1987-2011

Industry	NAICS code	Average annual percent change, 1987-2011				
		Output per hour	Output	Hours	Labor compensation	Unit labor costs
Mining Industries						
Mining	21	-0.4	0.1	0.5	5.2	5.1
Oil and gas extraction	211	0.5	-0.2	-0.7	5.5	5.7
Oil and gas extraction	2111	0.5	-0.2	-0.7	5.5	5.7
Mining, except oil and gas	212	1.5	0.4	-1.1	2.3	1.9
Coal mining	2121	1.6	-0.1	-1.7	1.3	1.5
Metal ore mining	2122	1.5	1.9	0.4	5.0	3.0
Nonmetallic mineral mining and quarrying	2123	0.7	-0.3	-1.0	2.5	2.8
Support activities for mining	213	1.3	4.1	2.7	8.4	4.1
Support activities for mining	2131	1.3	4.1	2.7	8.4	4.1
Utilities						
Power generation and supply	2211	1.9	0.7	-1.2	2.9	2.2
Natural gas distribution	2212	2.7	1.2	-1.5	3.4	2.1
Transportation and Warehousing						
Air transportation	481	3.1	2.7	-0.4	2.8	0.1
Line-haul railroads	482111	3.9	2.0	-1.8	1.5	-0.5
Truck transportation[1]	484	0.6	1.7	1.1	2.5	0.8
General freight trucking[1]	4841	1.4	2.3	0.9	3.0	0.7
General freight trucking, local[1]	48411	3.0	3.6	0.6	3.7	0.1
General freight trucking, long-distance	48412	1.4	2.3	0.9	2.3	0.0
Used household and office goods moving	48421	-1.2	-1.1	0.1	1.9	3.0
Postal service	491	0.9	-0.3	-1.2	3.5	3.8
Postal service	4911	0.9	-0.3	-1.2	3.5	3.8
Couriers and messengers	492	-0.8	1.2	2.0	4.6	3.3
Warehousing and storage[1]	493	2.9	5.8	2.8	5.2	-0.5
Warehousing and storage[1]	4931	2.9	5.8	2.8	5.2	-0.5
General warehousing and storage[1]	49311	5.2	8.0	2.7	5.7	-2.2
Refrigerated warehousing and storage[1]	49312	-0.2	3.1	3.3	4.3	1.1
Information						
Publishing	511	3.8	3.5	-0.3	5.1	1.5
Newspaper, book, and directory publishers	5111	0.0	-1.8	-1.8	2.2	4.1
Software publishers	5112	13.0	19.7	6.0	11.6	-6.8
Motion picture and video exhibition	51213	1.4	1.6	0.2	3.2	1.6
Broadcasting, except internet	515	2.1	2.6	0.5	4.4	1.8
Radio and television broadcasting	5151	1.0	0.7	-0.4	3.0	2.3
Cable and other subscription programming	5152	3.9	7.5	3.5	10.5	2.8
Wired telecommunications carriers	5171	4.3	3.3	-1.0	2.0	-1.2
Wireless telecommunications carriers	5172	10.4	20.7	9.3	12.2	-7.1
Finance and Insurance						
Commercial banking	52211	3.6	3.6	-0.1	5.5	1.9
Real Estate and Rental and Leasing						
Passenger car rental	532111	2.6	2.7	0.1	4.8	2.0
Truck, trailer and RV rental and leasing	53212	2.9	2.0	-0.9	2.9	0.9
Video tape and disc rental	53223	6.4	1.7	-4.4	-0.7	-2.4
Professional and Technical Services						
Tax preparation services	541213	0.6	2.7	2.1	4.3	1.6
Architectural services	54131	1.2	2.0	0.8	4.1	2.1
Engineering services	54133	0.9	2.7	1.7	6.1	3.4
Advertising agencies	54181	2.2	2.5	0.3	4.7	2.1
Photography studios, portrait	541921	0.8	1.8	1.0	3.7	1.9
Administrative and Waste Services						
Employment placement agencies[2]	561311	6.4	7.2	0.8	5.5	-1.6
Travel arrangement and reservation services[3]	5615	7.5	3.5	-3.6	1.2	-2.3

See footnotes at end of table.

Table 2. Average annual percent change in output per hour, unit labor costs, and related data, 1987-2011 — Continued

Industry	NAICS code	Average annual percent change, 1987-2011				
		Output per hour	Output	Hours	Labor compensation	Unit labor costs
Travel agencies	56151	5.9	4.2	-1.6	3.1	-1.1
Janitorial services	56172	2.0	3.7	1.6	5.3	1.5
Health Care and Social Assistance						
Medical and diagnostic laboratories[2]	6215	2.9	6.2	3.2	5.9	-0.2
Medical laboratories[2]	621511	2.5	5.7	3.1	5.5	-0.3
Diagnostic imaging centers[2]	621512	3.3	6.9	3.5	7.0	0.1
Arts, Entertainment, and Recreation						
Amusement and theme parks	71311	-0.5	2.3	2.8	6.0	3.6
Bowling centers	71395	0.2	-1.6	-1.8	1.0	2.7
Accommodation and Food Services						
Accommodation and food services	72	0.8	2.1	1.2	4.9	2.8
Accommodation	721	1.7	2.3	0.6	4.6	2.2
Traveler accommodation	7211	1.7	2.4	0.6	4.6	2.1
Food services and drinking places	722	0.6	2.0	1.4	5.1	3.0
Full-service restaurants	7221	0.6	2.1	1.4	5.9	3.7
Limited-service eating places	7222	0.6	2.1	1.6	4.9	2.7
Special food services	7223	1.4	2.4	0.9	3.7	1.2
Drinking places (alcoholic beverages)	7224	-0.3	-0.7	-0.4	2.4	3.1
Other Services						
Automotive repair and maintenance	8111	1.0	1.2	0.1	3.4	2.2
Reupholstery and furniture repair	81142	-0.6	-3.2	-2.6	0.2	3.6
Personal care services	8121	2.2	3.3	1.0	4.9	1.6
Hair, nail and skin care services	81211	2.2	3.0	0.8	4.7	1.7
Funeral homes and funeral services	81221	-0.7	-0.5	0.2	3.8	4.3
Drycleaning and laundry services	8123	1.6	0.5	-1.2	2.4	2.0
Coin-operated laundries and drycleaners	81231	2.5	0.4	-2.0	2.2	1.8
Drycleaning and laundry services	81232	1.1	-1.1	-2.2	1.0	2.1
Linen and uniform supply	81233	1.2	1.8	0.6	3.9	2.1
Photofinishing	81292	2.8	-4.3	-6.9	-2.5	1.9

1 For NAICS industries 484, 4841, 48411, 493, 4931, 49311, and 49312, average annual percent changes are for 1992-2011.
2 For NAICS industries 561311, 6215, 621511, and 621512, average annual percent changes are for 1994-2011.
3 For NAICS industry 5615, average annual percent changes are for 1997-2011.

Industry Labor Productivity and Costs: Percent Changes - August 29, 2013

Indent Level	Industry and Year	NAICS code	Output per hour	Output per person	Output	Implicit price deflator	Hours	Employment	Unit labor costs	Labor compensation
0	Electric power generation, transmission and distribution									
1	2007	2211	-1.7	0.7	1.0	2.5	2.8	0.4	1.9	3.0
1	2008	2211	-4.1	-3.1	-1.6	6.1	2.6	1.5	10.3	8.5
1	2009	2211	-2.4	-3.7	-3.6	0.9	-1.3	0.1	5.2	1.3
1	2010	2211	3.3	3.0	1.5	0.1	-1.8	-1.5	-0.5	1.0
1	2011	2211	-5.6	-4.6	-4.5	1.9	1.1	0.1	8.8	3.9

Source: Bureau of Labor Statistics, excerpt from file "ipr.airt.xls"

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY

OF

SUSAN D. RITENOUR

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Susan D. Ritenour
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Susan Ritenour. My business address is One Energy Place, Pensacola, Florida 32520 and I am the Corporate Secretary, Treasurer and Corporate Planning Manager for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony shows that Office of Public Counsel (OPC) Witness Garrett's proposed rate base adjustment related to the property damage reserve reflects a misunderstanding of the nature of, and current accounting for, that reserve. In addition I show that in making their adjustments to the property damage accrual, Mr. Garrett and Federal Executive Agencies (FEA) Witness Meyer failed to reflect the appropriate rate base impacts of their recommendations. Similarly, OPC Witness Pous failed to adjust accumulated depreciation to properly reflect the impact of his proposed adjustments to depreciation and dismantlement expense. Finally, I show that the increase identified by Mr. Meyer in Gulf's transmission rent expense is not a base rate issue.

Q. Are you sponsoring any rebuttal exhibits?
A. No.

Q. Is Mr. Garrett's proposed adjustment related to Gulf's storm damage reserve appropriate?
A. No. Mr. Garrett's recommendation that "the Company discontinue the accruing of interest on the storm reserve balance and instead include the balance as an offset to rate base" reveals that he is not familiar with either the accounting for or the current regulatory treatment of Gulf's property damage reserve. Simply stated, Gulf does not accrue interest on its property damage reserve and the unfunded balance of the reserve on Gulf's balance sheet is already included as a credit to rate base for both surveillance and ratemaking purposes.

Q. Please explain.
A. Gulf maintains a funded reserve in which the after-tax portion of the dollars accrued to the property damage reserve are placed annually into a segregated, interest-bearing investment account that is available only to pay costs to repair uninsured property damage. For ratemaking purposes, the funded amount is removed from other property and investments and from the property damage reserve, as shown on Schedule 11 of my Exhibit SDR-1. The remaining balance of the property damage reserve, the

unfunded amount, currently receives the ratemaking treatment that Mr. Garrett proposes. The working capital allowance in Gulf's 2014 test year rate base already reflects a credit balance (a reduction to rate base) equal to the unfunded portion of the reserve. Because the funded portion of the reserve balance earns interest and is not available for general corporate purposes, it would be inappropriate to reduce rate base by the balance in that account.

In summary, Gulf's accounting for its property damage reserve is correct, has been approved by the Commission in past rate case proceedings, and already gives Gulf's customers a rate base credit for the unfunded portion of the reserve. No additional adjustment is appropriate.

Q. Mr. Meyer and Mr. Garrett recommend decreases to the amount of the accrual to the property damage reserve. However, they do not propose a corresponding adjustment to the property damage reserve itself. Is this appropriate?

A. No. Other Gulf witnesses show why the Commission should reject the intervenor proposals to adjust Gulf's requested accrual to the property damage reserve. However, if an adjustment to the amount of the annual accrual is made, the Commission must recognize that any decrease to the amount of the accrual will also decrease the amount of the accumulated balance in the property damage reserve. The 13-month average impact of any such change should be reflected in an adjustment to rate base. In the case of Mr. Meyer's recommendation to reduce the Company's requested annual accrual by $5,500,000, a corresponding adjustment of $2,750,000 to decrease the property damage reserve, and thus increase system rate base, is necessary. A larger rate base adjustment of $4,500,000 is required to properly quantify the full impact of Mr. Garrett's recommendation to completely cease making any annual accrual to the property damage reserve.

Q. In his testimony, Mr. Pous recommends changes to depreciation and dismantlement expense for the 2014 test year, but he does not recommend an adjustment to test year accumulated depreciation. Is this appropriate?

A. No. Again, other Gulf witnesses show why the Commission should reject any change to Gulf's proposed depreciation and dismantlement expense. However, if depreciation or dismantlement expense changes, so does accumulated depreciation. Mr. Pous proposes a large reduction to depreciation and dismantlement, which would result in a corresponding reduction to the accumulated depreciation balance and therefore an increase to rate base. However, he proposes no adjustment to reflect the increase to 13-month average rate base in the test year that would result if his changes to expense were made. By excluding the rate base adjustment, the impact on Gulf's revenue requirements associated with changes to depreciation and dismantlement proposed by Mr. Pous is misstated.

Q. Did you note any other inconsistencies in Mr. Pous' testimony?

A. Yes. In his discussion of Gulf's calculation of dismantlement costs, he uses Plant Scherer as an example. It is important to note that Plant Scherer is used to make wholesale sales and therefore it is not included in retail base rates. As I discuss in my direct testimony, all amounts associated with Plant Scherer have been removed from the 2014 test year rate base, net operating income and capital structure. Any changes in depreciation or dismantlement expense associated with Plant Scherer do not affect the Company's base rate revenue request in this proceeding.

Q. Although he proposes no adjustment, Mr. Meyer expresses concern about the increase over historic levels in the amount of transmission rent in 2013 and 2014. Are these costs included in the 2014 test year?

A. No. All of the increase in transmission rent is related to transmission required in connection with Commission-approved power purchase agreements. That expense is recovered through the Capacity Cost Recovery Clause and is not included in Gulf's base rate request (see my Exhibit SDR-1, Schedule 12, page 3 of 3, line 12 showing the adjustment of $13,221,000 to remove the transmission expenses recovered through the capacity clause). Of the $13,386,000 in transmission rents referred to in Mr. Meyer's testimony, only $165,000 is included for recovery through base rates.

Q. Does that conclude your rebuttal testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

ANGELA G. STRICKLAND

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Angela G. Strickland
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Angela Strickland. My business address is One Energy Place, Pensacola, Florida 32520 and I am the General Manager of Marketing for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the direct testimony of Office of Public Counsel (OPC) Witness Garrett as it relates to the customer satisfaction portion of Gulf's at-risk compensation. Additionally, I will address statements made in the direct testimony of Wal-Mart Witness Chriss as it relates to Gulf's proposed Large Business Incentive Rider (LBIR).

Q. Are you sponsoring any rebuttal exhibits?

A. Yes. I am sponsoring Exhibit AGS-2, consisting of 1 schedule. This exhibit was prepared under my direction and control, and the information contained therein is true and correct to the best of my knowledge.

I. AT-RISK COMPENSATION – CUSTOMER SATISFACTION MEASURE

Q. What are your concerns regarding Mr. Garrett's testimony?

A. Mr. Garrett suggests that the Florida Public Service Commission (FPSC or the Commission) should disallow a portion of the Company's at-risk compensation based upon residential customer satisfaction rankings by J.D. Power and Associates. For reasons I describe below, I disagree with Mr. Garrett's proposal and his singular reliance on the J.D. Power survey as representing the sentiment of all Gulf customers. Gulf's customers are at the center of everything we do and we are constantly striving to develop and enhance ways to assess and improve their satisfaction.

Q. Please describe the primary tool that Gulf uses to measure customer satisfaction.

A. Gulf uses a sophisticated research tool, known as the Customer Value Benchmark (CVB), to compare and contrast itself against an elite group of 16 peer utilities in the Southeast and nationally. The CVB is a proprietary tool in which customer value is measured in three customer segments: large business, general business, and residential. Additionally, an overall ranking is developed based on the results of these three segments. All customer segments, including the overall rank, are considered when calculating the customer satisfaction portion of Gulf's at-risk compensation. The CVB is a "customer designed score card" which represents issues that are of particular importance to Gulf's customers.

Research for the residential and general business segments is done by surveying a random sampling of customers in each segment for Gulf and each company in the peer group. Selected customers are called and asked a set of questions based on a pre-determined set of key performance indicators. For the residential segment, online surveys are also conducted.

For large business customers, data for the CVB is collected through a syndicated study. Large business customers who meet the survey criteria are called and asked a similar set of questions. In the large business segment, the goal is to survey all qualifying customers of the Company and each of the companies in the peer group.

Q. You described the CVB as a "customer designed scorecard"; please elaborate on what you mean by this.

A. "Voice of the Customer" research is conducted with customers periodically to identify issues that are of particular importance to them. The results of this research are compiled and adjustments are made to the CVB survey instrument to ensure we measure satisfaction for issues that our customers say are important. "Voice of the Customer" research was performed in 2010 and as a result, we made changes to our 2012 survey. One finding from that research was that customers' expectations evolved and they now expect options for receiving their bill (i.e., email, online, etc.). As a result, we added a new survey question for customers to rate on a scale of one to ten: "Provides options for receiving and viewing your monthly bill." This process results in a survey instrument that is not only "customer designed," but is adaptive, evolving as customers' concerns evolve over time.

Q. Where does Gulf rank when compared to the peer utilities in the CVB survey?

A. As shown in Schedule 2 of Exhibit AGS-1 attached to my direct testimony, Gulf was in the top quartile overall in 2012. Gulf's overall top quartile performance has been consistent since 2000. We are proud of our performance when compared to the top utilities across the country. This outstanding performance is a testament to the focus Gulf's employees maintain on exceeding our customers' expectations each and every day.

Since filing direct testimony, Gulf received 2013 results for the CVB. Those results for all customer classes as well as the overall rankings are found in Schedule 1 of my Exhibit AGS-2. Gulf's 2013 results demonstrate not only overall results that remain in the upper quartile, but also improvements in Gulf's rankings in all three customer classes over 2012.

Q. Why does Gulf rely on the CVB to measure customer satisfaction for purposes of at-risk compensation and not J.D. Power or other available tools?

A. While there is certainly more than one tool to measure customer satisfaction in a general sense, for purposes of Gulf Power's operational goals, the CVB is the best measurement. Because the CVB is a "customer-designed scorecard" which not only addresses issues but also gives weight to the issues that our customers have said are important to them, the perceptions being measured are more representative of our customers' sentiments and more appropriate for use in assessing achievement of Gulf's customer satisfaction operational goals.

Moreover, as I stated previously, the CVB measures customer satisfaction representing all of our customer segments: residential, general business and large business. The J.D. Power survey referenced by Mr. Garrett focuses solely on the residential segment. Excluding the sentiments of one or more customer segments when gauging customer satisfaction disenfranchises that group of customers and potentially misrepresents the sentiments of customers overall.

Further, in the CVB, Gulf is compared against 16 peer utilities that were specifically selected because of their similarities. Peers are selected because they are geographically one system away, could compete directly for Gulf's current customers, or they compete with Gulf and/or Southern Company on a national basis. Companies considered as competitors nationally are determined by how similar they are to Gulf and the other Southern Company utilities. This similarity is determined based on a variety of factors which include, but are not limited to, market capitalization, fuel mix, customer mix and regulatory environment. This customized and purposeful approach to peer selection provides comparisons that are more appropriate for use in assessing achievement of operational goals.

Q. Please describe Gulf's performance in the area of customer satisfaction from 2009 through 2013 as measured by the CVB.

A. As described in my direct testimony on page 28, Gulf's overall performance, representing all customer segments, has consistently been in the top quartile since 2000. That trend continued in 2013. The CVB results for large business customers have also been very strong with consistent top quartile performance. General business results have been strong, with Gulf falling just outside the top quartile in 2010 and 2011, but landing firmly in the top quartile otherwise. Residential results declined between 2009 and 2012; however, they made a strong comeback in the 2013 CVB, as shown in Schedule 1 of my Exhibit AGS-2, placing Gulf third overall when compared to the peer group.

Q. What actions has Gulf undertaken to improve customer satisfaction as measured in the CVB?

A. As Gulf Witness Neyman discusses in her direct testimony, Gulf listens when our customers provide us with feedback. We employ more tools than just the CVB to hear from customers and embrace their suggestions and make targeted adjustments to better serve them. Ms. Neyman describes many actions the Company has taken which are largely targeted at the residential segment of customers to enhance the level of service that we provide.

Among other actions, Gulf has added Care Representatives in the local offices and provided them with additional training to equip them to provide the same services which are offered by the Customer Care Center. Gulf's customer care representatives recently completed comprehensive classroom training on empathy. This training helps even the most senior of our representatives stay mindful of how they communicate with customers.

Moreover, Gulf has undertaken a number of initiatives in direct response to CVB feedback, including commissioning the Active Customer Survey, comprehensive customer value training for all employees, adding more customized service for businesses calling the Customer Care Center and renovating some local offices to provide a more pleasant, modern and efficient environment for our customers to conduct business with us. We believe that all of these actions have resulted in improved satisfaction among our residential customers. These results are clearly seen in 2013 residential satisfaction as measured by both CVB and J. D. Power.

Q. What is the Active Customer Survey that you mentioned and how does Gulf use that tool?

A. As described in my direct testimony, the Active Customer Survey is a survey tool used to measure satisfaction and obtain feedback from customers who had a recent contact with the Company. We perform Active Customer Surveys year round and continuously look for trends in the results that assist us in developing targeted process improvements that respond directly to feedback from our customers.

Q. What other indicators demonstrate that Gulf delivers strong customer satisfaction?

A. The Company's complaint activity with the Commission has decreased each year since 2010. Additionally, Gulf has had only one infraction with the Commission in the last 12 years and that one infraction was due to a timing issue where Gulf's response was one minute late. These results further demonstrate Gulf's commitment and success in delivering customer value.

