BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR INCREASE IN RATES BY GULF POWER COMPANY. /

DOCKET NO. 110138-EI

VOLUME 9

Pages 1524 through 1737

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PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER LISA POLAK EDGAR COMMISSIONER RONALD A. BRISÉ COMMISSIONER EDUARDO E. BALBIS COMMISSIONER JULIE I. BROWN
DATE:	Wednesday, December 14, 2011
TIME:	Recommenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR, FPR
APPEARANCES:	(As heretofore stated.)

I N D E X

WITNESSES

INDEX TO EXHIBITS

P R O C E E D I N G S

(Transcript continues in sequence from Volume 8.)

CHAIRMAN GRAHAM: Next witness.

MR. SAYLER: Mr. Chairman, the Office of Public Counsel would call Helmuth W. Schultz III to the stand.

And, Mr. Chairman, just like Mr. McGlothlin stated, we passed out three other exhibits, and these are various errata to the other witnesses. If you would like, we can maybe identify those now at this time or do them with each witness as they come in. It's at your pleasure.

CHAIRMAN GRAHAM: We'll do it with each witness, but we'll give this one right now 206. Do you have a description for it?

MR. SAYLER: Errata to direct testimony and subsequent revised schedules, or maybe errata to testimony of Schultz.

CHAIRMAN GRAHAM: Errata to direct testimony for Schultz.

MR. SAYLER: With schedules.

(Exhibit Number 206 was marked for identification.)

Thereupon,

HELMUTH W. SCHULTZ III

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. SAYLER:

Q. Good morning, Mr. Schultz. Have you been previously sworn?

A. Yes, I was sworn in yesterday.

Q. All right. Would you please state your name and business address for the record.

A. My name is Helmuth W. Schultz III. My business address is Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan.

Q. And you are employed by Larkin & Associates?

A. Yes, I am.

Q. And in what capacity?

A. I am a senior regulatory analyst.

Q. All right. On behalf of the Office of Public Counsel, did you prepare and submit direct testimony in this proceeding on October 14, 2011?

A. I did.

Q. And do you have that testimony with you?

A. I do.

Q. And do you have any corrections or revisions to make to your prefiled direct testimony?

A. I do.

Q. And are these shown in the exhibit labeled 206?

A. They are, with the exception of one additional errata that I noted in flight here.

THE COURT: All right. Mr. Chairman, would you like him to go through the errata in the exhibit or --

CHAIRMAN GRAHAM: (Shaking head.)

MR. SAYLER: Okay.

BY MR. SAYLER:

Q. Well, with the exception of the errata in your exhibit, would you let us know what the changes to your testimony that is not on this exhibit sheet?

A. On page 32, line 24 --

Q. Yes, sir.

A. The words "over the" should be deleted.

Q. Okay. Any other changes to your direct prefiled testimony?

A. No, that takes care of all of them.

Q. All right. And as modified and corrected by this exhibit and your oral modification, do you adopt the prefiled testimony as your testimony today?

A. I do.

MR. SAYLER: All right. Mr. Chairman, I ask that the prefiled testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Schultz's testimony, prefiled direct testimony into the record as though read.

DIRECT TESTIMONY

OF

Helmuth W. Schultz, III

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 110138-EI

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Helmuth W. Schultz, III. My business address is 15728 Farmington Road, Livonia Michigan 48154.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Senior Regulatory Analyst with Larkin & Associates P.L.L.C.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCITES, P.L.L.C.

A. Larkin & Associates, P.L.L.C. performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney generals, etc.). Larkin & Associates, P.L.L.C., has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including water and sewer, gas, electric and telephone utilities.

Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Yes, I have attached Exhibit No. ___ (HWS-1), which is labeled H.W. Schultz, III Schedules, and contains Schedules C-1 through C-4. Also attached as Exhibit No.__(HWS-2), entitled Qualifications of Helmuth W. Schultz, III, is a summary of my background, experience and qualifications.

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Larkin & Associates, P.L.L.C., was retained by the Florida Office of Public Counsel ("OPC") to review the rate increase requested by Gulf Power Company ("Company" or "Gulf"). Accordingly, I am appearing on behalf of the citizens of Florida ("Citizens") who are customers of Gulf.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE THE ISSUES YOU WILL BE ADDRESSING IN THIS PROCEEDING.