Additionally, the FPSC Commissioners had the opportunity to hear directly from Gulf's customers at service hearings held in September of this year. Gulf's customers consistently expressed to the Commissioners their satisfaction with Gulf's level of service (reliability and customer service). A residential customer commented "I would like to thank the service of Gulf Power Company for their good service that they have provided to Bay County over a number of years. I have never called them that they didn't come out and produce and fix whatever the problem was." [September 4, 2013, TR page 22] Another customer said "...Gulf offers excellent service." [September 3, 2013, TR page 40] He went on to say "...I spend on electricity about fifty to sixty thousand dollars a year, so my electric bill is very important to me. But it is also important that I have reliable power, high quality power, power that is free of harmonics, power that has good power regulation, and Gulf Power has delivered on that." [September 3, 2013, TR page 41]

Q. Would you summarize Gulf's customer satisfaction record?

A. The Company genuinely places our customers at the center of everything that we do. This focus is evident in the results that we deliver. Gulf's customer satisfaction rankings as measured by the CVB demonstrate that we maintain these results. Further, when we begin seeing declines in a particular customer group, we take swift action to understand the customers' concerns and develop specific actions to make adjustments. The actions we undertook in the residential segment have and will continue to deliver great results to our customers. These results are clearly seen in 2013 residential satisfaction as measured by both CVB and J. D. Power. We are proud of our 2013 customer satisfaction results and look forward to continuing to build on those results in 2014 and beyond.

The CVB is the best available customer satisfaction tool to use in measuring our operational success.

II. LARGE BUSINESS INCENTIVE RIDER

Q. What recommendation has Mr. Chriss made with respect to Gulf's proposed economic development rate riders?

A. Mr. Chriss recommends that the load threshold for the Large Business Incentive Rider (LBIR) be changed from 1,000 kW to 200 kW. Notably, Mr. Chriss does not recommend making any other changes to the LBIR and supports the Small Business Incentive Rider (SBIR) as proposed by Gulf.

For reasons described below, I respectfully disagree with Mr. Chriss' suggestion as both of these riders were purposefully designed including a number of qualifications, minimum load being only one of those.

Q. Please describe Gulf's proposed LBIR.

A. The LBIR is available to prospective customers having a new load of at least 1,000 kW. The credits under this Rider begin in year one with 60 percent of a customer's energy and demand charges and decline going forward. Year two credit is 45 percent, year three is 30 percent and year four, the final year, is 15 percent. In order to qualify for LBIR credits, the prospective customer must provide audit documentation from the Florida Department of Economic Opportunity demonstrating the hiring of at least 25 full-time employees per 1,000 kW of qualifying load. Additionally, under this Rider, the customer must also demonstrate new capital investment of at least $1,000,000 and provide an affidavit verifying that the availability of this Rider was a significant factor in their decision to request service from Gulf Power.

Q. Why was the LBIR designed for new load of at least 1,000 kW?

A. The credits offered in the proposed LBIR are intended to target prospective customers that have the opportunity to bring high levels of new load to Gulf's system. Examples of qualifying loads under the LBIR include pulp/paper mills, chemical plants, and large manufacturing plants. The credits available to qualifying customers were designed in recognition of the long term benefit that these large loads will bring to all of Gulf's customers.

Additionally, targeting loads of 1,000 kW and above has the potential to diversify Northwest Florida's economy. As described in my direct testimony, the main economic drivers in Northwest Florida are tourism and the military. While these industry sectors are certainly important, our economy remains vulnerable to downturns in one or both sectors. The LBIR, coupled with other programs like Gulf's recently launched site-certification program, were designed to target larger customers (many of which are often industrial in nature) and help bring that needed diversity to the area.

Q. Why do you disagree with Mr. Chriss' proposal that the LBIR load threshold should be lowered to 200 kW?

A. I have several concerns with the proposal to lower the LBIR threshold to 200 kW. First, I believe lowering the qualifying load threshold to 200 kW would undermine the objectives I previously described.

Second, I disagree with the assertion that the 1,000 kW threshold should be lowered because it provides a disincentive for customers to engage in installing energy efficiency measures in their business and that lowering the threshold will remove this disincentive. Changing the threshold, whether higher or lower, does not remove the alleged disincentive, it simply moves it to a different group of customers based on their size.

Third, the proposal to lower the LBIR threshold to 200 kW also overlooks the fact that both riders were purposefully designed and that the participation requirements must be considered as a whole. The 1,000 kW threshold as well as the other requirements were chosen in concert with the credit levels recognizing that potential new load of that size will, in the long term, provide greater benefit to all of Gulf's customers. These benefits will come in the form of utility costs being spread over a larger number of customers as well as increased jobs in Northwest Florida. Further, having a 200 kW threshold for both the LBIR and SBIR would create an opportunity for confusion among Gulf's customers, and the ensuing administrative challenges.

Finally, I would note that the LBIR, as well as the SBIR are being proposed as experimental rate riders applicable to new load connected not later than December 31, 2015. The experimental designation provides the opportunity to test the riders on a limited basis. If our experience suggests that the 1,000 kW threshold, or any other aspect of the riders, need to be modified then we will seek the appropriate approvals. In the meantime, the Company believes that it should be provided an opportunity to implement the riders as they have been proposed.

Q. Does Gulf have offerings for smaller customers who represent economic development opportunities for the area?

A. Yes. Gulf's customers stand to benefit from new load, large or small. Therefore, while the LBIR is designed to reach larger customers, the Company is also proposing a SBIR which is available to customers having a new load of at least 200 kW. Consequently, many new customers which cannot meet the load threshold for LBIR, would still have the opportunity to seek the SBIR for rate treatment.

Q. Would you summarize Gulf's position on economic development and the proposed LBIR?

A. Gulf fully supports economic development in the region. Gulf has been engaged in economic development activities across the region for many years. The Company stands beside all of our customers, including the customers that Mr. Chriss represents, in supporting the success and expansion of their business activities.

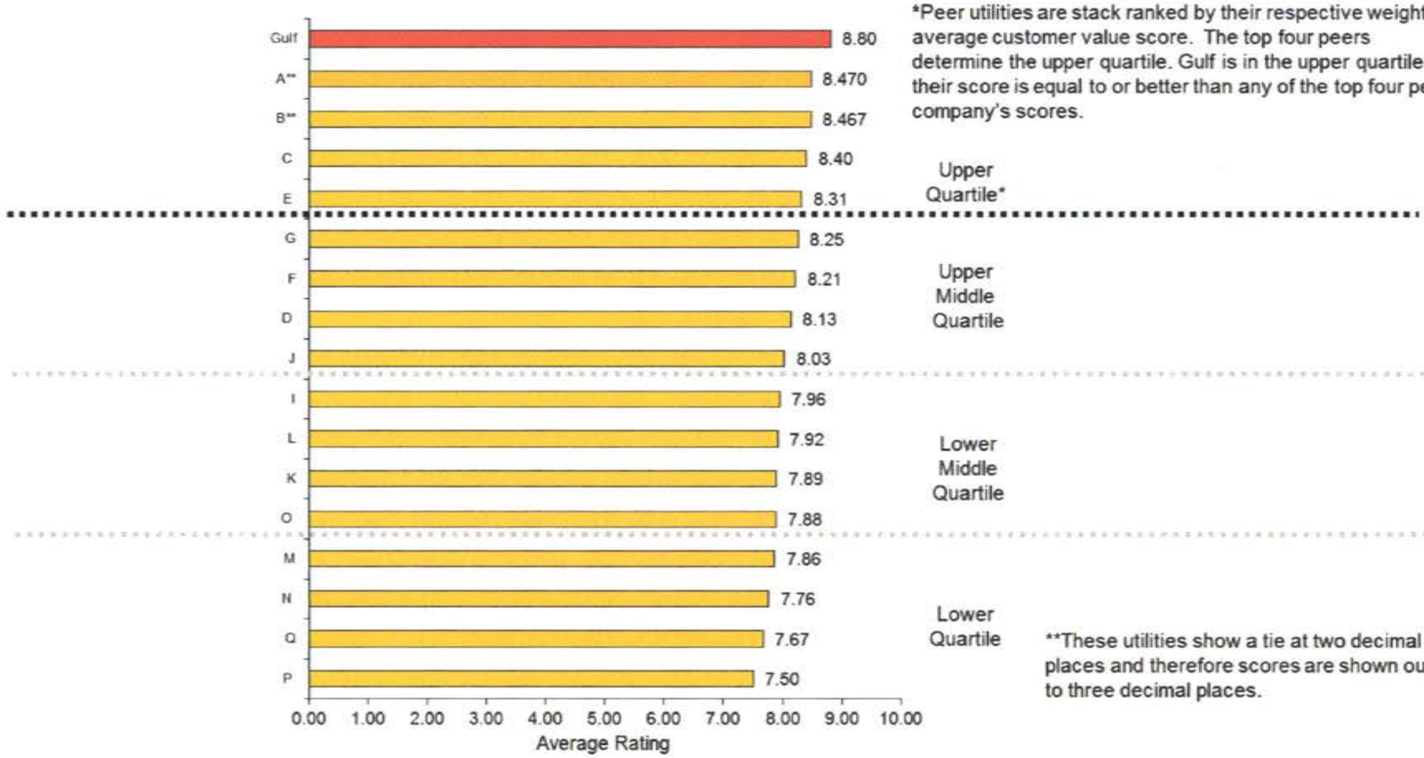
Gulf also recognizes that there is much work still to be done in the area of economic development and the LBIR and SBIR are two tools that we propose in helping to further success in this area. These tools were purposefully developed to target different groups of business customers and the Company requests that they be approved as designed.

Q. Ms. Strickland, does this conclude your rebuttal testimony?

A. Yes.

Exhibit

2013 Summary CVB Rank Chart – All Customer Classes



*Peer utilities are stack ranked by their respective weighted average customer value score. The top four peers determine the upper quartile. Gulf is in the upper quartile if their score is equal to or better than any of the top four peer company's scores.

**These utilities show a tie at two decimal places and therefore scores are shown out to three decimal places.

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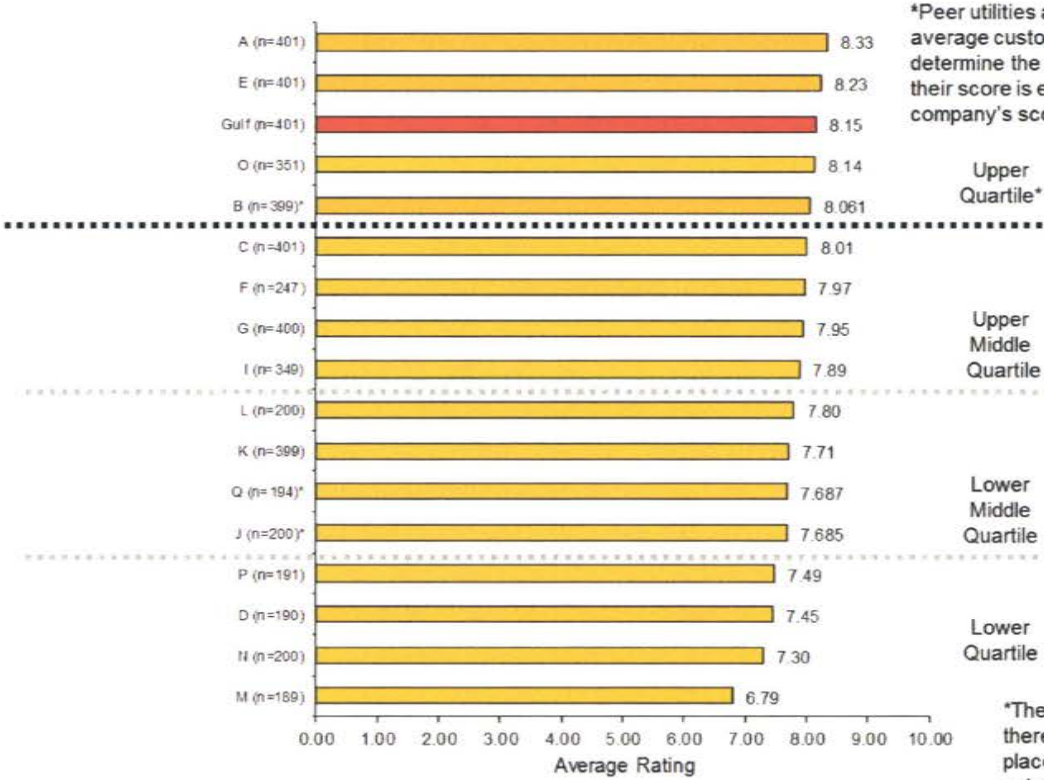
2013 Perceived Value Rank Chart – Residential Customers



*Peer utilities are stack ranked by their respective weighted average customer value score. The top four peers determine the upper quartile. Gulf is in the upper quartile if their score is equal to or better than any of the top four peer company's scores.

*These utilities show a tie at two decimal places and therefore scores are shown out to three decimal places. All rankings are based on respondent level calculations out to several decimal places.

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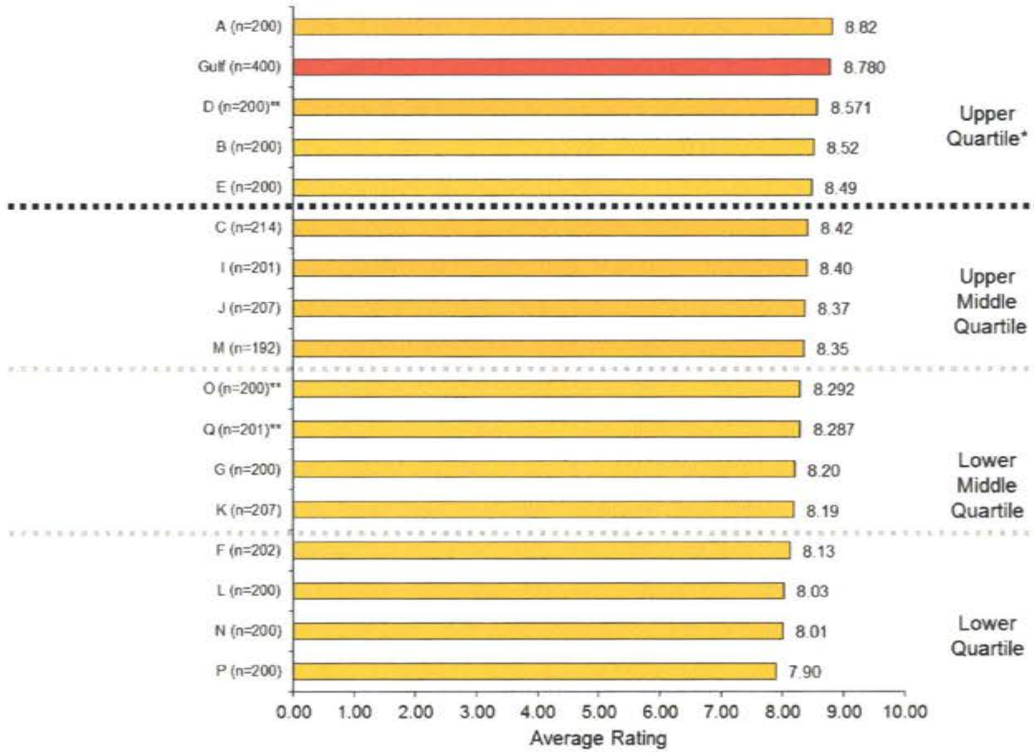
2013 Perceived Value Rank Chart – General Business Customers



*Peer utilities are stack ranked by their respective weighted average customer value score. The top four peers determine the upper quartile. Gulf is in the upper quartile if their score is equal to or better than any of the top four peer company's scores.

**These utilities show a tie at two decimal places and therefore scores are shown out to three decimal places. All rankings are based on respondent level calculations out to several decimal places.

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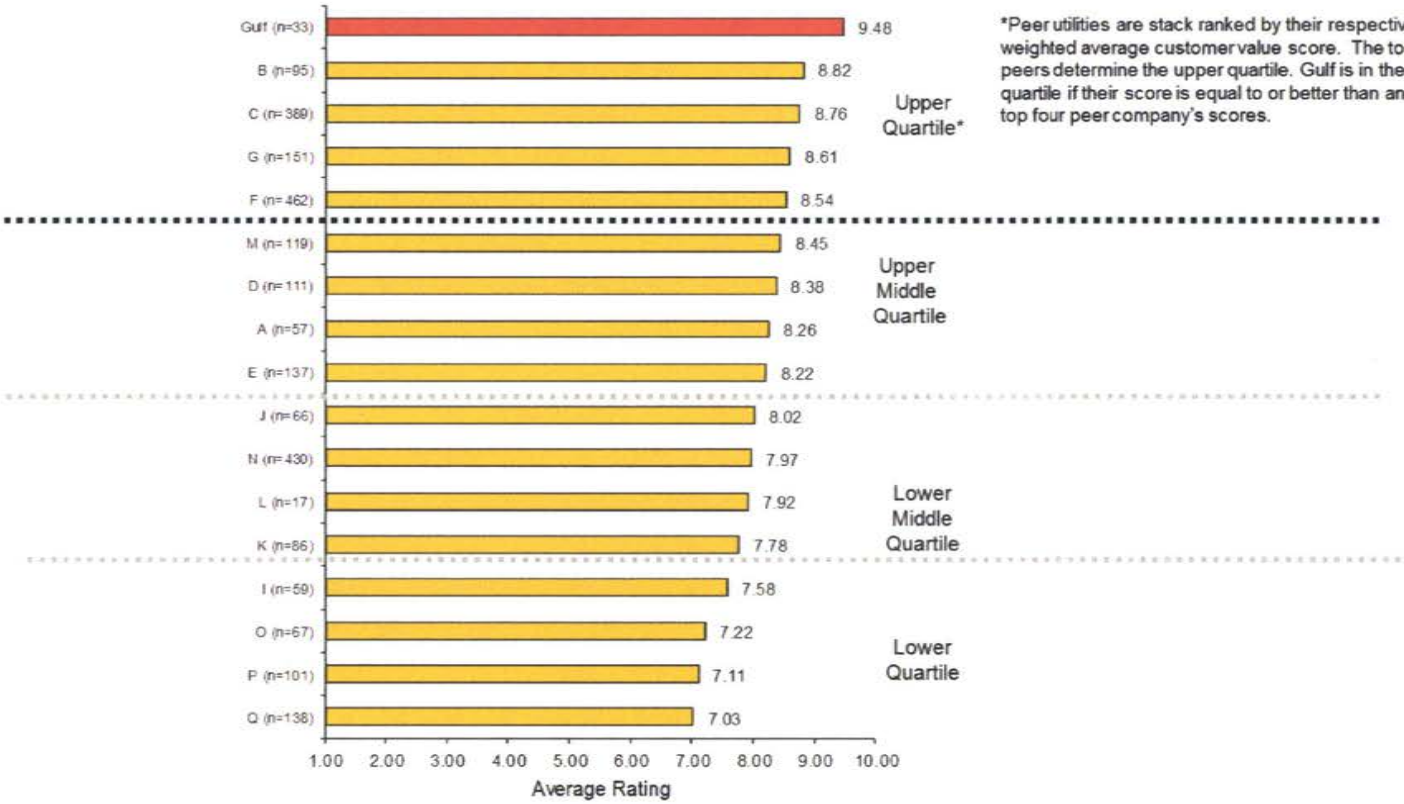
2013 Perceived Value Rank Chart – Large Business Customers



*Peer utilities are stack ranked by their respective weighted average customer value score. The top four peers determine the upper quartile. Gulf is in the upper quartile if their score is equal to or better than any of the top four peer company's scores.

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

R. SCOTT TEEL

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Rebuttal Testimony of
R. Scott Teel
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

Q. Please state your name and business address.

A. My name is Scott Teel. My business address is One Energy Place, Pensacola, FL 32520.

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

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

Q. Did you file direct testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to discuss the effect on Gulf of the proposed adjustments to Gulf's revenue requirements set forth in the testimony submitted by the intervenors -- Office of Public Counsel (OPC), Federal Executive Agencies (FEA), and Wal-Mart -- and the devastating impact on Gulf's financial integrity if all of their recommendations were adopted.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes. Exhibit RST-2 was prepared under my direction and control. The information contained in that exhibit is true and correct to the best of my knowledge and belief.

Q. What is the magnitude of the intervenors' proposed adjustments to Gulf's revenue requirement in the test year?

A. If accepted by the Commission, the aggregate effect of the intervenors' recommendations would be to reduce Gulf's rate request by well over $100 million, resulting in a rate decrease of well over $25 million.

Q. Is there a way to evaluate the reasonableness or unreasonableness of the aggregate recommendations of the intervenors to reduce Gulf's rates?

A. Yes. Exhibit RST-2 is an updated version of Schedule 5 to my direct testimony. This updated exhibit provides context for the intervenors' recommendations by showing Gulf's actual returns for the months subsequent to our initial filing. It shows that since our last rate case, Gulf's return on equity has never reached even the bottom of its currently authorized range and the downward trend of our actual results is consistent with what we were forecasting at the time this case was filed.

In evaluating the intervenors' proposal to reduce Gulf's rates, the Commission should ask two questions:

1. With this information on Gulf's actual and projected returns, would the Commission seriously entertain a petition filed by OPC to reduce Gulf's current rates?

2. If the earnings situation were reversed – that is, if Gulf had earned above the top of its range for over four years and its projected earnings were continuing to grow – would the Commission seriously entertain a rate increase?

The only reasonable answer to both questions is "absolutely not."

Q. In your direct testimony, you describe Gulf's required investment in infrastructure and its reduced level of sales as the primary drivers of the need for rate relief in the test year. How did the intervenors address these issues?

A. Essentially, they did not address either of these factors. Their testimony does not address, much less dispute, our need for the capital investment reflected in the test year's revenue requirements. With respect to our sales forecast, the only adjustments proposed appear to be based on a lack of understanding by witnesses who exhibit no appreciation of, or any effort to understand, the sophisticated modeling required to develop a sound sales forecast. The intervenors' adjustments are not supported by any empirical evidence and are without merit. Gulf Witness Alexander addresses the proposed adjustments to our sales forecast in her rebuttal testimony.

Q. How then do the intervenors reach the conclusion that a rate increase is not necessary, much less that a rate decrease should be ordered?

A. Their adjustments include a number of proposals to inappropriately disallow the recovery of certain costs, many of which have been previously recognized by the Commission as necessary as recently as 2012.

Some of their other proposed adjustments are arbitrary in nature, clearly based on "eyeball" tests and the intuition of witnesses without any experience in the relevant field. Perhaps, the best example of this is FEA Witness Meyer's proposed \$5.7 million adjustment to Production O&M. Rather than relying on the experience and operational expertise of our plant production employees to determine the costs to operate and maintain our electric generation facilities, Mr. Meyer implies that the Company could have accountants determine those needs with nothing more than accounting data and a calculator. Gulf Witness Grove addresses Mr. Meyer's proposal in his rebuttal testimony. These types of adjustments reflect a complete disregard for the expertise and diligence of Gulf's subject matter experts in determining the prudent and necessary costs to serve our customers.

The intervenor witnesses also propose adjustments to depreciation and storm accruals that would merely defer the recovery of current costs of service to future generations of customers.

However, the two largest adjustments are related to the cost of capital, which I will discuss later.

Q. The intervenors also recommend the rejection of Gulf's request for a step increase in 2015. Is it necessary to approve this increase now?

A. Yes. As explained in detail by Gulf Witnesses Vick, Burleson and Caldwell, the transmission investments associated with this need are prudent and necessary. The transmission improvements are very clearly in response to the MATS rules and part of the most cost effective solutions to comply with these new environmental regulations. The projects are not speculative. Construction is underway and the costs are determinable.

Rejecting our request for a step increase in this case will unnecessarily require another costly proceeding in the future, serving only to increase the effective cost of these essential investments to our customers.

Q. Please describe the intervenors' proposed adjustments related to cost of capital.

A. First, FEA Witness Gorman proposes that a 9.45% return on equity (ROE) will be sufficient to satisfy equity investors and will be supportive of credit quality. OPC Witness Woolridge goes even further and suggests that a 9.0% ROE would be satisfactory. Dr. Woolridge's recommendation calls for a reduction to revenue requirements of $28.6 million.

Second, Mr. Gorman proposes modifications to the Commission's policy for reconciling rate base and capital structure. If the Commission were to adopt his methodology, Mr. Gorman recommends a $25.5 million dollar reduction in revenue requirements based on his proposed capital structure and cost of equity.

In aggregate, these recommendations by Dr. Woolridge and Mr. Gorman would reduce our revenue requirements approximately $54 million. These two recommendations alone would reduce the authorized rate increase to approximately $20 million – or less than 30% of Gulf's need.

Before considering any other intervenor adjustments, Gulf's equity investors would be faced with the prospect of achieving returns of less than 7% on their actual investment in Gulf if these two recommendations were accepted.

Q. Is Mr. Gorman's proposed change to the method to reconcile rate base and capital structure appropriate?

A. No. Mr. Gorman suggests his methodology is necessary to ensure that customers receive the full benefit of no-cost capital. That is not the case. As Gulf Witness Deason discusses in more detail, Mr. Gorman's proposal would inappropriately double count the impact of the no-cost capital. The effect would simply be to unjustly reduce the overall rate of return to investors.

Q. Are the intervenors' recommendations for ROE reasonable?

A. No. Neither OPC's ROE recommendation of 9.0% nor FEA's recommendation of 9.45% would be sufficient for investors. Gulf Witness Vander Weide recommends an ROE of 11.5% and addresses the intervenor recommendations in his rebuttal testimony.

Returns at the levels proposed by the intervenors are not commensurate with companies of comparable risk and would cause Gulf to have the lowest authorized ROE of any of the electric utilities subject to rate and price regulation by this Commission. Those returns would also be among the lowest authorized in the country.

Q. How do the intervenors' recommendations compare with recent decisions by this Commission?

A. Their recommendations are substantially below the 10.25% established for Gulf in our last rate case, the 10.25% recently approved for TECO, the 10.5% approved for FPL, and the 10.5% recently reaffirmed for Progress (now Duke). Approval of their recommendations would cause Gulf's authorized return to be between 80 and 150 basis points lower than those currently authorized for TECO, FPL and Duke.

Such a result is simply unreasonable under the best of circumstances, particularly given the lower equity ratio and greater financial risk in Gulf's capital structure.

Q. How do the intervenors' recommendations compare to other regulatory decisions throughout the country?

A. Accepting Mr. Gorman's recommended ROE of 9.45% would place Gulf amongst the lowest authorized ROEs in the country. Dr. Woolridge's recommendation of 9.0% represents the lowest authorized ROE in the nation over the last two years.

Q. What effect would an authorized ROE in the range of 9.0% to 9.45% have on Gulf?

A. An authorized return at those levels would have seriously adverse impacts on the confidence of both equity and debt investors alike.

Gulf's returns have languished at unacceptable levels, between the mid-single digits and the bottom end of the range of authorized ROE set for Gulf by the Commission since the middle of 2010. The expectations of an improving economy, along with a supportive and constructive regulatory environment, have provided investors with confidence that their investments would yield the required returns in the future. With sales growth at a minimum, forecasts declining with every update and capital investment requirements at all-time highs, investors are depending on the Commission to put Gulf back into position to have an opportunity to provide them with a fair return. Establishing and setting rates based on an ROE at the levels recommended by the intervenors would dim any hopes of earning a fair return in the foreseeable future.

Debt investors, meanwhile, will be looking to the credit rating agencies for reaction to the outcome of our case and implications to Gulf's credit risk. Authorizing an ROE at the levels recommended by the intervenors would not be received well by the credit rating agencies. The utility regulatory environment in Florida has historically been viewed as credit supportive; however, accepting these recommendations would revive recent concerns about the regulatory environment in Florida – concerns that played a primary role in a rating downgrade of Gulf Power in 2010.

After rate case proceedings in 2010 for Gulf's peer utilities in Florida, in its credit opinion of Gulf Power (dated August 13, 2010), Moody's saw "the overall regulatory framework in Florida as substantially less supportive of credit quality" and cited this as a primary factor in downgrading Gulf's credit rating.

The rating agencies' opinions of Florida's regulatory environment have improved over the past couple of years. In its last credit opinion of Gulf dated August 9, 2013, Moody's cited an "improved political and regulatory environment in Florida".

As Gulf Witness Fetter discusses, investors also consider the ratings of state regulatory environments published by Regulatory Research Associates (RRA). After lowering its rating following Commission decisions in 2010, the rating has been upgraded; however, the rating still has not fully recovered from the downgrade during the tumultuous period several years ago.

Notably, the states that have awarded utilities ROEs in the range recommended by Mr. Gorman and Dr. Woolridge are all rated Average to Below Average by RRA.

As evidenced by the weights applied in their assessments and past rating agency actions, the perception of state regulatory environments is critical to the credit quality of utilities. Joining the ranks of those states would bring the supportiveness of the Florida regulatory environment back into question and could result in negative rating actions to not only Gulf but all electric utilities under the Commission's jurisdiction.

Q. Mr. Gorman testified that setting rates based on a 9.45% ROE would be supportive of Gulf's current credit rating. Do you agree with that claim?

A. I do not. As Mr. Fetter explains in more detail, there are at least three problems with Mr. Gorman's contention – he references the wrong credit rating as the basis for his analysis, is grossly simplistic in his assessment, and only considers one agency's rating.

Q. Should the Commission accept the intervenors' recommendations related to ROE and capital structure, or to make other adjustments that would decrease Gulf's rates?

A. Absolutely not. The intervenors' objectives through both their proposals regarding ROE and their other adjustments seem to be simply to set rates as low as possible today, without concern for the impact on customers in the future. In their efforts to meet this objective, the arbitrary nature of proposed disallowances are evidence of a disregard for the expertise of Gulf's employees in determining what is required to provide safe and reliable service to our customers in both the near term and long term.

A Commission order establishing such a low ROE or decreasing rates would be detrimental and potentially devastating to Gulf's ability to access and raise capital on reasonable terms.

Current rates have not allowed Gulf to provide equity investors with fair returns for several years. Gulf's history of providing fair returns is quickly becoming the distant past. Investors' patience is not endless and should not be abused by a continued failure to allow Gulf a reasonable opportunity to earn a fair return on investment capital.

Gulf's credit quality is under pressure. Contrary to Mr. Gorman's claims, our financial metrics will not support our credit ratings if the Commission were to accept his recommendations. Moody's, for example, states clearly that Gulf's "cash flow coverage metrics are weak for its A3 rating". Strong scores on the qualitative factors, specifically Florida's constructive regulatory environment, have been essential to maintaining that rating. Accepting the intervenors' recommendations would not only further weaken Gulf's financial ratios, but as importantly, cause alarm and reignite concerns about the regulatory environment in Florida. Those concerns would certainly affect Gulf and would likely also affect other utilities in Florida.

It is simply unreasonable for anyone to expect that a rate decrease or an unrealistically low ROE could be supportive of Gulf's financial integrity or would be in the best interest of our customers.

Q. Does that conclude your rebuttal testimony?

A. Yes.

Exhibit

Florida Public Service Commission
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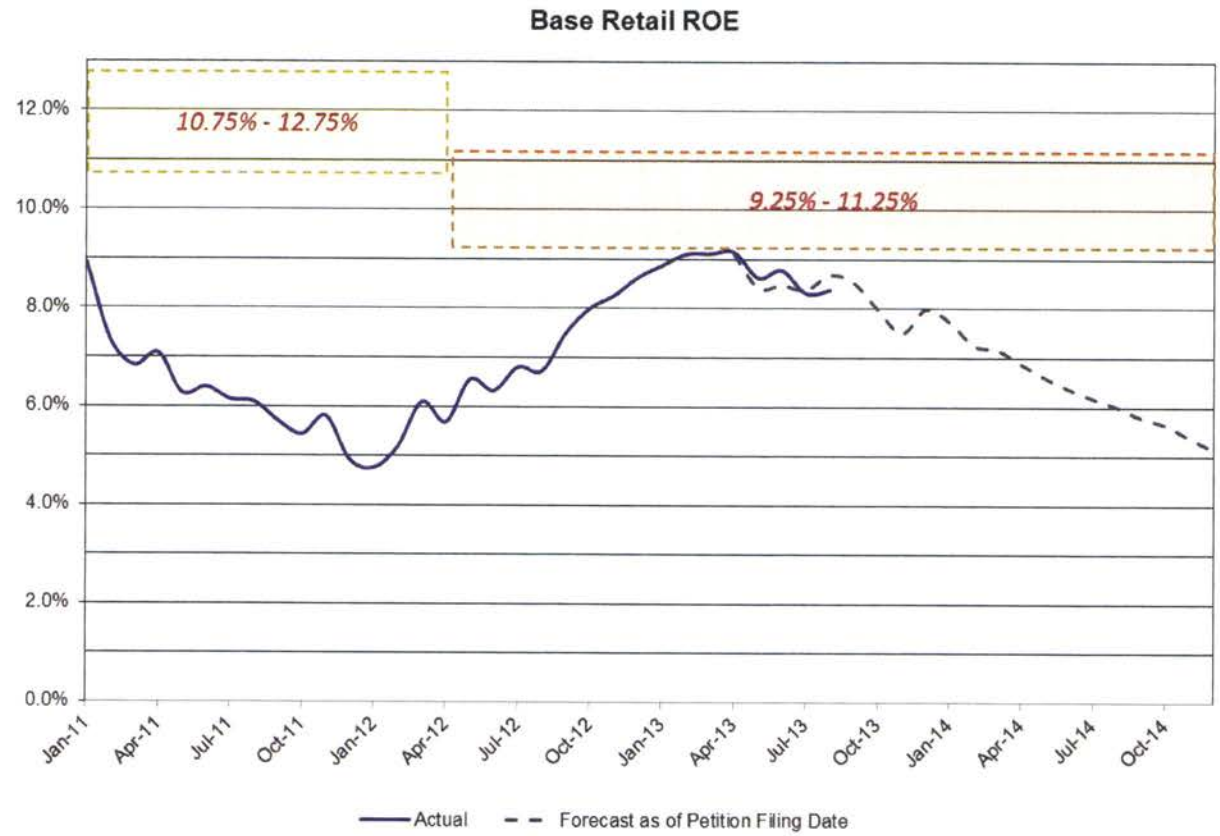

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

JAMES H. VANDER WEIDE, Ph.D.

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
James H. Vander Weide, Ph.D.
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

I. INTRODUCTION AND PURPOSE

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

A. My name is James H. Vander Weide. I am Research Professor of Finance and Economics at Duke University, The Fuqua School of Business. I am also 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. Are you the same James H. Vander Weide who provided direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by Gulf Power Company (Gulf or the Company) to review the direct testimonies and cost of capital recommendations of Dr. J. Randall Woolridge and Mr. Michael P. Gorman. Dr. Woolridge's testimony is presented on behalf of the Florida Office of Public Counsel (OPC), and Mr. Gorman is appearing on behalf of the Federal Executive Agencies (FEA).

Q. Is there anything in the testimonies of Dr. Woolridge and Mr. Gorman that causes you to change your recommended cost of equity for Gulf?
A. No, there is not. I continue to recommend that Gulf be allowed to earn an 11.5 percent rate of return on equity.

Q. Are you sponsoring any rebuttal exhibits?
A. Yes, I am sponsoring Exhibit __ (JVW-3), Schedules 1 to 6. This exhibit was prepared under my direction and control and the information contained therein is true and correct to the best of my knowledge and belief.

II. REBUTTAL OF DR. WOOLRIDGE

Q. What is Dr. Woolridge's recommended rate of return on equity for Gulf?
A. Dr. Woolridge recommends that Gulf be allowed an opportunity to earn a rate of return on equity equal to 9.0 percent (Woolridge at 2 – 3).

Q. What capital structure and senior capital cost rates does Dr. Woolridge recommend for Gulf?
A. Dr. Woolridge adopts the Company's proposed capital structure and senior capital cost rates (Woolridge at 3).

Q. Does Dr. Woolridge also recommend an overall rate of return for investor-supplied capital?
A. Yes. Dr. Woolridge recommends an overall rate of return on investor-

supplied capital equal to 6.86 percent (Woolridge Exhibit__JRW-1).

Q. What areas of Dr. Woolridge's testimony will you address in your rebuttal testimony?

A. I will address Dr. Woolridge's: (1) discounted cash flow (DCF) analysis; (2) Capital Asset Pricing Model (CAPM) analysis; (3) comments on the relationship between utility rates of return on equity and their market-to-book ratios; and (4) comments on my direct testimony.

A. DCF Analysis

Q. What is the DCF model?

A. The DCF model is a model of stock valuation that assumes that a company's stock price is equal to the present discounted value of all expected future dividends investors expect to receive from owning the stock. Assuming that dividends grow at a constant annual rate, *g,* 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. Does Dr. Woolridge use the DCF model to estimate Gulf's cost of equity?

A. Yes, he does.

Q. What cost of equity results does Dr. Woolridge obtain from his application of his DCF model?

A. Dr. Woolridge obtains a cost of equity result of 8.8 percent for his Electric Proxy Group and a DCF result of 9.0 percent for the Vander Weide Proxy Group (Woolridge Exhibit ___JRW-10, page 1 of 10).

Q. What DCF model does Dr. Woolridge use to estimate Gulf's cost of equity?

A. Dr. Woolridge uses an annual DCF model of the form, $k = D_0(1+.5g)/P_0 + g$, where k is the cost of equity, D_0 is the first period dividend, P_0 is the current stock price, and g is the average expected future growth in the company's earnings and dividends.

Q. What are the basic assumptions of Dr. Woolridge's annual DCF model?

A. Dr. Woolridge's annual DCF model is based on the assumptions that: (1) a company's stock price is equal to the present value of the future dividends investors expect to receive from their investment in the company; (2) dividends are paid annually; (3) dividends, earnings, and book values are expected to grow at the same constant rate forever; and (4) the first dividend is received one year from the date of the analysis.

Q. Do you agree with Dr. Woolridge's use of an annual DCF model to estimate Gulf's cost of equity?

A. No. Dr. Woolridge's annual DCF model is based on the assumption that companies pay dividends only at the end of each year. Since Dr. Woolridge's proxy companies all pay dividends quarterly, Dr. Woolridge should have used the quarterly DCF model described in Exhibit ___(JVW-2) Appendix 2 of my direct testimony to estimate Gulf's cost of equity.

Q. Why is it unreasonable to use an annual DCF model to estimate the cost of equity for companies that pay dividends quarterly?

A. It is unreasonable to apply an annual DCF model to companies that pay dividends quarterly because: (1) the DCF model is based on the assumption that a company's stock price is equal to the present value of the expected future dividends associated with investing in the company's stock; and (2) the annual DCF model cannot be derived from this assumption when dividends are paid quarterly. I note that this Commission also uses a quarterly DCF model when estimating the cost of equity for water and wastewater utilities. *See* Order No. PSC-13-0241-PAA-WS issued June 3, 2013, in Docket No. 130006-WS, regarding the annual reestablishment of authorized range of return on common equity for water and wastewater utilities.

Q. Does Dr. Woolridge acknowledge that one must recognize the assumptions of the DCF model when estimating the model's inputs?

A. Yes. Dr. Woolridge states, "In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate)." (Woolridge at 27)

Q. Recognizing your disagreement with Dr. Woolridge's use of an annual DCF model, did Dr. Woolridge apply the annual DCF model correctly?

A. No. Dr. Woolridge's annual DCF model is based on the assumption that dividends will grow at the same constant rate forever. Under the assumption that dividends will grow at the same constant rate forever, the cost of equity is given by the equation, $k = D_0 (1 + g) / P_0 + g$, where D_0 is the current annualized dividend, P_0 is the stock price, and g is the expected constant annual growth rate. Thus, the correct first period dividend in the annual DCF model is the current annualized dividend multiplied by the factor, (1 + growth rate). Instead, Dr. Woolridge uses the current annualized dividend multiplied by the factor (1 + 0.5 times growth rate) as the first period dividend in his DCF model. This incorrect procedure, apart from other errors in his methods, causes him to underestimate Gulf's cost of equity.

Q. Does Dr. Woolridge apply his annual DCF model directly to Gulf?

A. No. Because Gulf's stock is not publicly traded, Dr. Woolridge applies his annual DCF model to two groups of electric utilities, including a group of electric utilities that meet Dr. Woolridge's proxy selection criteria (see Woolridge at 13) and the electric utilities in the comparable group I use to estimate Gulf's cost of equity in my direct testimony.

Q. What data does Dr. Woolridge consider for estimating the dividend yield component of his annual DCF model?

A. Dr. Woolridge considers the average monthly dividend yield for the past six months and dividend yields calculated by dividing the current annual dividend by stock prices over the most recent thirty-day, sixty-day, and ninety-day periods.

Q. What data does Dr. Woolridge consider for estimating the expected future growth component of the DCF cost of equity?

A. Dr. Woolridge considers Value Line data on historical growth rates in earnings, dividends, and book value, as well as Value Line data on projected growth rates in earnings, dividends, and book value. For most of his proxy companies, Value Line's average historical growth rates are significantly less than its projected growth rates. Dr. Woolridge also considers analysts' forecasts of future growth provided by First Call, Reuters, and Zacks, and internal growth estimates based on Value Line's estimates of retention ratios and rates of return on book equity (Woolridge at 36).

Q. Do you agree with Dr. Woolridge's use of historical growth rates to estimate investors' expectation of future growth in the DCF model?

A. No. Historical growth rates are inherently inferior to analysts' growth forecasts because analysts' forecasts already incorporate all relevant information regarding historical growth rates and also incorporate the analysts' knowledge about current conditions and expectations regarding the future. My studies, described in my direct testimony at pp. 27 – 29, indicate that investors use analysts' earnings growth forecasts in making stock buy and sell decisions rather than historical or internal growth rates such as those presented by Dr. Woolridge.

Q. Does Dr. Woolridge recognize the inherent problems in using historical growth rates to estimate investors' expected future growth in the DCF model?

A. Yes. Dr. Woolridge recognizes the inherent problems in using historical growth rates when he states,

> However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations. [Woolridge at 30]

Q. How do Value Line's projected growth rates for Dr. Woolridge's proxy groups of electric utilities compare to Value Line's historical growth rates for these companies?

A. For the Electric Proxy Group, Value Line's projected growth rates are one hundred basis points higher than Value Line's historical growth rates. For the Vander Weide proxy group, Value Line's projected growth rates are 155 basis points higher than Value Line's historical growth rates (see Woolridge Exhibit__JRW-10, pp. 4 - 7).

Q. How do the analysts' growth rates for Dr. Woolridge's groups of proxy companies compare to Value Line's historical growth rates for these companies?

A. For the Electric Proxy Group, the average analysts' growth rate is 125 basis points higher than the average Value Line historical growth rate. For the Vander Weide proxy group, the average analysts' growth rate is 145 basis points higher than the average Value Line historical growth rates (see Woolridge Exhibit__JRW-10, pp. 4, 5, 8, and 9).

Q. What is the internal growth method of estimating the growth component of the DCF cost of equity?

A. The internal growth method estimates expected future growth by multiplying a company's retention ratio, "b," times its expected rate of return on equity, "r." Thus, "g = b x r," where "b" is the percentage of earnings that are retained in the business and "r" is the expected rate of return on equity.

Q. Do you agree with the use of the internal growth method to estimate investors' expected future growth in the DCF model?

A. No. The internal growth method is logically circular because it requires an estimate of the expected rate of return on equity, "r," in order to estimate the cost of equity using the DCF model. Yet, for regulated companies such as Gulf, the allowed rate of return on equity is set equal to the cost of equity.

Q. How does Dr. Woolridge estimate the expected rate of return on equity for each proxy company in his sustainable or internal growth analysis?

A. Dr. Woolridge uses Value Line's forecast of each company's rate of return on equity for the period 2016 – 2018 as his estimate of the expected rate of return on equity for each company.

Q. What rate of return on equity does Dr. Woolridge assume in his calculation of expected growth using his internal growth method?

A. Dr. Woolridge assumes a median rate of return on equity equal to 9.5 percent (see Woolridge Exhibit__JRW-10, p. 6 of 10).

Q. Is it reasonable to assume that Dr. Woolridge's proxy companies will earn a rate of return on equity equal to 9.5 percent when he is recommending that they be allowed to earn only a return of 9.0 percent?

A. No. Investors are well aware that electric utilities are regulated by rate of return regulation. If investors truly believed that the utilities' cost of equity were equal to Dr. Woolridge's recommended 9.0 percent, they would forecast that the utilities would earn 9.0 percent on equity. Thus, Dr. Woolridge's recommended 9.0 percent rate of return on equity is inconsistent with an assumed 9.5 percent earned rate of return on equity for his proxy companies.

Q. Does Dr. Woolridge's internal growth method recognize that, in addition to growth from retained earnings, the companies in his proxy group can also grow by issuing new equity at prices above book value?

A. No. Dr. Woolridge's internal growth method underestimates the expected future growth of his proxy companies because it neglects the possibility that the companies can also grow by issuing new equity at prices above book value. Because many of the proxy companies are selling at prices in excess of book value, and Value Line forecasts that many of them will issue new equity over the next several years, Dr. Woolridge's failure to recognize the "external" component of future growth causes to him to underestimate his proxy companies' expected future growth even more.

Q. Does Dr. Woolridge's internal growth method recognize that Value Line's reported rates of return on equity generally understate each company's average rate of return on equity for the year?

A. No. Dr. Woolridge fails to recognize that Value Line calculates its reported rates of return on equity by dividing a company's net income by end of year equity, whereas most financial analysts calculate a company's rate of return on equity by dividing net income by the average equity for the year. In the general case where a company's equity is increasing, Value Line's reported ROEs will understate the average ROE for the year. Thus Dr. Woolridge's failure to recognize that Value Line's reported ROEs understate each company's average ROE for the year is an additional factor causing him to underestimate Gulf's cost of equity.

Q. Do you agree with Dr. Woolridge's use of analysts' growth forecasts to estimate the expected growth component of his DCF model?

A. Yes. As discussed in my direct testimony, I recommend the use of analysts' growth forecasts to estimate investors' expected growth in the DCF model. The DCF model requires the growth forecasts of investors, and there is considerable empirical evidence that investors use analysts' growth forecasts to estimate future earnings growth (Vander Weide direct at 26 – 29).

B. Capital Asset Pricing Model Analysis

Q. What is the CAPM?

A. The CAPM is an equilibrium model of expected returns on risky securities in which the expected or required return on a given risky security is equal to the risk-free rate of interest plus the security's "beta" times the market risk premium:

Expected return = Risk-free rate + (Security 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 security 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 does Dr. Woolridge use the CAPM to estimate Gulf's cost of equity?

A. The CAPM requires estimates of the risk-free rate, the company-specific risk factor, or beta, and either the required return on an investment in the market portfolio, or the risk premium on the market portfolio compared to an investment in risk-free government securities. For the risk-free rate, Dr. Woolridge uses an average 4.0 percent yield on 30-year Treasury bonds (Woolridge at 39); for the company-specific risk factor or beta, Dr. Woolridge uses the current Value Line beta for each company (Woolridge at 40); and for the required return or risk premium on the market portfolio, Dr. Woolridge employs an average 5.0 percent risk premium he obtains from his review of the risk premium literature (Woolridge at 46).

Q. What CAPM result does Dr. Woolridge obtain for his proxy companies?

A. For the Electric Proxy Group, Dr. Woolridge obtains a CAPM result of 7.5 percent; and for the Vander Weide proxy group, Dr. Woolridge obtains a CAPM result of 7.8 percent (Woolridge at 46).

Q. Does Dr. Woolridge recognize that the result of his CAPM analysis is unreasonably low?

A. Yes. Dr. Woolridge reports results equal to 8.8 percent and 9.0 percent for his DCF studies and results equal to 7.5 percent and 7.8 percent for his CAPM studies (Woolridge at 46). From these results, Dr. Woolridge concludes that Gulf's cost of equity is equal to 9.0 percent. Since Dr. Woolridge's CAPM results are 120 to 150 basis points lower than his recommended cost of equity, Dr. Woolridge must agree that CAPM results of 7.5 percent and 7.8 percent are unreasonably low.

Q. Do you agree with Dr. Woolridge's application of the CAPM?
A. No, but I agree with Dr. Woolridge that his CAPM results are below a reasonable range of estimates of Gulf's cost of equity.

Q. Why do you believe that the CAPM produces unreasonably low cost of equity results for electric utilities at this time?
A. I believe there are two reasons why the CAPM produces unreasonably low cost of equity results for electric utilities at this time. First, as a result of the economic crisis, the U.S. Treasury has kept interest rates on Treasury securities unusually low as part of its effort to stimulate the economy. Economists are forecasting that interest rates on Treasury securities will increase significantly once the economy begins to recover. In addition, the betas of utilities are currently approximately 0.70, and the CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and to overestimate the cost of equity for companies whose equity beta is greater than 1.0.

Q. Did you summarize in your direct testimony the evidence that the CAPM underestimates the required returns for securities or portfolios with betas less than 1.0 and overestimates required returns for securities or portfolios with betas greater than 1.0?
A. Yes. I summarized this evidence in my direct testimony on pages 44 – 47.

Q. What conclusions do you reach from your review of the literature on the CAPM to predict the relationship between risk and return in the marketplace?

A. I conclude that the financial literature strongly supports the proposition that the CAPM underestimates the cost of equity for companies such as public utilities with betas less than 1.0. Since the CAPM significantly underestimates the cost of equity for companies with betas less than 1.0, and both Dr. Woolridge's and my proxy companies have betas that are significantly less than 1.0, I further conclude that the Commission should give little weight to the results of the CAPM at this time.

C. Dr. Woolridge's Comments on the Relationship between Utilities' Rates of Return on Equity and their Market-to-Book Ratios

Q. Does Dr. Woolridge discuss the relationship between rates of return equity, the cost of equity, and market-to-book ratios in his testimony?

A. Yes. Dr. Woolridge asserts that a market-to-book ratio above 1.0 indicates that a company is earning more than its cost of equity:

> As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value. (Woolridge at 19.)

Q. Dr. Woolridge reports the results of three regression analyses that he believes support his claim that: (1) companies with market-to-book ratios greater than 1.0 are earning more than their costs of equity; (2) companies with market-to-book ratios equal to 1.0 are earning their costs of equity; and (3) companies with market-to-book ratios less than 1.0 are earning less than their costs of equity (Woolridge at 19 - 20). Does Dr. Woolridge's regression analysis for his electric utilities provide any support for this claim?

A. No. Dr. Woolridge claims that: (1) the cost of equity for electric utilities like Gulf is 9.0 percent; and (2) companies with ROEs less than the cost of equity will have market-to-book ratios less than 1.0. However, contrary to Dr. Woolridge's hypothesis, the data in his work papers indicate that in Panel A in Exhibit JRW-6, there are nineteen electric utilities with ROEs less than 9.0 percent, and only three of these utilities have market-to-book ratios less than 1.0. Similarly, for the natural gas companies shown in Panel B of Exhibit JRW-6, there are two natural gas utilities with ROEs less than 9 percent, and no company has a market-to-book ratio less than 1.0. With regard to the water utilities in Panel C of Exhibit JRW-6, there are three companies with ROEs less than 9 percent, and these companies have market-to-book ratios equal to approximately 1.6. Thus, Dr. Woolridge's own data contradict his claim that companies earning less than their cost of equity will have market-to-book ratios of less than 1.0.

Q. What is the date of Dr. Woolridge's market-to-book study?

A. According to his work papers, Dr. Woolridge's market-to-book study is dated May 2012.

Q. Have you updated Dr. Woolridge's market-to-book study using current market data?

A. Yes. Using current Value Line data at October 2013, I find that of the forty-eight electric utilities followed by Value Line, eighteen have estimated ROEs below Dr. Woolridge's recommended 9.0 percent rate of return on equity. However, contrary to Dr. Woolridge's hypothesis, only one of these eighteen electric utilities has a market-to-book ratio less than 1.0. With regard to the Value Line natural gas utilities, only four of the eleven utilities have estimated ROEs less than 9.0 percent, and no natural gas utility has a market-to-book ratio less than 1.0. Similarly, for the eight water utilities followed by Value Line, there are four companies that have estimated ROEs less than Dr. Woolridge's 9.0 percent recommended return on equity; and no water utility has a market-to-book ratio less than 1.0. These data provide strong evidence that Dr. Woolridge's hypothesis regarding the relationship between ROEs and market-to-book ratios is incorrect.

D. Rebuttal of Dr. Woolridge's Comments on Vander Weide Direct Testimony

Q. What issues does Dr. Woolridge have regarding your estimate of Gulf's cost of equity?

A. Dr. Woolridge disagrees with my: (1) quarterly DCF model; (2) reliance on analysts' growth forecasts; (3) risk premium estimates; (4) allowance for flotation costs; and (5) financial leverage adjustment (Woolridge at 51).

1. Quarterly DCF Model

Q. What are Dr. Woolridge's criticisms of your DCF studies?

A. Dr. Woolridge claims that I should: (1) use the annual rather than the quarterly DCF model to estimate Gulf's cost of equity; (2) use a combination of historical and analysts' growth rates to estimate the growth component of the DCF model; (3) make no allowance for flotation costs; and (4) make no adjustment for the difference between the financial risk reflected in my cost of equity estimate and the financial risk reflected in Gulf's rate making capital structure.

Q. What is the major difference between the quarterly DCF model which you use and the annual DCF model employed by Dr. Woolridge?

A. The major difference is that my quarterly DCF model is based on the realistic assumption that dividends are paid quarterly, while Dr. Woolridge's annual DCF model is based on the unrealistic assumption that dividends are paid once at the end of each year.

Q. Why do you use the quarterly rather than the annual DCF model to estimate Gulf's cost of equity?

A. As I discuss in my direct testimony, the DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. Since the companies in my proxy 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 must 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 discounted value of a quarterly stream of dividend payments. The annual DCF model is only a correct expression for the present discounted value of future dividends if dividends are paid once at the end of each year.

Q. Why does Dr. Woolridge disagree with your application of the quarterly DCF model?

A. Dr. Woolridge argues first that an early proponent of the DCF model, Dr. Myron Gordon, stated that the dividend yield component of the DCF model should be calculated by: "(1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price" (Woolridge at 28). Second, Dr. Woolridge argues that my quarterly DCF model allows investors to earn more than their required rate of return on equity (Woolridge at 53).

Q. Is Dr. Gordon's statement in favor of an annual DCF model a reasonable justification for use of the annual DCF model in this proceeding?

A. No. Although Dr. Gordon was certainly a major early proponent of the DCF model, this does not imply that Dr. Gordon is correct in his arguments regarding the quarterly DCF model. As shown in Appendix 2 of Exhibit ___ (JVW-2) to my direct testimony, there can be no doubt that when dividends are paid quarterly, the quarterly DCF model must be used to estimate the cost of equity.

Q. Do you agree with Dr. Woolridge's assertion that the quarterly DCF model allows investors to earn more than their required return on equity?

A. No. The quarterly DCF model does not allow investors to earn more than their required return on equity; it simply offers a better estimate of investors' required return on equity than an annual DCF model. Whether a company earns more than its cost of equity depends on many factors, including the state of the economy and the demand for electricity, factors which cannot be known at the time the cost of equity is being estimated.

2. Analysts' Growth Forecasts

Q. Dr. Woolridge also criticizes your use of analysts' growth rates in your DCF model. Why do you use analysts' growth rates to estimate the growth component of the DCF model?

A. I use analysts' growth rates because my studies indicate that the analysts' growth rates are highly correlated with stock prices. This evidence provides strong support for the conclusion that investors use analysts' growth rates in making stock buy and sell decisions, and thus the analysts' growth rates should be used to estimate the growth component of the DCF model.

Q. Does Dr. Woolridge agree with your statistical studies of the relationship between analysts' growth rates and stock prices?

A. No. Dr. Woolridge has four criticisms of my statistical studies of the relationship between analysts' growth rates and stock prices. First, he argues that my statistical study is outdated. Second, he argues that my study is misspecified because I used a "linear approximation" to the DCF model rather than a modified version of the DCF model. Third, he argues that I did not use both historical and analysts' forecasted growth rates in the same regression. Fourth, he argues that I did not perform any tests to determine if the difference between historic and projected growth measures is statistically significant (Woolridge at 56 – 57).

Q. Do you agree with Dr. Woolridge's assertion that your statistical analysis of the relationship between analysts' growth rates and stock prices is outdated?

A. No. As discussed in my direct testimony, my study was updated in August 2004. The updated study continues to support the conclusion that the analysts' growth rates are more highly correlated with stock prices than historical measures such as those employed by Dr. Woolridge. Furthermore, Dr. Woolridge ignores other studies that have corroborated my results.

Q. Do you agree with Dr. Woolridge's criticism that your DCF model is misspecified because you used a "linear approximation" to the DCF model rather than a modified version of the DCF model?

A. No. Most regression analyses are based on the assumption that the relationship between the variables being studied is linear. As part of my studies, I tested whether the linear assumption was sufficiently close to provide reliable estimates of the model parameters. Applying a first order Taylor-series approximation to the DCF equation, I found that the first order, or linear, approximation was sufficiently close to the true equation to justify using linear regression analysis to study the relationship between price/earnings ratios and growth rates.

Q. Why did you not use a combination of historical and analysts' growth rates in the same regression?

A. I did not use a combination of historical and analysts' growth rates in the same regression because there are an infinite number of such combinations which could be tested. My studies indicate that the relationship between analysts' growth forecasts and stock prices is so strong compared to the relationship between historical growth rates and stock prices that there would be little advantage to combining historical growth rates with analysts' forecasts to predict stock prices.

Q. Is there a statistically significant difference between historical and projected growth measures in explaining stock prices in your statistical study?

A. Yes. The difference in performance of historical and projected growth rates is both statistically significant and dramatic.

Q. Dr. Woolridge claims in his testimony, "it is well known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased." (Woolridge at 33.) Is he correct?

A. No. Contrary to Dr. Woolridge's claim, the academic literature presents compelling evidence that analysts' EPS growth forecasts are unbiased—that is, neither optimistic nor pessimistic. I have reviewed nine articles that address whether analysts' growth forecasts are overly optimistic. At least seven of the nine articles reviewed find no evidence that analysts' growth forecasts are overly optimistic. Two find evidence of optimism in the early years of the study, but also conclude that optimism is not present in the later years of the study. In fact, one study finds that analysts' forecasts for the S&P 500 are pessimistic for the last four years of the study (see Table 1 and Schedule 1 of Exhibit JVW-3).

TABLE 1

ARTICLES THAT STUDY WHETHER ANALYSTS' FORECASTS ARE BIASED TOWARD OPTIMISM

Author (Date)	*Conclusion*
Crichfield, Dyckman, and Lakonishok (1978)	Unbiased
Elton, Gruber, and Gultekin (1984)	Unbiased
Givoly and Lakonishok (1984)	Unbiased
Brown (1997)	Declining optimism
Keane and Runkle (1998)	Unbiased
Abarbanell and Lehavy (2003)	Unbiased
Ciccone (2005)	Pessimistic
Clarke, Ferris, Jayaraman, and Lee (2006)	Unbiased
Yang and Mensah (2006)	Unbiased

Q. Does some of the later research explain why some earlier studies in the literature conclude that analysts' EPS growth forecasts are optimistic?

A. Yes. Articles by Abarbanell and Lehavy (2003) and Keane and Runkle (1998) recognize that the results of earlier studies are heavily influenced by:

(i) the inclusion of large unexpected accounting write-offs and special accounting charges in reported earnings; and (ii) the impact of high correlation in analysts' forecasts. These articles conclude that once the statistical problems associated with the inclusion of non-recurring earnings in reported earnings per share and correlations in analysts' forecasts are corrected, the evidence supports the conclusion that analysts' forecasts are unbiased, and hence, not optimistic.

Q. Dr. Woolridge discusses the results of his study of the relationship between analysts' forecasts for utilities and the utilities' subsequent achieved earnings growth rates. Do you have any comments on his study?

A. Yes. First, Dr. Woolridge has misspecified the time frame of his analysts' earnings growth forecasts. In his study, Dr. Woolridge claims that he compares the analysts' forecast made in a particular quarter to the company's realized earnings growth rate in the *same* quarter four years hence. In making this comparison, Dr. Woolridge fails to recognize that: (1) the time frame of the analysts' growth forecast is an indefinite, long-run period that may differ from one analyst to another; (2) quarterly realized earnings are unaudited; and (3) quarterly realized earnings are subject to seasonality. Dr. Woolridge has provided no evidence that analysts' growth estimates were intended to forecast actual results for exactly the same quarter four years hence.

Second, Dr. Woolridge has not distinguished between recurring (that is, normalized) and non-recurring (that is, non-normalized) earnings. The analysts' forecasts are intended to be applied only to growth in recurring earnings, meaning that they are forecasts of earnings in the absence of extraordinary events and one-time write-offs. It is likely that the forecast deviations in Dr. Woolridge's sample are due primarily to the impact of extraordinary events and one-time write-offs rather than to problems with the analysts' forecasts of recurring earnings.

Third, Dr. Woolridge fails to adjust for the high correlation in analysts' forecasts across companies. Financial researchers have conclusively demonstrated that there is no evidence of analysts' optimism in data sets that are properly adjusted for the impact of one-time accounting write-offs and the correlation in analysts' forecasts across companies. (*See* Jeffery Abarbanell and Reuven Lehavy, "Biased Forecasts or Biased Earnings? The Role of Reported Earnings in Explaining Apparent Bias and Over/underreaction in Analysts' Earnings Forecasts," *Journal of Accounting and Economics,* 36 (2003) 105 – 146; Stephen J. Ciccone, "Trends in Analyst Earnings Forecast Properties," *International Review of Financial Analysis*, 14 (2005) 1 – 22.)

Q. Why do analysts exclude non-recurring earnings from earnings growth forecasts?

A. Analysts exclude non-recurring earnings from earnings growth forecasts because stock prices reflect the impact of expected future earnings and, by definition, non-recurring earnings or losses are not expected to recur in the future. Since non-recurring earnings do not, in theory, impact stock prices, analysts do not include them in their earnings per share forecasts. In addition, because accounting adjustments are somewhat discretionary, it is virtually impossible to forecast the timing and magnitude of such adjustments, certainly when the long-term earnings per share forecast is intended to apply to a period three to five years in the future.

Q. Do you have evidence that non-recurring items can have a significant impact on the reported earnings per share for electric utilities?

A. Yes. The impact of non-recurring items on reported earnings per share for electric utilities can be estimated from annual data on aggregate earnings per share for electric utilities, including and excluding non-recurring items, published by The Edison Electric Institute in its annual financial report on investor-owned electric utilities. As shown in Table 2 below, aggregate EPS including non-recurring items (that is, EPS as reported) is generally less than aggregate EPS excluding non-recurring items; and, in many years, the difference is substantial. Thus, Dr. Woolridge's use of EPS data that include non-recurring items could have had a significant impact on his conclusion that analysts' forecasts are optimistic.

TABLE 1

EARNINGS PER SHARE ("EPS") INCLUDING AND EXCLUDING NON-RECURRING ITEMS

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

1992 - 2007

Year	EPS Include Non-Recurring	EPS Exclude Non-Recurring	Difference (Exclude – Include)
1992	1.66	1.85	0.19
1993	1.65	1.99	0.34
1994	1.92	1.96	0.04
1995	2.10	2.11	0.01
1996	2.14	2.21	0.07
1997	1.49	2.01	0.52
1998	1.52	1.79	0.27
1999	2.04	2.05	0.01
2000	1.59	2.47	0.88
2001	2.43	2.93	0.50
2002	(0.04)	2.40	2.44
2003	1.45	2.20	0.75
2004	2.23	2.00	(0.23)
2005	2.09	2.28	0.19
2006	2.42	2.37	(0.05)
2007	2.65	2.34	(0.31)

3. Risk Premium

Q. What is the risk premium approach to estimating the cost of equity?

A. The risk premium approach is based on the principle that investors expect to earn a return on an equity investment in Gulf that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of long-term bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments. Using the risk premium approach, the cost of equity is given by the following equation: cost of equity = interest rate plus risk premium.

Q. How do you estimate the interest rate component of the risk premium approach?

A. I estimate the interest rate component of the risk premium approach using the yield to maturity on A-rated utility bonds.

Q. Does Dr. Woolridge have any criticisms of your use of the yield to maturity on A-rated utility bonds to estimate the interest rate component of the risk premium approach?

A. Yes. Dr. Woolridge argues that my use of the yield to maturity on A-rated utility bonds inflates the required return on equity because long-term utility bonds are not risk free, that is, they are subject to both interest rate risk and credit risk (Woolridge at 59).

Q. Do you agree with Dr. Woolridge's criticism of your use of the yield to maturity on A-rated utility bonds to estimate the interest rate component of the risk premium approach?

A. No. Dr. Woolridge fails to recognize that the risk premium approach does not require that the interest rate be "risk free." Indeed, the only requirement of the risk premium approach is that the same interest rate be used to estimate the interest rate component as is used to estimate the risk premium component. Since the risk premium approach suggests that the cost of equity equals (the interest rate) plus (the required return on equity minus the interest rate), the cost of equity should be approximately the same in a risk premium analysis, no matter what interest rate is used as the benchmark interest rate. Thus, use of the interest rate on A-rated utility bonds in a risk premium analysis will produce a higher interest rate component than use of a government bond interest rate, but this difference will be offset by the correspondingly lower risk premium. The lower risk premium arises because the difference between the return on equity and yield on A-rated utility bonds is less than the difference between the return on equity and the yield on long-term government bonds.

Q. Why do you use the yield on A-rated utility bonds rather than the yield on Treasury bonds in your risk premium studies?

A. I use the yield on A-rated utility bonds rather than the yield on Treasury bonds in my risk premium studies because I believe that utility bond yields are better indicators of utilities' cost of equity than Treasury bond yields. First, because the U.S. dollar is the major currency for international trade, foreign governments tend to hold their currency reserves in U.S. Treasury bonds. Thus, Treasury bond yields are highly sensitive to changes in international economic conditions, whereas the U.S. utilities' cost of equity is not.

Second, since U.S. Treasuries are considered to be the safest investment in the world, investors across the world tend to flock to investments in U.S. Treasuries at times of widespread global economic turmoil. In periods of turmoil, the required return on risky investments such as utility bonds and stocks increases while the yield on U.S. Treasury bonds declines. Thus, changes to U.S. Treasury bond yields are poor indicators of changes in a utility's cost of equity.

Third, yields on U.S. Treasury bonds are highly sensitive to efforts by the Federal Reserve to stimulate the economy. Although most Federal Reserve monetary policy operations are conducted using short-term U. S. Treasury bills, yields on long-term Treasury bonds frequently move in the same direction as yields on short-term Treasury bills. In addition, the Federal Reserve continues to purchase $80 billion per month of mortgage securities and long-term Treasury bonds in an effort to stimulate the economy by reducing long-term Treasury yields.

Fourth, to the extent that there are economic developments that are specific to the utility industry, such as changes in environmental regulations and energy policy, such factors will be reflected both in utility bond yields and the utility cost of equity, but not in U.S. Treasury bond yields. Thus, that utility bond yields reflect utility-specific risks is an argument for—not an argument against—the use of utility bond yields to indicate changes in the utility cost of equity.

Q. How do you estimate the risk premium component of the risk premium approach?

A. I estimate the risk premium component of the risk premium approach in two ways. First, I estimate the difference between the DCF cost of equity for a proxy group of companies over the previous 162 months and the concurrent yield to maturity on A-rated utility bonds in those months, and then adjust the average risk premium to account for changes in interest rates. This estimate is my "ex ante risk premium approach." Second, I estimate the risk premium from an historical study of stock and bond returns over the period 1937 to the present. This second risk premium approach is my "ex post risk premium approach."

Q. Why does Dr. Woolridge criticize your ex ante risk premium approach?

A. Dr. Woolridge criticizes my ex ante risk premium approach because it relies on analysts' forecasts to estimate the required return on equity using the DCF model.

Q. Have you addressed Dr. Woolridge's criticisms of your use of analysts' growth forecasts elsewhere in this rebuttal testimony?

A. Yes, I have. (See Section II, D., 2, above.)

Q. Does Dr. Woolridge agree with your use of historical stock and bond returns to estimate the equity risk premium?

A. No. Dr. Woolridge states:

> There are a number of issues in using historic returns over long time periods to estimate expected equity risk premiums. These issues include: (A) biased historic bond returns; (B) use of the arithmetic versus the geometric mean return; (C) the large error in measuring the equity risk premium using historical returns; (D) unattainable and biased historic stock returns; (E) company survivorship bias; (F) the "peso problem"—U.S. stock market survivorship bias. (Exhibit JRW_16, Appendix D, p. 1)

Q. Why does Dr. Woolridge believe that historical bond returns are biased?

A. Dr. Woolridge states:

> Historic bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards. (Exhibit JRW_16, Appendix D, p. 2)

Q. Do you agree with Dr. Woolridge's statement that historical bond returns are biased downward because of capital losses suffered by past bond investors?

A. No. Because of capital gains and losses, historical bond returns may be higher or lower than what investors expected at the time they purchased the bonds. During the period since 1982, for example, historical bond returns have been biased upward as a measure of expectancy because of the large capital gains achieved by bondholders over this period. However, over the entire period considered in my ex post risk premium study (from 1937 to the present), capital gains and losses on bonds have approximately offset each other, and consequently there is no significant bias as a result from either capital gains or losses.

Q. What is the difference between an arithmetic and a geometric mean return?

A. An arithmetic mean return is an additive return that is calculated by summing the achieved return in each time period and dividing the total by the number of periods. In contrast, the geometric mean return is a multiplicative return that is calculated in two steps. First, one calculates the product of (1 plus the return) in each period of the study. Second, one calculates the n^{th} root of this product and subtracts 1 from the result. Thus, if there are two periods, and r_1 and r_2 are the returns in periods one and two, respectively, the arithmetic mean is calculated from the equation: $a_m = (r_1 + r_2) \div 2$. The geometric mean is calculated from the equation,

$$a_g = [(1 + r_1) \times (1 + r_2)]^{.5} - 1.$$

Q. Please describe Dr. Woolridge's concern regarding the use of arithmetic versus geometric mean returns.

A. Dr. Woolridge believes that my ex post risk premium study is biased because I calculate the expected risk premium using the arithmetic mean of past returns, whereas he believes I should have calculated the expected risk premium using the geometric mean of past returns.

Q. Is Dr. Woolridge's criticism valid?

A. No. As explained in Ibbotson® SBBI® Valuation Edition 2013 Yearbook (SBBI®), the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return. (SBBI® at 56)

A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in my direct testimony, Schedule 5 of Exhibit ___ (JVW-1), "Using the Arithmetic Mean to Estimate the Cost of Equity Capital."

Q. Dr. Woolridge claims that the SEC "requires equity mutual funds to report historical return performance using geometric mean and not arithmetic mean returns." (Woolridge Exhibit JRW_16, Appendix D, p. 3) Does this observation demonstrate that the risk premium should be estimated using geometric mean returns rather than arithmetic mean returns?

A. No. As I discuss above, I agree that historical performance should be measured using the geometric mean rather than the arithmetic mean. However, as I demonstrate in Schedule 5 of Exhibit ___ (JVW-1), in estimating the cost of equity, it is essential to use the arithmetic mean return because it is only the arithmetic mean return that will make an initial investment grow to the expected value of the investment at the end of the investment horizon. Thus, for an investment with an uncertain outcome, the arithmetic mean is the best measure of the forward looking expected risk premium.

Q. Dr. Woolridge also criticizes your ex post risk premium study because it is based on "unattainable and biased historic stock returns." (Woolridge Exhibit JRW_16, Appendix D, p. 5) Is he correct?

A. No. Dr. Woolridge bases his allegation on the assumption that stock index returns such as those reported by Ibbotson® SBBI® are "unattainable to investors." Dr. Woolridge's assumption is false: investors, in fact, can attain the returns achieved by stock indices simply by purchasing the stock index.

Q. Do you agree with Dr. Woolridge's criticism that your ex post risk premium study is characterized by "survivorship bias"? (Woolridge Exhibit JRW_16, Appendix D, pp. 5 - 6)

A. No. Survivorship bias refers to problems that might arise when data for companies that have failed are excluded from the sample. However, with regard to the U.S. markets that I study, survivorship bias is not a major issue. First, over the period 1937 to the present, there have been relatively few companies in the S&P 500 and the S&P Utilities that have failed. Second, the S&P 500 includes the return on a stock until the day it is dropped from the index, and the effect of a company being dropped from the S&P 500 is generally anticipated by the market well in advance of the delisting. Thus, survivorship is not a material issue with respect to U.S. stocks.

Q. What does Dr. Woolridge mean when he refers to the "peso problem"? (Woolridge Exhibit JRW_16, Appendix D, pp. 6 - 7)

A. Dr. Woolridge uses the term "peso problem" to refer to the fact that U.S. investors have earned higher returns on stock investments than investors in other countries because the U.S. economy has not suffered many of the same economic calamities as the economies of other countries. This criticism of the use of U. S. stock returns in risk premium studies might be appropriate if one were attempting to estimate the expected rates of return on non-U. S. stocks. However, for U. S. stocks, since there is no indication that the U. S. will suffer the economic calamities of other countries, such as hyper-inflation or military invasion, there is no reason why the returns on

U. S. stocks would be biased upward. As Morningstar states with respect to "survivorship bias" and the closely-related "peso problem":

> While the survivorship bias evidence may be compelling on a worldwide basis, one can question its relevance to a purely U.S. analysis. If the entity being valued is a U.S. company, then the relevant data set should be the performance of equities in the U.S. market. (SBBI® at 62)

Q. Dr. Woolridge claims that his market risk premium estimate is reasonable because it is consistent with the 6.15 percent long-term forecasted return on the S&P 500 published by the Federal Reserve Bank of Philadelphia's Survey of Professional Forecasters (Woolridge at 66 - 67). Is the Survey of Professional Forecasters a reliable source of cost of equity estimates?

A. No. The economists included in the survey are macro economists who are primarily concerned with forecasting factors such as GDP growth, inflation rates, unemployment rates, job growth, and other macro-economic indicators. They are not experts in forecasting the rate of return on the S&P 500.

Q. Dr. Woolridge also claims that his risk premium estimate is reasonable because it is consistent with the risk premium estimate found in the Graham Harvey survey of Chief Financial Officers in June 2013 (Woolridge at 66). Do you agree that surveys of business managers provide useful information on the expected market risk premium?

A. No. Surveys of business managers provide little or no information on the expected market risk premium because: (1) managers have no incentive to take the survey seriously; (2) their responses are not typically based on market transactions or actual investment decisions; (3) their responses may reflect what they think the investigator wants to hear; and (4) the response rate is frequently low. In addition, Dr. Woolridge fails to recognize that Graham and Harvey comment that their survey responders frequently use hurdle rates for making investment decisions that exceed their estimates of excess returns on the S&P 500. (Graham and Harvey confirm that CEO responses to their survey are not typically based on market transactions or actual investment decisions when they state, "Often their [the CFO's] 10-year risk premium is supplemented so that the company's hurdle rate exceeds their expected excess return on the S&P 500." John Graham and Campbell Harvey, "The Long-Run Equity Risk Premium," Sep. 9, 2005, p. 6.)

4. Flotation Costs

Q. Why do you include an adjustment for flotation costs in your DCF analysis?

A. I include an adjustment for flotation costs because, without such an adjustment, Gulf would not be able to recover all the costs it incurs to finance its investments in electric plant and equipment.

Q. Does Gulf issue equity in the capital markets?

A. No. Although Gulf does not issue equity in the capital markets, its parent must issue equity to provide Gulf the necessary financing to make investments in its electric utility operations in Florida. If the parent is not able to recover its flotation costs through Gulf's rates, it will not be able to recover the full cost of issuing equity required to invest in Gulf.

Q. Does Dr. Woolridge agree with your flotation cost adjustment?

A. No. Dr. Woolridge claims that a flotation cost adjustment is inappropriate because: (1) the company has not presented any evidence that it actually incurs flotation costs when it issues new equity; and (2) it is frequently asserted that a flotation cost adjustment is required to prevent dilution of the company's existing shareholders, but existing shareholders cannot suffer dilution as long as the company's stock price is above book value.

Q. Do you agree with Dr. Woolridge's assertion that the company did not provide any evidence that it incurs flotation costs when it issues new equity?

A. No. In Appendix 3 of Exhibit ___ (JVW-2) to my direct testimony, I present evidence that all companies incur flotation costs when they issue new equity securities, that flotation costs represent approximately five percent of the company's pre-issue stock price, and that the company will not be able to earn a fair rate of return on its investment if it does not recover its flotation costs.

Q. Do you justify flotation costs on the grounds that flotation costs are required to prevent dilution of existing shareholders?

A. No. I justify flotation costs on the grounds that the company will not be able to earn a fair rate of return if it does not recover the flotation costs it incurs when it issues new equity. My flotation cost adjustment is unrelated to the company's market-to-book ratio.

Q. Has the Commission previously accepted a flotation cost allowance for Florida utilities?

A. Yes. For example, the Commission included an adjustment for flotation costs in its 2009 TECO Order. The Commission states, "We have traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor-required ROE. ... such adjustments have typically been on the order of 25 to 50 basis points." (Order No. PSC-09-0283-FOF-EI, Docket No. 080317-EI, April 30, 2009, at 44.) In addition, I note that this Commission typically uses a flotation cost allowance of four percent in both DCF and CAPM models to estimate the cost of equity for water utilities in Florida. (*See* Order No. PSC-13-0241-PAA-WS, issued June 3, 2013 in Docket No. 130006-WS, regarding the annual reestablishment of authorized range of return on common equity for water and wastewater utilities.)

5. Financial Risk Adjustment

Q. How do financial market participants measure risk?

A. Under the assumption that the probability distribution of returns is symmetric, *i.e.*, centered on the mean return, financial market participants generally measure risk by the forward-looking variance of return on investment.

Q. Does the forward-looking variance of an investor's return on a stock investment in a company depend on the company's capital structure?

A. Yes. The forward-looking variance of an investor's return depends on the company's debt to equity ratio, where both debt and equity are measured in terms of market values, not book values.

Q. What is the meaning of the term, "financial risk"?

A. Economists use the term, "financial risk" to refer to the contribution of the firm's capital structure , *i.e.*, its debt to equity ratio, to the forward-looking variance of return on the firm's stock.

Q. Does financial risk reflect the market values of debt and equity in a company's capital structure or the book values of debt and equity in a company's capital structure?

A. Financial risk measures the contribution of the company's capital structure to the forward-looking variance of return on the company's stock, and the forward-looking variance depends on the market values of debt and equity in the company's capital structure, not the book values. (*See,* for example, Richard A. Brealey, Stewart C. Myers, and Franklin Allen, Principles of Corporate Finance, 8^{th} ed., McGraw-Hill, 2006, pp. 452 - 456.) Thus, financial risk reflects the market values of debt and equity in a company's capital structure, not the book values.

Q. Is Gulf recommending that its weighted average cost of capital in this proceeding be calculated based on the market values of debt and equity in its capital structure?

A. No. Consistent with previous regulatory practice, Gulf is recommending that its weighted average cost of capital be based on the book values of debt and equity in its capital structure.

Q. Is the financial risk associated with Gulf's recommended capital structure measured in the same way as the financial risk associated with the capital structures of your proxy companies?

A. No. The financial risk of my proxy companies is reflected in their market value capital structures, while Gulf is recommending that a book value capital structure be used for the purpose of setting rates. Thus, the financial risk of my proxy companies is measured by their market value capital structures, while Gulf's financial risk is measured by its book value capital structure.

Q. How do you adjust your cost of equity results for your comparable companies to reflect the difference between the market's perception of the financial risk of your proxy companies and the financial risk reflected in Gulf's recommended capital structure?

A. As described in my direct testimony (see pp. 51 – 52), I adjust the cost of equity results for my comparable companies by equating the after-tax weighted average cost of capital of my proxy companies to the after-tax weighted average cost of capital of Gulf. In this procedure, I use market-value capital structure weights for my comparable companies because the cost of capital for these companies is based on market values, and I use book value weights for Gulf because the recommended cost of capital for Gulf in this proceeding is based on book values.

Q. Does Dr. Woolridge agree with your financial risk adjustment?

A. No. Dr. Woolridge claims that my financial risk adjustment is unjustified because: (1) a market-to-book ratio above 1.0 indicates that a company is earning more than its cost of equity; (2) there is no change in the company's leverage; (3) financial publications report capital structures based on book values; (4) no other commissions have accepted using a market value capital structure to calculate the allowed rate of return; (5) Gulf's common equity ratio is in line with the common equity ratios of other utilities; and (6) Gulf's bond ratings suggest that Gulf's investor risk is at or lower than that of other electric utilities (Woolridge at 69 – 70).

Q. Do you agree that a market-to-book ratio greater than 1.0 indicates that a company is earning more than its cost of equity?

A. No. As discussed above, Dr. Woolridge's own study, based on May 2012 data, demonstrates that many electric, natural gas, and water utilities have estimated ROEs less than nine percent but also have market-to-book ratios greater than 1.0. His data clearly contradict Dr. Woolridge's claim that a company's market-to-book ratio is an indicator of whether a company is earning more than its cost of equity.

Q. Does your financial risk adjustment assume a "change" in a company's leverage?

A. No. As discussed above, my financial risk adjustment reflects the difference in the financial risk between the capital structures of the proxy companies and the company's ratemaking capital structure. It is unclear what Dr. Woolridge refers to when he notes a "change" in capital structure.

Q. Does the observation that financial publications report capitalization on a book value basis undermine the validity of your financial risk adjustment?

A. No. The validity of my financial risk adjustment is based on the widely-recognized observation that the equity investor measures financial risk by the variance of portfolio return; and the variance of an investor's portfolio return depends on the *market values* of the securities in the portfolio, not on the *book values* of the securities in the portfolio. The truth of the statement that variance of return depends on market values is recognized both in academia and the marketplace. In addition, investors have no difficulty in calculating market value capital structures from publicly available information.

Q. Dr. Woolridge claims that in response to OPC interrogatory No. 68, you state that you "could not identify any proceeding" in which you have testified "where the regulatory commission had adopted" your "leverage adjustment." (Woolridge at 70) Does Dr. Woolridge correctly characterize your response?

A. No. I stated that I do not maintain records of regulatory decisions or a list of all cases in which commissions have accepted my recommendations.

However, I noted that I was generally aware that financial adjustments similar to that which I propose have been adopted in Pennsylvania and Canada, and that many states use market value capital structures to determine utility property taxes.

Furthermore, I am also aware that market value capital structures have been used to set allowed rates of return in numerous telecommunications cases in which I have participated since 1996, including the *Virginia Arbitration Proceeding* in which my 12.95 percent overall cost of capital recommendation was accepted, and a Michigan docket in which my 75 percent equity market value capital structure recommendation has been accepted. (Memorandum Opinion and Order, *Petition of AT&T Communications of Virginia Inc., Pursuant to Section 252(e)(5) of the Communications Act for Preemption of the Jurisdiction of the Virginia Corporation Commission Regarding Interconnection Disputes With Verizon Virginia Inc.*, 18 FCC Rcd 17722 ¶ 94 (2003) ("*Virginia Arbitration Order*"). In this proceeding, the Wireline Competition Bureau of the FCC, accepting Verizon's proposal, finds that the appropriate capital structure component of the weighted average cost of capital should be based on the market values of debt and equity, stating, "we give no weight to the portion of AT&T/WorldCom's proposal that is based on incumbent LECs' book value capital structure." *See* Order at ¶¶ 103-104. See also, Michigan Public Service Commission Order, *In the matter, on the Commission's own motion, to review the total element long run incremental costs and the total service long run incremental costs for Verizon North Inc., and Contel of the South,* *Inc., D/B/A Verizon North Systems, to provide telecommunications services*, Case No. U-15210, March 18, 2009. "The Commission is not persuaded that Verizon's capital structure should be based on book value. The Commission agrees with the Staff and adopts Verizon's proposed capital structure of 75% equity and 25% debt." Order at 17.)

Q. Dr. Woolridge claims that investment risk is measured by bond ratings, and Gulf's bond rating indicates that Gulf's "investment risk is at or below that of other electric utilities." (Woolridge at 70; also see Woolridge at 14) Does a bond rating measure investment risk from the point of view of an equity investor?

A. No. Bond ratings reflect investment risk only from the point of view of debt investors, not the point of view of equity investors.

Q. How does the debt investor's view of risk differ from the equity investor's view of risk?

A. The debt investor's view of risk differs from the equity investor's view of risk in two ways. Debt investors are senior to equity investors in the event of financial distress. That is, debt investors are entitled to repayment of their investment before equity investors get anything. This inherently differentiates debt investors' risk perceptions from the perceptions of equity investors. Because of this, debt investors are primarily concerned with the risk that a company will not be able to repay the interest and principal on its debt, whereas equity investors are primarily concerned with the forward-looking variance of return on their equity investment.

Q. Does the risk that a company will be unable to repay the interest and principal on its debt depend on the market values of the company's debt and equity or on the book values of the company's debt and equity?

A. Because the interest and principal on a company's debt is based on the book value of a company's debt, the probability of bankruptcy depends on the book value of a company's debt in relation to the book value of a company's equity; that is, the probability of bankruptcy depends on a company's book value capital structure rather than its market value capital structure.

Q. Does the forward-looking variance of return on an equity investment depend on the market values or the book values of a company's debt and equity?

A. The forward-looking variance of return on an equity investment depends on the market values of debt and equity—not the book values of debt and equity—because equity investors can only purchase and sell equity at market values. Thus, from the equity investor's point of view, financial risk depends on a company's market value capital structure, not its book value capital structure.

Q. Does the difference between market and book value capital structures help to explain your financial risk adjustment?

A. Yes. As I discuss in my direct testimony, my financial risk adjustment is required because equity investors look at a company's market value capital structure to determine the financial risk of investing in the company's equity, whereas the rates in this proceeding are based on the company's book value capital structure. Because equity investors' views of financial risk as measured in the marketplace are reflected in my cost of equity estimate, but my cost of equity estimate is applied to a book value capital structure through the regulatory process, the equity investor is unlikely to have an opportunity to earn the required marketplace return without my financial risk adjustment.

III. REBUTTAL OF MR. GORMAN

Q. What is Mr. Gorman's recommended cost of equity for Gulf?

A. Mr. Gorman recommends a cost of equity for Gulf equal to 9.45 percent.

Q. How does Mr. Gorman estimate Gulf's cost of equity?

A. Mr. Gorman estimates Gulf's cost of equity by applying several cost of equity methods to essentially the same comparable group of electric utilities that I use in my direct testimony. His cost of equity methods include: (1) the DCF model; (2) a risk premium method; and (3) a Capital Asset Pricing Model ("CAPM").

Q. What areas of Mr. Gorman's testimony will you address in your rebuttal testimony?

A. I will address Mr. Gorman's DCF analysis, risk premium analysis, CAPM analysis, and his comments on my direct testimony.

A. Mr. Gorman's DCF Model

Q. What DCF model does Mr. Gorman use to estimate Gulf's cost of equity?

A. Mr. Gorman uses an annual DCF model to estimate Gulf's cost of equity.

Q. Do you agree with Mr. Gorman's use of an annual DCF model to estimate Gulf's cost of equity?

A. No. As discussed in my rebuttal of Dr. Woolridge, the DCF model is based on the assumption that a company's stock price reflects the present value of the dividends investors expect to receive from their ownership of the stock. Since the companies in Mr. Gorman's analysis all pay dividends quarterly, these companies' stock prices reflect the present value of a quarterly stream of dividends. Hence, the quarterly DCF model is the only DCF model that is consistent with the basic assumption that stock prices are equal to the expected present value of future dividends.

Q. Does Mr. Gorman include an allowance for flotation costs in his DCF analysis?

A. No.

Q. Do you agree with Mr. Gorman's failure to include flotation costs in his DCF analysis?

A. No. As discussed in my direct testimony, flotation costs are a cost of issuing securities that must be reflected in a cost of equity analysis for investors to earn a return that is commensurate with returns on other investments of the same risk.

Q. How does Mr. Gorman estimate the growth component of his DCF model?

A. Mr. Gorman estimates the growth component of his DCF model by using analyst growth forecasts, a "sustainable" growth forecast, and a three-stage growth forecast.

Q. What DCF result does Mr. Gorman obtain when he uses analysts' growth forecasts in his DCF model?

A. Mr. Gorman obtains a DCF result equal to 9.1 percent.

Q. Do you agree with Mr. Gorman's use of analysts' growth forecasts as a proxy for investors' growth expectations in the DCF model?

A. Yes. Mr. Gorman's use of analysts' growth forecasts is consistent with the results of studies, including my own, that demonstrate that analysts' growth forecasts are more highly correlated with stock prices than are other growth forecasts such as historical growth forecasts and sustainable growth forecasts.

Q. Does Mr. Gorman offer any comments on the use of analysts' growth forecasts as a proxy for investors' growth expectations in the DCF model?

A. Yes. Mr. Gorman claims that analysts' growth forecasts overstate investors' long-run growth expectations because they exceed economists' projections of the long-run growth in the economy:

> both practitioners and academics support the notion that long-term sustainable growth cannot be greater than the economy in which the company sells its goods and services. Growth

can exceed the service area economic growth over short periods of time, but over the long-term the expectation that growth will exceed the economy in which it sells its services is not rational. (Gorman at 55)

Q. Mr. Gorman seems to believe that investors' growth expectations must be "rational." Are investors' growth expectations always "rational"?

A. No. In hindsight, most economists would agree that investors' growth expectations during the tech stock boom of the late 1990s and early 2000s and the housing boom of the mid-2000s were irrational. Yet, it was these "irrational" growth expectations that caused stock and housing prices to rise by so much during those times.

Q. Does the DCF Model only require the use of investors' growth expectations when investors' growth expectations are "rational"?

A. No. The DCF model requires the use of investors' growth expectations, whether rational or irrational.

Q. Is it appropriate for Mr. Gorman to adjust the growth term in his DCF model, without also adjusting the stock price term in his model?

A. No. If Mr. Gorman believes that investors' growth expectations are irrational, he should recognize that "irrational" growth expectations are likely to be accompanied by "irrational" stock prices. To be consistent in applying his own definition of "rational," Mr. Gorman would need to adjust not only his growth estimates to reflect the long-run growth in the economy, but also his stock prices to reflect a “rational” estimate of the value of the company.

Q. Do you agree with Mr. Gorman’s use of the “sustainable growth” method of estimating investors’ growth expectations?

A. No. I have two objections to Mr. Gorman’s use of the “sustainable growth” method of estimating investors’ growth expectations. First, the DCF model requires the growth forecasts of investors, and my studies, along with those of others, provide strong evidence that analysts’ growth forecasts are a better proxy for investors’ growth expectations than the sustainable growth rate used by Mr. Gorman. Second, as discussed in my rebuttal of Dr. Woolridge above, the sustainable growth method is logically circular in that each company’s rate of return on equity must be known in order to estimate the sustainable growth rate at the same time that the sustainable growth rate must be known to estimate the rate of return on equity through the DCF model. It is not possible for the rate of return on equity to be known before the sustainable growth rate, and, at the same time, the sustainable growth rate to be known before the rate of return on equity.

Q. What is the basic assumption of Mr. Gorman’s three-stage DCF model?

A. Mr. Gorman’s three-stage DCF model is based on the assumption that investors believe his proxy companies will grow at the average analyst growth rates for five years, decline to the long-run growth in the economy in years six through ten, and beginning in the eleventh year grow at the rate of 4.9 percent forever.

Q. Does Mr. Gorman provide any evidence to support this basic assumption?
A. No. He simply assumes that rational investors would make this assumption.

Q. Why does Mr. Gorman prefer the results of his three-stage DCF model over the results of his constant growth DCF Model?
A. As discussed above, Mr. Gorman prefers the results of his three-stage model because, in his opinion, analysts' growth rates generally exceed the projected growth of the economy, and a company cannot grow forever at a rate in excess of the expected growth of the economy.

Q. Do you agree with Mr. Gorman's opinion that companies cannot grow forever at a rate in excess of the expected growth in the U.S. economy?
A. Yes. As Mr. Gorman implies, if a company grew forever at a rate in excess of the rate of growth of the U.S. economy, it would eventually take over the economy. This is not a reasonable expectation.

Q. Does the opinion that a company cannot grow at a rate greater than the rate of growth in the GNP forever imply that a single-stage DCF model cannot be used to estimate the cost of equity?
A. No. Mr. Gorman fails to recognize that the DCF model requires the growth expectations of investors, not the growth expectations of Mr. Gorman. If investors use analysts' growth rates to value stocks in the marketplace, Mr. Gorman should use analysts' growth rates to estimate the growth component of the DCF model. Mr. Gorman also fails to recognize that companies do not have to grow at the same rate forever for the single-stage

DCF Model to be a reasonable approximation of how prices are determined in capital markets.

Q. Have you done any studies on the growth rates that investors use to value stocks in the marketplace?

A. Yes. As discussed in my direct testimony, my studies indicate that investors use analysts' forecasted growth rates to value stocks in the marketplace (Vander Weide direct at 27 – 29).

Q. Does the opinion that a company cannot grow at a rate of growth greater than the growth in GNP forever imply that Mr. Gorman's assumption that companies can only grow at rates faster than the economy for five years is correct?

A. No. The opinion that a company's earnings cannot grow at a rate greater than the rate of growth in the GNP forever does not imply that companies can only grow faster than the rate of growth in the economy for five years. Mr. Gorman's assumption that companies must grow at the same rate as the economy after year five is completely arbitrary.

B. Mr. Gorman's Risk Premium Model

Q. How does Mr. Gorman estimate the required risk premium for investing in his electric company proxy group?

A. Mr. Gorman estimates the required risk premium for investing in his proxy electric utilities by comparing the average authorized electric utility rate of return on equity for each year from 1986 through June 2013 to both the average interest rate on long-term Treasury bonds and the average interest rate on A-rated utility bonds in each year. Mr. Gorman finds that the authorized rate of return on equity for electric utilities generally exceeds the interest rate on long-term Treasury bonds by 441 to 631 basis points, and exceeds the interest rate on A-rated utility bonds by 303 to 489 basis points. Giving seventy-five percent weight to the upper end of his risk premium ranges and twenty-five percent weight to the lower end of his risk premium ranges, Mr. Gorman concludes that the required risk premium on long-term Treasury bonds is 5.84 percent and the required risk premium on A-rated utility bonds is 4.43 percent.

Q. How does Mr. Gorman use this information on required risk premiums to estimate Gulf's cost of equity?

A. Mr. Gorman adds his 5.84 percent risk premium over long-term Treasury bonds to his forecasted Treasury bond yield of 4.2 percent to obtain a 10.04 percent risk premium estimate of the cost of equity. Mr. Gorman also adds his 4.43 percent risk premium over A-rated utility bonds to the current 5.23 percent yield on Baa-rated utility bonds to obtain a 9.66 percent estimate of the risk premium cost of equity. The average of these two estimates is 9.85 percent.

Q. Do you agree with Mr. Gorman's method of estimating the required risk premium on electric utility stocks?

A. No. Mr. Gorman fails to recognize that the indicated risk premium in his data base tends to increase as interest rates decline. Mr. Gorman should have adjusted his average risk premiums to account for the relationship between the allowed risk premium on equity and the level of interest rates on long-term Treasury bonds and utility bonds.

Q. Have you studied the relationship between the allowed rates of return on equity by regulatory commissions and the interest rates on long-term Treasury bonds reported by Mr. Gorman?

A. Yes. Using the data found in Mr. Gorman's Exhibit MPG-11, I perform a regression analysis of the relationship between the risk premium implied by the allowed rates of return on equity issued by regulatory commissions and the interest rates on long-term Treasury bonds. I find that the risk premium implied by allowed rates of return compared to the yield on long-term Treasury bonds is given by the relationship:

$RP_{AUTHORIZED}$	=	8.03 –	$0.448 \times T_B$
t-statistic	=	(27.17)	(9.43)

where:

$RP_{AUTHORIZED}$	=	the risk premium implied by utility commission authorized rates of return on equity,
8.03 and 0.448	=	estimated regression coefficients with t-statistics shown in parentheses; and
T_B	=	the yield on long-term Treasury bonds.

Q. What is the meaning of the negative 0.448 coefficient on the Treasury bond variable?

A. The negative 0.448 coefficient on the Treasury bond variable indicates that the authorized risk premium increases by approximately forty-five basis points for every one hundred basis point decrease in interest rates.

Q. What is the meaning of the 9.43 t-statistic in the above equation?

A. The 9.43 t-statistic indicates that there is less than one chance in one hundred that the negative relationship between the risk premium and interest rates is due to "chance," that is, the negative coefficient is statistically significant.

Q. Have you also studied the relationship between the allowed rates of return on equity by regulatory commissions and the interest rates on utility bonds reported by Mr. Gorman?

A. Yes. Using the data found in Mr. Gorman's Exhibit MPG-12, I find that the risk premium implied by allowed rates of return compared to the yield on utility bonds is given by the relationship:

$RP_{AUTHORIZED}$	=	7.24 –	$0.446 \times A_B$
t-statistic	=	(21.64)	(10.10)

where:

$RP_{AUTHORIZED}$ = the risk premium implied by utility commission authorized rates of return on equity,

7.24 and 0.446	=	estimated regression coefficients with t-statistics shown in parentheses; and
A_B	=	the yield on Moody's A-rated utility bonds.

Q. Do these regression equations support the conclusion that the risk premium tends to increase when interest rates decline?

A. Yes. The negative coefficients associated with the interest rate variables, T_B and A_B, indicate that the risk premium moves in the opposite direction as interest rates, thus verifying the conclusion that the risk premium increases when interest rates decline.

Q. What risk premium do you obtain from your statistical analysis of the relationship between allowed rates of return and the interest rate on long-term Treasury bonds?

A. Using Mr. Gorman's forecasted 4.2 percent interest rate on long-term Treasury bonds, I obtain a risk premium of 6.15 percent over the forecasted yield to maturity on long-term Treasury bonds. This risk premium estimate is eighty basis points higher than the average 5.35 percent average risk premium on U.S. Treasury bonds shown on Mr. Gorman's Exhibit MPG-11, page 1 of 1.

Q. What risk premium do you obtain from your statistical analysis of the relationship between allowed rates of return and the interest rate on utility bonds?

A. Using Mr. Gorman's 5.23 percent current interest rate on utility bonds, I obtain a risk premium of 4.91 percent. This risk premium estimate is approximately one hundred basis points higher than the average 3.95 percent risk premium shown on Mr. Gorman's Exhibit MPG-12, page 1 of 1.

Q. Why are the estimated risk premiums from your regression analyses higher than the average risk premiums over the period 1986 – June 2013?

A. The risk premiums from my regression analyses are higher than the average risk premiums over the period of Mr. Gorman's studies because, as discussed above, risk premiums generally increase when interest rates decline, and interest rates have declined over the period of Mr. Gorman's studies. My regression analyses correctly take into account the inverse relationship between risk premiums and interest rates.

Q. What cost of equity estimates would Mr. Gorman have obtained from his risk premium analyses if he had correctly recognized that risk premiums increase when interest rates decline, as you describe above?

A. Using Mr. Gorman's forecasted 4.2 percent yield on long-term Treasury bonds and a current yield of 5.23 percent on utility bonds, Mr. Gorman would have obtained estimated risk premiums of 6.15 percent over long-term Treasury bonds and 4.91 percent over utility bonds. Adding these risk premium estimates to the forecasted interest rates, Mr. Gorman would have obtained cost of equity estimates of 10.35 percent and 10.14 percent, respectively. These results exceed Mr. Gorman's risk premium estimates of the cost of equity by approximately thirty to fifty basis points and exceed his recommended cost of equity by seventy to ninety basis points.

C. Mr. Gorman's CAPM

Q. The CAPM requires estimates of the risk-free rate, the company-specific risk factor, or beta, and either the required return on an investment in the market portfolio, or the risk premium on the market portfolio compared to an investment in risk-free government securities. How does Mr. Gorman estimate these CAPM inputs?

A. For the risk-free rate, Mr. Gorman uses a 4.2 percent forecasted yield on long-term Treasury bonds; for the company-specific risk factor or beta, Mr. Gorman uses the average 0.74 Value Line beta for his proxy companies; and for the required return or risk premium on the market portfolio, Mr. Gorman employs Morningstar's market risk premium of 6.7 percent (Gorman at 38 - 42).

Q. What CAPM result does Mr. Gorman obtain from his CAPM analysis?

A. Mr. Gorman obtains a CAPM result of 9.1 percent (Gorman at 43).

Q. Do you agree with the use of a forecasted interest rate to estimate the risk-free rate component of the CAPM?

A. Yes. However, I believe that Mr. Gorman should have looked at additional interest rate forecasts, such as those provided by the Energy Information Administration ("EIA").

Q. Do you have other comments on Mr. Gorman's CAPM analysis?

A. Yes. Mr. Gorman fails to acknowledge the extensive evidence that the CAPM underestimates the cost of equity for companies such as electric utilities with betas less than 1.0. Because of this evidence, I recommend that the Commission give little weight to Mr. Gorman's CAPM analysis.

D. Response to Mr. Gorman's Comments on Dr. Vander Weide's Testimony

Q. Does Mr. Gorman agree with your cost of equity estimate for Gulf?

A. Mr. Gorman disagrees with my: (i) financial risk adjustment [Gorman at 49 – 53]; (ii) DCF analysis [Gorman at 53 – 59]; and (iii) risk premium analysis [Gorman at 60 – 63].

1. Financial Risk Adjustment

Q. Why do you adjust the cost of equity results for your proxy companies to reflect the average difference between the financial risk of your proxy companies and the financial risk reflected in Gulf's recommended capital structure?

A. I adjust my cost of equity results because they reflect a higher degree of financial risk than Gulf's recommended capital structure. In making this assessment, I recognize that investors measure the financial risk of investing in the equity of my proxy companies based on these companies' market value capital structures, while Gulf is recommending a book value capital structure. Since investors demand a higher return for bearing greater risk, an adjustment is required to the cost of equity result for the proxy companies (see Vander Weide Direct at 50 – 52).

Q. Why do equity investors measure the financial risk of your proxy companies based on their market value capital structures?

A. Equity investors measure financial risk based on market value capital structures because, from the equity investor's point of view, risk is measured by the forward-looking variance of return on investment; and the variance of return on investment depends on a company's market value capitalization, not its book value capitalization.

Q. How does Mr. Gorman define financial risk?

A. Mr. Gorman defines financial risk as the ability of a company to meet its financial obligation to pay the interest and principal on its debt (Gorman at 50).

Q. Does Mr. Gorman's definition of financial risk reflect the point of view of equity investors?

A. No. Mr. Gorman's definition of financial risk reflects the point of view of debt investors, not the point of view of equity investors. Whereas debt investors are justifiably concerned with a company's ability to cover the interest and principal payments on its debt, equity investors are primarily concerned with the forward-looking variance of return on their investment. As noted above, the forward-looking variance of return on investment depends on a company's market value capital structure, not its book value capital structure. Indeed, equity investors generally cannot buy a company's stock at book value.

Q. In summary, do you agree with Mr. Gorman's criticism of your financial risk adjustment?

A. No. Mr. Gorman fails to recognize that equity investors measure financial risk by the forward-looking variance of return on their equity investment in the company, and the forward-looking variance of return on an equity investment in a company reflects the company's market value capital structure. Mr. Gorman's criticism of my financial risk adjustment depends on his incorrect assertion that financial risk reflects book value capitalization ratios rather than market value capitalization ratios. While his assertion may be correct from the bond investor's point of view, it is certainly not correct from the equity investor's point of view. The equity investor's point of view is the only point of view that is relevant for determining the cost of equity.

2. DCF Analysis

Q. What issues does Mr. Gorman have with regard to your DCF analysis?

A. Mr. Gorman addresses my: (1) use of a quarterly DCF model; (2) flotation cost adjustment; and (3) reliance on analysts' growth forecasts.

Q. Why does Mr. Gorman disagree with your use of a quarterly DCF model?

A. Mr. Gorman claims that my use of a quarterly DCF model is inappropriate because "the quarterly compounding component of the return is not a cost to the utility" (Gorman at 56).

Q. Does Mr. Gorman attempt to explain his position on the quarterly compounding return through an example?

A. Yes. Mr. Gorman provides an example where he assumes that Gulf has issued a bond with a face value of $1,000, at an interest rate of six percent paid in two semi-annual $30 installments. He asserts that Gulf's cost of this bond is only six percent, whereas the bond investor expects to earn a 6.1 percent return because of the compounding effect of semi-annual coupon payments (Gorman at 57).

Q. Do you agree with Mr. Gorman's assertion that the cost of the bond to Gulf in his example is only six percent?

A. No. The cost of the bond to Gulf is calculated by solving for the value of the discount rate that equates the present value of the stream of interest and principal payments to the face value of the bond. In Mr. Gorman's example, the cost of the bond is 6.09 percent because:

$$\$1,000 = \$30 \div (1.0609)^{.5} + \$1,030 \div (1.0609)$$

Q. Mr. Gorman claims in his example that the cost of a $1,000 bond with a six percent interest rate is the same when a company makes two semi-annual coupon payments as it is when the company makes a single, end-of-year payment of $60. Is Mr. Gorman correct?

A. No. The cost of a $1,000 bond is greater when the company makes two semi-annual coupon payments of thirty dollars than when it makes a single coupon payment of sixty dollars at the end of the year. It can be easily demonstrated that the cost of the $1,000 bond with a single end-of-year interest payment of sixty dollars is six percent, whereas, as shown above, the cost of the $1,000 bond with semi-annual interest payments equal to thirty dollars is 6.09 percent.

Q. Why is the company's cost of debt greater when it makes two semi-annual payments than when it makes a single end-of-year payment?

A. The company's cost of debt is greater when it makes two semi-annual interest payments of thirty dollars than it is when it makes a single sixty dollar payment at the end of the year because the interest payments are made sooner on average when interest is paid semi-annually than when the company makes a single payment at the end of the year. Because of the time value of money, earlier payments are more costly to the issuing company than later payments of an equal dollar amount. In Mr. Gorman's discussion, he simply fails to recognize the time value of money.

Q. Does Mr. Gorman attempt to extend his example to investments in stocks?

A. Yes. Mr. Gorman provides a stock example where an investor purchases Gulf stock for $100 and expects to receive four quarterly dividends equal to $1.50 each, or six percent per year (Gorman at 58). In his discussion of this example, Mr. Gorman asserts that the cost of the company's dividend payment is only six percent, whereas the return to the investor would be 6.13 percent.

Q. Do you agree with Mr. Gorman's assertion that the cost to the company of the quarterly dividend payments in his example is only six percent?

A. No. Assuming for simplicity that the value of the investment is the same at the end of the year as it is at the beginning of the year, the cost of the quarterly dividend payments to the company can be calculated by solving for the value of the discount rate that equates the present value of the stream of quarterly dividend payments and capital value at the end of the year to the $100 price of the stock. In Mr. Gorman's example, the cost to the company of the dividend payments is 6.14 percent because:

$100 = $1.50÷(1.0614)^.25 + 1.50÷(1.0614)^.5 + 1.50÷(1.0614)^.75 + 101.5÷(1.0614)

Q. In his stock example, Mr. Gorman claims that the cost of equity to the company is the same when the company makes four quarterly dividend payments equal to $1.50 each as it is when the company makes a single, year-end dividend payment equal to six dollars. Is he correct?

A. No. The cost of equity is greater when the company makes four quarterly $1.50 dividend payments than when it makes a single six dollar dividend payment at the end of the year because the quarterly payment of dividends requires the company to make dividend payments sooner on average than the annual payment, and sooner payments are always more costly than later payments.

Q. Are Mr. Gorman's concerns with your use of analysts' forecasts and a flotation cost adjustment similar to the concerns expressed by Dr. Woolridge?

A. Yes, they are.

Q. Have you responded to these concerns in your rebuttal of Dr. Woolridge?
A. Yes, I have.

3. Risk Premium Analysis

Q. What issue does Mr. Gorman have with regard to your risk premium analysis?
A. Mr. Gorman objects to my use of a forecasted, rather than a current interest rate, in my risk premium analysis (Gorman at 61).

Q. Why do you use a forecasted, rather than a current interest rate, in your risk premium analysis?
A. I use a forecasted interest rate because the fair rate of return standard requires that Gulf have an opportunity to earn its cost of equity during the period when rates are in effect, and the rates approved in this case will not come into effect until a time in 2014.

Q. Does Mr. Gorman also use forecasted interest rates in estimating Gulf's cost of equity in his risk premium approach?
A. Yes. Mr. Gorman uses forecasted, rather than current interest rates in his risk premium analysis comparing the average allowed return on equity for electric utilities to interest rates on thirty-year Treasury bonds (Gorman at 35).

Q. Does Mr. Gorman attempt to estimate the cost of equity you would have obtained from your ex ante risk premium analysis if you had used current bond yields rather than forecasted bond yields?

A. Yes. Mr. Gorman claims that my ex ante risk premium analysis would have produced a cost of equity equal to 9.4 percent if I were to use an interest rate on A-rated utility bonds equal to 4.73 percent (Gorman at 62).

Q. Do you agree with Mr. Gorman's claim that your ex ante risk premium analysis would produce a cost of equity result equal to 9.4 percent if you were to use an A-rated utility bond yield equal to 4.73 percent?

A. No. Mr. Gorman obtains his 9.4 percent result by adding my estimated 4.9 percent equity risk premium reported in my direct testimony to the 4.73 percent current yield on A-rated utility bonds. However, Mr. Gorman fails to recognize that my estimated ex ante risk premium depends on the value of the interest rate on A-rated utility bonds through the estimated regression equation described in Appendix 4 of Exhibit ___ (JVW-2) to my direct testimony. Although 4.62 percent is the correct ex ante risk premium estimate given an interest rate of 6.55 percent, the correct ex ante risk premium estimate when the interest rate is 4.73 percent is 5.61 percent ($5.61 = 8.18 - 0.543 \times 4.73$). Thus, adding the correct 5.61 percent estimated ex ante risk premium to the interest rate of 4.73 percent produces an ex-ante risk premium cost of equity equal to 10.3 percent, not the 9.4 percent incorrectly calculated by Mr. Gorman.

IV. UPDATED COST OF EQUITY

Q. Mr. Gorman states that the data through February 2013 used in your DCF study is stale and does not reflect current market costs (Gorman at 54). Have you examined your cost of equity recommendation in light of more recent capital market information?

A. Yes. I have examined my DCF, ex ante risk premium, ex post risk premium, and CAPM studies using data through September 2013.

Q. What results do you obtain using data through September 2013?

A. Using data through September 2013 and the methods described in my direct testimony, the DCF cost of equity estimate for the electric proxy group is 9.8 percent; the current ex post risk premium cost of equity estimate is 10.9 percent; the ex-ante risk premium cost of equity estimate is 11.2 percent; and the CAPM cost of equity estimates are equal to 10.3 percent and 10.7 percent. A summary of these results is shown below in Table 3 and Schedules 2, 3, 4, 5, and 6 of Exhibit ___ (JVW-3).

Table 2

Cost of Equity Model Results Using Data through September 2013

Model	Model Result
Discounted Cash Flow	9.8%
Ex Ante Risk Premium	11.2%
Ex Post Risk Premium	10.9%
CAPM - Historical	10.3%
CAPM - DCF Based	10.7%
Average	10.6%
Average without CAPM	10.6%

Q. Do your analyses using data through September 2013 support your cost of equity recommendation for Gulf presented in your direct testimony?

A. Yes. My original 10.8 percent cost of equity estimate falls within the range of results I obtain using recent data, and thus my recent studies continue to support my recommended 11.5 percent return, which includes my financial risk adjustment.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Exhibit

TABLE 1. RESEARCH LITERATURE THAT STUDIES THE EFFICACY OF ANALYSTS' EARNINGS FORECASTS

Abarbanell, J., and Reuven Lehavy (2003). "Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/underreaction in analysts' earnings forecasts." Journal of Accounting & Economics **36**: 105-146.

Brown, L. D. (1997). "Analyst forecasting errors: additional evidence." Financial Analysts Journal November/December: 81-88.

Ciccone, S. J. (2005). "Trends in analyst earnings forecast properties." International Review of Financial Analysis **14**: 1-22.

Clarke, J., Stephen P. Ferris, Narayanan Jayaraman, and Jinsoo Lee (2006). "Are analyst recommendations biased? Evidence from corporate bankruptcies." Journal of Financial and Quantitative Analysis **41**(1): 169-196.

Crichfield, T., Thomas Dyckman and Josef Lakonishok (1978). "An evaluation of security analysts' forecasts." The Accounting Review **53**(3): 651-668.

Elton, E. J., Martin J. Gruber and Mustafa N. Gultekin (1984). "Professional expectations: accuracy and diagnosis of errors." Journal of Financial and Quantitative Analysis **19**(4): 351-363.

Givoly, D., and Josef Lakonishok (1984). "Properties of analysts' forecasts of earnings: a review and analysis of the research." Journal of Accounting Literature **3**: 119-148.

Keane, M. P., and David E. Runkle (1998). "Are financial analysts' forecasts of corporate profits rational." The Journal of Political Economy **106**(4): 768-805.

Yang, R., and Yaw M. Mensah (2006). "The effect of the SEC's regulation fair disclosure on analyst forecast attributes." Journal of Financial Regulation and Compliance **14**(2): 192-209.

SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR ELECTRIC UTILITIES

LINE	COMPANY	D_0	P_0	GROWTH	MODEL RESULT
1	ALLETE	0.475	49.798	6.00%	10.4%
2	Alliant Energy	0.470	50.925	4.80%	9.0%
3	Amer. Elec. Power	0.490	44.533	4.00%	8.9%
4	Avista Corp.	0.305	27.319	5.00%	10.1%
5	CenterPoint Energy	0.207	23.928	4.50%	8.4%
6	CMS Energy Corp.	0.255	27.155	5.87%	10.1%
7	Dominion Resources	0.563	58.997	7.03%	11.4%
8	DTE Energy	0.655	68.018	4.60%	8.9%
9	Duke Energy	0.780	68.092	3.66%	8.7%
10	FirstEnergy Corp.	0.550	37.590	1.74%	8.2%
11	G't Plains Energy	0.217	22.929	6.43%	10.8%
12	Integrys Energy	0.680	58.342	5.00%	10.3%
13	NextEra Energy	0.660	82.920	6.54%	10.2%
14	Northeast Utilities	0.367	42.273	7.62%	11.7%
15	Pepco Holdings	0.270	19.454	3.82%	10.1%
16	Pinnacle West Capital	0.545	56.057	4.73%	9.2%
17	PNM Resources	0.165	22.665	6.43%	9.6%
18	Portland General	0.275	30.098	6.45%	10.7%
19	SCANA Corp.	0.507	49.316	4.75%	9.4%
20	Southern Co.	0.507	43.010	4.28%	9.6%
21	TECO Energy	0.220	17.010	2.82%	8.6%
22	UIL Holdings	0.432	38.637	7.41%	12.7%
23	Wisconsin Energy	0.383	41.486	5.21%	9.0%
24	Xcel Energy Inc.	0.280	28.502	4.91%	9.3%
25	Average				9.8%

Notes:

d_0	=	Most recent quarterly dividend.
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends by the factor (1 + g).
P_0	=	Average of the monthly high and low stock prices during the three months ending September 2013 per Thomson Reuters.
FC	=	Flotation cost allowance (five percent) as a percent of stock price.
g	=	I/B/E/S forecast of future earnings growth September 2013 from Thomson Reuters.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC UTILITIES TO THE INTEREST RATE ON MOODY'S A-RATED UTILITY BONDS

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Sep-99	0.1157	0.0793	0.0364
2	Oct-99	0.1161	0.0806	0.0355
3	Nov-99	0.1192	0.0794	0.0398
4	Dec-99	0.1236	0.0814	0.0422
5	Jan-00	0.1221	0.0835	0.0386
6	Feb-00	0.1269	0.0825	0.0444
7	Mar-00	0.1313	0.0828	0.0485
8	Apr-00	0.1237	0.0829	0.0408
9	May-00	0.1227	0.0870	0.0357
10	Jun-00	0.1242	0.0836	0.0406
11	Jul-00	0.1247	0.0825	0.0422
12	Aug-00	0.1228	0.0813	0.0415
13	Sep-00	0.1164	0.0823	0.0341
14	Oct-00	0.1170	0.0814	0.0356
15	Nov-00	0.1191	0.0811	0.0380
16	Dec-00	0.1166	0.0784	0.0382
17	Jan-01	0.1194	0.0780	0.0414
18	Feb-01	0.1203	0.0774	0.0429
19	Mar-01	0.1207	0.0768	0.0439
20	Apr-01	0.1233	0.0794	0.0439
21	May-01	0.1279	0.0799	0.0480
22	Jun-01	0.1285	0.0785	0.0500
23	Jul-01	0.1295	0.0778	0.0517
24	Aug-01	0.1302	0.0759	0.0543
25	Sep-01	0.1321	0.0775	0.0546
26	Oct-01	0.1313	0.0763	0.0550
27	Nov-01	0.1296	0.0757	0.0539
28	Dec-01	0.1292	0.0783	0.0509
29	Jan-02	0.1274	0.0766	0.0508
30	Feb-02	0.1285	0.0754	0.0531
31	Mar-02	0.1248	0.0776	0.0472
32	Apr-02	0.1227	0.0757	0.0470
33	May-02	0.1236	0.0752	0.0484
34	Jun-02	0.1254	0.0741	0.0513

35	Jul-02	0.1337	0.0731	0.0606
36	Aug-02	0.1300	0.0717	0.0583
37	Sep-02	0.1272	0.0708	0.0564
38	Oct-02	0.1291	0.0723	0.0568
39	Nov-02	0.1242	0.0714	0.0528
40	Dec-02	0.1226	0.0707	0.0519
41	Jan-03	0.1195	0.0706	0.0489
42	Feb-03	0.1233	0.0693	0.0540
43	Mar-03	0.1212	0.0679	0.0533
44	Apr-03	0.1170	0.0664	0.0506
45	May-03	0.1095	0.0636	0.0459
46	Jun-03	0.1047	0.0621	0.0426
47	Jul-03	0.1072	0.0657	0.0415
48	Aug-03	0.1064	0.0678	0.0386
49	Sep-03	0.1029	0.0656	0.0373
50	Oct-03	0.1009	0.0643	0.0366
51	Nov-03	0.0985	0.0637	0.0348
52	Dec-03	0.0946	0.0627	0.0319
53	Jan-04	0.0921	0.0615	0.0306
54	Feb-04	0.0916	0.0615	0.0301
55	Mar-04	0.0912	0.0597	0.0315
56	Apr-04	0.0925	0.0635	0.0290
57	May-04	0.0962	0.0662	0.0300
58	Jun-04	0.0961	0.0646	0.0315
59	Jul-04	0.0953	0.0627	0.0326
60	Aug-04	0.0966	0.0614	0.0352
61	Sep-04	0.0951	0.0598	0.0353
62	Oct-04	0.0953	0.0594	0.0359
63	Nov-04	0.0918	0.0597	0.0321
64	Dec-04	0.0920	0.0592	0.0328
65	Jan-05	0.0925	0.0578	0.0347
66	Feb-05	0.0917	0.0561	0.0356
67	Mar-05	0.0918	0.0583	0.0335
68	Apr-05	0.0924	0.0564	0.0360
69	May-05	0.0910	0.0553	0.0356
70	Jun-05	0.0911	0.0540	0.0371
71	Jul-05	0.0899	0.0551	0.0348
72	Aug-05	0.0900	0.0550	0.0350
73	Sep-05	0.0923	0.0552	0.0371

74	Oct-05	0.0934	0.0579	0.0355
75	Nov-05	0.0981	0.0588	0.0393
76	Dec-05	0.0980	0.0580	0.0400
77	Jan-06	0.0980	0.0575	0.0405
78	Feb-06	0.1071	0.0582	0.0489
79	Mar-06	0.1055	0.0598	0.0457
80	Apr-06	0.1075	0.0629	0.0446
81	May-06	0.1087	0.0642	0.0445
82	Jun-06	0.1117	0.0640	0.0477
83	Jul-06	0.1110	0.0637	0.0473
84	Aug-06	0.1072	0.0620	0.0452
85	Sep-06	0.1111	0.0600	0.0511
86	Oct-06	0.1074	0.0598	0.0476
87	Nov-06	0.1078	0.0580	0.0498
88	Dec-06	0.1071	0.0581	0.0490
89	Jan-07	0.1096	0.0596	0.0500
90	Feb-07	0.1085	0.0590	0.0495
91	Mar-07	0.1094	0.0585	0.0509
92	Apr-07	0.1042	0.0597	0.0445
93	May-07	0.1068	0.0599	0.0469
94	Jun-07	0.1123	0.0630	0.0493
95	Jul-07	0.1130	0.0625	0.0505
96	Aug-07	0.1104	0.0624	0.0480
97	Sep-07	0.1078	0.0618	0.0460
98	Oct-07	0.1084	0.0611	0.0473
99	Nov-07	0.1116	0.0597	0.0519
100	Dec-07	0.1132	0.0616	0.0516
101	Jan-08	0.1193	0.0602	0.0591
102	Feb-08	0.1133	0.0621	0.0512
103	Mar-08	0.1170	0.0621	0.0549
104	Apr-08	0.1159	0.0629	0.0530
105	May-08	0.1162	0.0627	0.0535
106	Jun-08	0.1136	0.0638	0.0499
107	Jul-08	0.1172	0.0640	0.0532
108	Aug-08	0.1191	0.0637	0.0554
109	Sep-08	0.1185	0.0649	0.0536
110	Oct-08	0.1280	0.0756	0.0524
111	Nov-08	0.1312	0.0760	0.0552
112	Dec-08	0.1301	0.0654	0.0647

113	Jan-09	0.1241	0.0639	0.0602
114	Feb-09	0.1269	0.0630	0.0639
115	Mar-09	0.1286	0.0642	0.0644
116	Apr-09	0.1266	0.0648	0.0617
117	May-09	0.1242	0.0649	0.0593
118	Jun-09	0.1220	0.0620	0.0600
119	Jul-09	0.1174	0.0597	0.0577
120	Aug-09	0.1158	0.0571	0.0587
121	Sep-09	0.1152	0.0553	0.0599
122	Oct-09	0.1153	0.0555	0.0598
123	Nov-09	0.1196	0.0564	0.0633
124	Dec-09	0.1095	0.0579	0.0516
125	Jan-10	0.1112	0.0577	0.0535
126	Feb-10	0.1091	0.0587	0.0504
127	Mar-10	0.1076	0.0584	0.0492
128	Apr-10	0.1111	0.0582	0.0529
129	May-10	0.1093	0.0552	0.0541
130	Jun-10	0.1088	0.0546	0.0541
131	Jul-10	0.1078	0.0526	0.0552
132	Aug-10	0.1057	0.0501	0.0557
133	Sep-10	0.1059	0.0501	0.0558
134	Oct-10	0.1044	0.0510	0.0534
135	Nov-10	0.1051	0.0536	0.0514
136	Dec-10	0.1053	0.0557	0.0497
137	Jan-11	0.1044	0.0557	0.0487
138	Feb-11	0.1041	0.0568	0.0473
139	Mar-11	0.1044	0.0556	0.0488
140	Apr-11	0.1020	0.0555	0.0465
141	May-11	0.0994	0.0532	0.0462
142	Jun-11	0.1043	0.0526	0.0517
143	Jul-11	0.1019	0.0527	0.0492
144	Aug-11	0.1050	0.0469	0.0581
145	Sep-11	0.1016	0.0448	0.0568
146	Oct-11	0.1032	0.0452	0.0580
147	Nov-11	0.1014	0.0425	0.0589
148	Dec-11	0.1024	0.0435	0.0589
149	Jan-12	0.1016	0.0434	0.0582
150	Feb-12	0.0974	0.0436	0.0538
151	Mar-12	0.0971	0.0448	0.0523

152	Apr-12	0.0994	0.0440	0.0554
153	May-12	0.0981	0.0420	0.0561
154	Jun-12	0.0962	0.0408	0.0554
155	Jul-12	0.0963	0.0393	0.0570
156	Aug-12	0.0972	0.0400	0.0572
157	Sep-12	0.0968	0.0402	0.0566
158	Oct-12	0.0978	0.0391	0.0587
159	Nov-12	0.0935	0.0384	0.0551
160	Dec-12	0.0962	0.0400	0.0562
161	Jan-13	0.0968	0.0415	0.0553
162	Feb-13	0.0956	0.0418	0.0538
163	Mar-13	0.0976	0.0420	0.0556
164	Apr-13	0.0966	0.0400	0.0566
165	May-13	0.0970	0.0417	0.0553
166	Jun-13	0.0990	0.0453	0.0537
167	Jul-13	0.0978	0.0468	0.0510
168	Aug-13	0.0958	0.0473	0.0485
169	Sep-13	0.0950	0.0480	0.0470

Notes: Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 4 in my direct testimony for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

d_0	=	Latest quarterly dividend per Value Line, Thomson Reuters
P_0	=	Average of the monthly high and low stock prices for each month per Thomson Reuters
g	=	I/B/E/S forecast of future earnings growth for each month.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0(1-FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

	EX ANTE RISK PREMIUM COST OF EQUITY	
1	intercept coefficient/(1-serial correlation coefficient =	0.0812
2	Bond coefficient	(0.5432)
3	Bond yield =	0.0664
4	Bond coefficient x Bond yield =	(0.0361)
5	Ex Ante Risk Premium	0.0451
6	Bond yield =	0.0664
7	Ex Ante Risk Premium Cost of Equity =	11.2%

Forecast bond yield calculated from Value Line and EIA forecast data. Value Line Selection & Opinion (August 23, 2013) projects an AAA-rated Corporate bond yield equal to 6.0 percent. The August 2013 average spread between A-rated utility bonds and Aaa-rated Corporate bonds is nineteen basis points (A-rated utility, 4.73 percent, less Aaa-rated Corporate, 4.54 percent, equals nineteen basis points). Adding nineteen basis points to the 6.0 percent Value Line AAA Corporate bond forecast equals a forecast yield of 6.19 percent for the A-rated utility bonds. The EIA at April 2013 forecasts an AA-rated utility bond yield equal to 6.88 percent. The average spread between AA-rated utility and A-rated utility bonds at August 2013 is twenty basis points (4.73 percent less 4.53 percent). Adding twenty basis points to EIA's 6.88 percent AA-utility bond yield forecast equals a forecast yield for A-rated utility bonds equal to 7.08 percent. The average of the forecasts (6.19 percent using Value Line data and 7.08 percent using EIA data) is 6.64 percent.

EX POST RISK PREMIUM COST OF EQUITY

LINE		
1	Risk Premium S&P 500	4.4%
2	Risk Premium S&P Utilities	3.7%
3	Average Risk Premium	4.1%
4	Forecast Yield A-utility bond	6.6%
5	Flotation	0.23%
6	Risk Premium Cost of Equity	10.9%

See Vander Weide Direct testimony, Exhibit ___(JVW-1) Schedule 3 and Exhibit ___(JVW-1) Schedule 4 for ex post risk premium data.

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: James H. Vander Weide, Ph.D.
Exhibit No. ____ (JVW-3)
Schedule 5

CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY USING THE IBBOTSON® SBBI® 6.7 PERCENT RISK PREMIUM

LINE		VALUE	DESCRIPTION
1	Risk-free Rate	5.17%	Long-term Treasury bond yield forecast
2	Beta	0.73	Average Beta Electric Utilities
3	Risk Premium	6.7%	Long-horizon SBBI risk premium
4	Beta x Risk Premium	4.9%	
5	Flotation	0.23%	
6	Model Result	10.3%	

Ibbotson SBBI risk premium from 2013 Ibbotson® SBBI® Stocks, Bonds, Bills, and Inflation® Valuation Yearbook; Value Line beta for comparable companies. Value Line beta for comparable utilities from Value Line Investment Analyzer. Forecast 20-year Treasury bond yield from Value Line Selection & Opinion, August 2013 and EIA 2013. Value Line forecasts a yield on 10-year Treasury notes equal to 4.0 percent. The current spread between the average August 2013 yield on 10-year Treasury notes (2.74 percent) and 20-year Treasury bonds (3.49 percent) is seventy-five basis points. Adding seventy-five basis points to Value Line's 4.0 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 4.75 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, August 23, 2013). EIA forecasts a yield of 4.84 percent on 10-year Treasury notes. Adding the seventy-five basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.84 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 5.59 percent. The average of the forecasts is 5.17 percent (4.75 percent using Value Line data and 5.59 percent using EIA data).

VALUE LINE BETAS FOR COMPARABLE UTILITIES

LINE	COMPANY	VALUE LINE BETA
1	ALLETE	0.70
2	Alliant Energy	0.75
3	Amer. Elec. Power	0.70
4	Avista Corp.	0.70
5	CenterPoint Energy	0.80
6	CMS Energy Corp.	0.75
7	Dominion Resources	0.70
8	DTE Energy	0.75
9	Duke Energy	0.60
10	FirstEnergy Corp.	0.80
11	G't Plains Energy	0.80
12	Integrys Energy	0.90
13	NextEra Energy	0.70
14	Northeast Utilities	0.75
15	Pepco Holdings	0.75
16	Pinnacle West Capital	0.70
17	PNM Resources	0.90
18	Portland General	0.75
19	SCANA Corp.	0.65
20	Southern Co.	0.55
21	TECO Energy	0.85
22	UIL Holdings	0.75
23	Wisconsin Energy	0.65
24	Xcel Energy Inc.	0.65
25	Average	0.73

CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY USING DCF ESTIMATE OF THE EXPECTED RATE OF RETURN ON THE MARKET PORTFOLIO

LINE		VALUE	DESCRIPTION
1	Risk-free Rate	5.17%	Long-term Treasury bond yield forecast
2	Beta	0.73	Average Beta Electric Utilities
3	DCF S&P 500	12.4%	DCF Cost of Equity S&P 500 (see following)
4	Risk Premium	7.3%	
5	Beta x Risk Premium	5.3%	
6	Flotation cost	0.23%	
7	Model Result	10.7%	

CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY USING DCF ESTIMATE OF THE EXPECTED RATE OF RETURN ON THE MARKET PORTFOLIO (continued)

LINE	COMPANY	P_0	D_0	GROWTH	MODEL RESULT
1	3M	113.14	2.54	10.67%	13.2%
2	ABBOTT LABORATORIES	35.59	0.56	11.87%	13.6%
3	ACCENTURE CLASS A	74.30	1.62	10.12%	12.5%
4	AETNA	62.65	0.80	11.57%	13.0%
5	AIR PRDS.& CHEMS.	99.88	2.84	9.15%	12.3%
6	AIRGAS	100.38	1.92	12.57%	14.7%
7	ALLERGAN	90.04	0.20	12.86%	13.1%
8	ALLSTATE	49.10	1.00	9.06%	11.3%
9	ALTERA	34.23	0.60	12.00%	14.0%
10	AMERICAN EXPRESS	75.19	0.92	11.80%	13.2%
11	AMERICAN INTL.GP.	45.88	0.40	11.32%	12.3%
12	AMGEN	103.73	1.88	8.96%	10.9%
13	ANALOG DEVICES	46.83	1.36	11.00%	14.3%
14	AON CLASS A	66.02	0.70	10.20%	11.4%
15	ASSURANT	52.34	1.00	9.67%	11.8%
16	AT&T	35.13	1.80	6.46%	12.0%
17	AUTOMATIC DATA PROC.	70.45	1.74	9.67%	12.4%
18	BALL	43.89	0.52	9.50%	10.8%
19	BAXTER INTL.	71.05	1.96	8.81%	11.8%
20	BB&T	34.49	0.92	8.36%	11.3%
21	BECTON DICKINSON	99.60	1.98	9.29%	11.5%
22	BEST BUY	29.82	0.68	8.05%	10.5%
23	BRISTOL MYERS SQUIBB	44.75	1.40	8.20%	11.6%
24	BROWN-FORMAN 'B'	69.78	1.02	11.63%	13.3%
25	C R BARD	110.96	0.84	10.02%	10.9%
26	CABLEVISION SYS.	17.51	0.60	10.75%	14.6%
27	CARDINAL HEALTH	49.09	1.21	10.50%	13.2%
28	CHUBB	85.71	1.76	9.97%	12.2%
29	CIGNA	74.14	0.04	10.93%	11.0%
30	CINTAS	46.96	0.64	9.97%	11.5%
31	CISCO SYSTEMS	24.82	0.68	9.10%	12.1%
32	COACH	55.16	1.35	9.79%	12.5%
33	COCA COLA	40.00	1.12	7.90%	11.0%
34	COCA COLA ENTS.	36.62	0.80	9.87%	12.3%
35	COLGATE-PALM.	58.60	1.36	9.00%	11.6%

36	CONAGRA FOODS	35.21	1.00	10.58%	13.7%
37	COSTCO WHOLESALE	113.30	1.24	13.47%	14.7%
38	COVIDIEN	59.58	1.04	8.69%	10.6%
39	CSX	24.61	0.60	12.10%	14.9%
40	DANAHER	64.93	0.10	11.37%	11.5%
41	DEERE	83.41	2.04	8.00%	10.7%
42	DOMINION RESOURCES	57.40	2.25	6.88%	11.1%
43	DOVER	82.14	1.50	12.53%	14.6%
44	DOW CHEMICAL	34.78	1.28	7.63%	11.6%
45	DR PEPPER SNAPPLE GROUP	46.43	1.52	7.53%	11.1%
46	E I DU PONT DE NEMOURS	56.23	1.80	7.73%	11.2%
47	EASTMAN CHEMICAL	75.12	1.20	9.03%	10.8%
48	EATON	66.08	1.68	11.87%	14.7%
49	EMERSON ELECTRIC	58.49	1.64	9.50%	12.6%
50	EOG RES.	142.48	0.75	12.00%	12.6%
51	ESTEE LAUDER COS.'A'	66.84	0.72	12.57%	13.8%
52	EXPEDIA	54.20	0.60	10.97%	12.2%
53	FAMILY DOLLAR STORES	66.64	1.04	11.32%	13.1%
54	FEDEX	104.08	0.60	13.36%	14.0%
55	FIDELITY NAT.INFO.SVS.	44.39	0.88	12.18%	14.4%
56	FLUOR	61.85	0.64	13.53%	14.7%
57	FMC	64.13	0.54	12.05%	13.0%
58	FRANKLIN RESOURCES	47.86	0.39	13.75%	14.7%
59	GARMIN	37.57	1.80	5.57%	10.7%
60	GENERAL ELECTRIC	23.80	0.76	9.80%	13.3%
61	GENERAL MILLS	49.74	1.52	7.90%	11.2%
62	HONEYWELL INTL.	80.51	1.64	10.40%	12.7%
63	HUMANA	87.17	1.08	9.27%	10.6%
64	ILLINOIS TOOL WORKS	71.28	1.68	11.63%	14.3%
65	INGERSOLL-RAND	58.74	0.84	11.03%	12.6%
66	INTERNATIONAL BUS.MCHS.	194.66	3.80	9.96%	12.1%
67	INTERPUBLIC GP.	15.47	0.30	12.42%	14.6%
68	JOY GLOBAL	51.04	0.70	10.33%	11.9%
69	KROGER	36.44	0.60	9.07%	10.9%
70	L BRANDS	54.04	1.20	11.37%	13.9%
71	LINCOLN NAT.	39.34	0.48	9.37%	10.7%
72	LINEAR TECH.	38.72	1.04	10.49%	13.5%
73	LYONDELLBASELL INDS.CL.A	67.96	2.00	11.10%	14.4%
74	MACY'S	47.75	1.00	12.32%	14.7%
75	MARRIOTT INTL.'A'	40.94	0.68	11.80%	13.7%
76	MARSH & MCLENNAN	40.68	1.00	12.10%	14.9%
77	MCDONALDS	97.82	3.08	8.45%	11.9%

78	MEAD JOHNSON NUTRITION	76.76	1.36	9.30%	11.2%
79	METLIFE	46.94	1.10	8.53%	11.1%
80	MICROSOFT	33.64	0.92	8.63%	11.6%
81	MONDELEZ INTERNATIONAL CL.A	30.38	0.56	11.16%	13.2%
82	MORGAN STANLEY	26.03	0.20	10.60%	11.5%
83	NASDAQ OMX GROUP	32.19	0.52	12.33%	14.2%
84	NATIONAL OILWELL VARCO	70.95	1.04	10.37%	12.0%
85	NETAPP	39.95	0.60	13.18%	14.9%
86	NEWELL RUBBERMAID	26.53	0.60	9.37%	11.9%
87	NIKE 'B'	63.20	0.84	11.47%	13.0%
88	NORDSTROM	59.75	1.20	11.08%	13.3%
89	NORTHEAST UTILITIES	42.24	1.47	7.62%	11.4%
90	NVIDIA	14.43	0.30	12.00%	14.3%
91	OMNICOM GP.	63.60	1.60	9.54%	12.3%
92	ORACLE	32.09	0.48	10.68%	12.3%
93	PATTERSON COMPANIES	39.53	0.64	11.33%	13.1%
94	PAYCHEX	38.17	1.40	10.00%	14.1%
95	PEOPLES UNITED FINANCIAL	14.78	0.65	7.41%	12.2%
96	PEPSICO	82.13	2.27	8.30%	11.3%
97	PERKINELMER	34.07	0.28	11.43%	12.4%
98	PHILIP MORRIS INTL.	88.33	3.40	10.13%	14.4%
99	PPG INDUSTRIES	155.03	2.44	8.95%	10.7%
100	PRAXAIR	117.60	2.40	11.10%	13.4%
101	PREC.CASTPARTS	226.94	0.12	13.55%	13.6%
102	PROCTER & GAMBLE	78.20	2.41	8.05%	11.4%
103	PROGRESSIVE OHIO	25.47	0.28	9.95%	11.2%
104	PVH	125.42	0.15	11.90%	12.0%
105	QUEST DIAGNOSTICS	59.96	1.20	12.50%	14.8%
106	RALPH LAUREN CL.A	175.82	1.60	11.25%	12.3%
107	REYNOLDS AMERICAN	49.14	2.52	7.70%	13.3%
108	ROCKWELL AUTOMATION	90.73	2.08	12.10%	14.7%
109	ROCKWELL COLLINS	67.82	1.20	9.55%	11.5%
110	ROSS STORES	66.11	0.68	12.37%	13.5%
111	SCRIPPS NETWORKS INTACT. 'A'	70.23	0.60	14.00%	15.0%
112	SHERWIN-WILLIAMS	176.51	2.00	13.00%	14.3%
113	ST.JUDE MEDICAL	48.43	1.00	8.64%	10.9%
114	SUNTRUST BANKS	33.08	0.40	10.03%	11.4%
115	SYMANTEC	24.31	0.60	8.94%	11.7%
116	TARGET	69.70	1.72	10.71%	13.5%
117	THE HERSHEY COMPANY	91.28	1.94	9.85%	12.2%
118	TIFFANY & CO	77.10	1.36	12.09%	14.1%
119	TIME WARNER	60.36	1.15	12.81%	15.0%

120	TIME WARNER CABLE	110.02	2.60	11.83%	14.5%
121	TJX COS.	51.27	0.58	11.26%	12.5%
122	TRAVELERS COS.	81.75	2.00	8.57%	11.2%
123	UNITED PARCEL SER.'B'	87.15	2.48	11.07%	14.3%
124	UNITEDHEALTH GP.	68.35	1.12	8.78%	10.6%
125	UNUM GROUP	30.14	0.58	8.47%	10.6%
126	US BANCORP	36.50	0.92	9.25%	12.0%
127	V F	191.70	3.48	11.04%	13.1%
128	VIACOM 'B'	71.52	1.20	12.64%	14.5%
129	WAL MART STORES	75.63	1.88	9.10%	11.8%
130	WALT DISNEY	64.15	0.75	12.32%	13.6%
131	WESTERN UNION	17.45	0.50	8.72%	11.9%
132	WYNN RESORTS	133.66	4.00	10.50%	13.8%
133	XILINX	42.57	1.00	9.80%	12.4%
134	YUM! BRANDS	71.49	1.34	11.32%	13.4%
135	Market-weighted Average				12.4%

Notes: In applying the DCF model to the S&P 500, I included in the DCF analysis only those companies in the S&P 500 group which pay a dividend, have a positive growth rate, and have at least three analysts' long-term growth estimates. I also eliminated those 25% of companies with the highest and lowest DCF results, a decision which had no impact on my CAPM estimate of the cost of equity.

D_0 = Current dividend per Thomson Reuters.
P_0 = Average of the monthly high and low stock prices during the three months ending September 2013 per Thomson Reuters.
g = I/B/E/S forecast of future earnings growth September 2013.
k = Cost of equity using the quarterly version of the DCF model shown below:

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130140-EI

GULF POWER

A SOUTHERN COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

AMY D. WHALEY

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Amy D. Whaley
Docket No. 130140-EI
In Support of Rate Relief
Date of Filing: November 6, 2013

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

A. My name is Amy Whaley. My business address is 3500 Lenox Road, Suite 900, Atlanta, GA 30326-4238. I am a Senior Actuarial Consultant for Towers Watson specializing in Health and Group Benefits.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor's of Arts degree from Southern Methodist University with a major in mathematics and a minor in business. I have a Master's of Management Science degree from Georgia State University with an emphasis in Human Resources. I am a Fellow of the Society of Actuaries and a Member of the American Academy of Actuaries. I have been working in health actuarial consulting for over eighteen years.

Q. What types of services does Towers Watson provide?

A. Towers Watson is a leading global professional services company which has about 14,000 associates throughout the world, who offer solutions in areas such as employee benefits, compensation plan design and benchmarking, and talent management. As a health care actuary in Towers Watson's Health and Group Benefits, I am part of a team of over 860 consultants and actuaries. We help clients effectively budget for their health care programs by adjusting their claims experience for factors like the price of health care services, the innovation and adoption of new treatments and technologies, aging and other demographic characteristics, and changes in program design.

Q. Please describe the scope of your expertise as a health actuarial consultant.

A. In my eighteen years as a health actuarial consultant, I have provided consulting advice to organizations ranging from 500 to over 100,000 employees in health and welfare benefit design, strategy, financial projections and budgeting, merger and acquisition due diligence and benefit integration, and employee contribution changes. I also help employers adapt to legislative mandates and changes, including health care reform.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to a recommendation made by Office of Public Counsel (OPC) Witness Garrett related to Gulf Power Company's (Gulf or the Company) employee medical expense projected for the 2014 test year.

Q. Are you sponsoring any rebuttal exhibits?

A: Yes. I am sponsoring rebuttal Exhibit ADW-1, Schedule 1. Exhibit ADW-1, Schedule 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. For whom are you appearing as a rebuttal witness?
A. I am appearing as a rebuttal witness for Gulf.

Q. Do you agree with Mr. Garrett's proposal to reduce employee medical expense?
A. No. Mr. Garrett has proposed reducing employee medical expense by $387,000 based on a fundamentally faulty argument that the Florida Public Service Commission (Commission) should impose a 7 percent health care cost increase limit for Gulf's 2014 test year. Mr. Garrett erroneously contends that his proposal is supported by a nationwide, multi-industry employer survey on health care trends conducted by my firm, Towers Watson.

Q. What is wrong with Mr. Garrett's argument?
A. Mr. Garrett incorrectly applies and misinterprets the information contained in the Towers Watson survey he references.

Q. How is the information presented from Mr. Garrett applied incorrectly?
A. The Towers Watson health care trend data to which Mr. Garrett refers represents the average increase in health care spending among a group of more than 500 employers, representing a wide variety of industries, regions, and health plan offerings. Health care trends for specific employers vary widely, based on factors such as health plan benefit designs, workforce demographics, and industry talent needs. Only 7 percent of the employers from the survey, for example, are in the utility industry. See Exhibit ADW-1,

Schedule 1, which provides a breakdown of the employer participation by industry from the Towers Watson survey cited by Mr. Garrett. There is a wide variety of expected health care cost trends for employers in different industries. The variety of industries in the study cited by Mr. Garrett have drastically different workforces and talent needs than the utility industry (e.g. retail companies, information technology firms and public sector workers) leading to different benefit programs with different health care trends.

Q. Mr. Garrett uses the survey data from 2013 to make his argument. Is 2013 data the best estimate for future trend?

A. No. Estimating health care cost trend for a future year should take into account multiple years of trend information to get a good estimate of what might happen during future years. Looking at only one year of data to project future trends is not sufficient. That one year may be an outlier. If you look at the past six years of results in the Towers Watson survey cited by Mr. Garrett, you see that average trends before plan design and contribution changes range from 6.8 percent to 9.0 percent. See Exhibit ADW-1, Schedule 1, which excerpts data points from the Towers Watson survey cited by Mr. Garrett.

Q. How was the information presented by Mr. Garrett misinterpreted?

A. The trend that Mr. Garrett references of "5-7 percent" is a trend based on a multi-industry, nationwide employer survey. For Gulf, Aon Hewitt more appropriately adjusted the trend to reflect Gulf's specific details, such as plan provisions, employee contributions, and health care reform.

Q. What are examples of adjustments made due to health care reform in Gulf's projected health care costs that would not be reflected in the survey cited by Mr. Garrett?

A. The 10 percent trend for 2014 appropriately includes adjustments related to the Affordable Care Act, such as the individual mandate and transitional reinsurance fee, both of which are projected to increase expenses to employers. These adjustments were not reflected in the Towers Watson employer survey cited by Mr. Garrett.

Q. Are Aon Hewitt's projected health care trend numbers for Gulf reasonable?

A. Yes. Health care trend increases of 8.5 percent and 10.0 percent properly reflect the expected increase in employer cost for Gulf Power, after considering impacts of health care reform. The 8.5 percent and 10 percent health care trend projected by Aon Hewitt are consistent with Gulf's health care plans, rather than the generic, multi-industry 7 percent trend that Mr. Garrett proposes.

Q. Is it appropriate to project Gulf's health care costs for the 2014 test year using the Towers Watson survey cited by Mr. Garrett?

A. No. Towers Watson did not design the survey cited by Mr. Garrett to be used by an individual utility such as Gulf to project its particular health care costs for 2014. Gulf's individual plan designs, as well as its health care experience and population demographics, are important factors to be taken into consideration when projecting its health care costs for 2014.

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

Exhibit

Florida Public Service Commission
Docket No. 130140-EI
GULF POWER COMPANY
Witness: Amy D. Whaley
Exhibit No. ___(ADW-1)
Schedule 1
Page 1 of 1

Towers Watson - Data Excerpts from
Reshaping Health Care, The 18th Annual Towers Watson/National Business Group Health Employer Survey on Purchasing Value in Health Care (2013)

Multi-Industry Annual trends

Year	Trend After Plan and Contribution Changes	Trend Before Plan and Contribution Changes
2013	5.1%	7.0%
2012	5.2%	6.8%
2011	5.4%	8.0%
2010	6.0%	8.0%
2009	7.0%	8.0%
2008	6.0%	9.0%

Survey Respondent Information

Region*	Percent
National	25%
Northeast	24%
South	13%
Midwest	23%
West	15%

Respondents	Total Number
Employers	583

Industry Group	Percent**
Energy and Utilities	7%
Financial Services	16%
General services	8%
Health Care	13%
IT and Telecom	11%
Manufacturing	30%
Public Sector and Education	4%
Wholesale and Retail	9%

*where majority of benefit-eligible workforce is located
**numbers may not add due to rounding differences