A. I am addressing the appropriateness of the Company's recovery on Plant Held for Future Use for the land and costs for a possible nuclear facility, the annual expense for the storm reserve accrual, tree trimming, pole inspections, production maintenance and the recovery of Directors and Officers Liability ("DOL") Insurance.

III. PLANT HELD FOR FUTURE USE-NUCLEAR SITE COST

Q. WOULD YOU PLEASE DESCRIBE GULF'S REQUEST TO INCLUDE AN ADDITIONAL $26,751,000 (JURISDICTIONAL) OF PLANT HELD FOR FUTURE USE ("PHFU") IN THE RATE BASE FOR RECOVERY FROM RATEPAYERS?

A. Yes. The Company has deferred approximately $27.7 million ($26.7 jurisdictional) in costs it has incurred for procuring a 4,000 acre site in North Escambia County to "preserve a nuclear option for its customers." The Company indicated that this site is suitable for other generation technologies as well. The Company is now requesting to cease deferring these costs and include them in rate base as PHFU. As can be seen on Mr. McMillan's Schedule 2, page 2 of 2, line 9, the Company's proposed increase to PHFU is $27.687 million on a total company basis and $26.751 million on a jurisdictional basis. According to the Company's response to Staff's Fifth Set of Interrogatories, No. 47, the total Company amount is comprised of approximately $19 million for site acquisition costs; $4.5 million for site investigation costs; $1.2 million for legal fees, project support costs, and generation studies, and "Project Frank"; and an additional $3.0 million of Allowance for Funds Used During Construction ("AFUDC") carrying costs. It is unclear as to whether the costs other than land costs have been incurred or are instead projected to be incurred.

Q. WHAT IS THE CURRENT DOLLAR AMOUNT OF PHFU INCLUDED IN THE COMPANY'S RATE BASE?

A. On a total Company basis, the amount of PHFU included in rate base prior to the nuclear site cost adjustment is $5,665,000. The jurisdictional amount is $5,482,000.

Q. **WHAT EFFECT WOULD THE INCLUSION OF THE COMPANY'S REQUEST TO INCREASE PHFU HAVE ON THE COMPANY'S REVENUE REQUIREMENT?**

A. Based on the Company's requested rate of return, the current jurisdictional amount of PHFU translates to an approximate revenue requirement of $632,000 annually. If the Commission approves Gulf's request, the jurisdictional revenue requirement that would be associated with adding the $26.7 million to rate base as PHFU is $3,083,000, as shown on Mr. McMillan's Schedule 2, page 2 of 2, line 9, column 4. Including the Company's requested increase to PHFU would increase the revenue requirement for ratepayers associated with PHFU by approximately 487%. Therefore, this increase would increase the current revenue requirement associated with PHFU from approximately $632,000 to a total of $3,715,000.

Q. **HAS GULF PROVIDED A BASIS FOR INCLUDING THIS SIGNIFICANT INCREASE IN PLANT HELD FOR FUTURE USE IN CURRENT RATES TO BE RECOVERED FROM RATEPAYERS?**

A. Gulf has provided arguments, which I discuss below, that are not supported by any studies or other information which would justify the inclusion of such a significant increase in PHFU in rate base and recovered from ratepayers.

Q. WHOSE TESTIMONY SUPPORTS THE INCLUSION OF THIS LARGE DOLLAR AMOUNT IN PHFU?

A. Company witnesses McMillan and Burroughs both include arguments purporting to support this investment as being prudent and reasonable for inclusion in rate base.

Q. WOULD YOU DISCUSS EACH OF THE WITNESSES' TESTIMONY AND THE ARGUMENTS THEY PRESENT?

A. Yes. Mr. McMillan refers to Section 366.93, Florida Statutes, ("F.S."), as justification for including this dollar amount of PHFU in rate base and makes the following statement in his direct testimony: "In deciding to pursue consideration of nuclear generation, Gulf relied on the recovery provided by this statute."

Q. WHAT IS YOUR UNDERSTANDING OF SECTION 366.93, FLORIDA STATUTES?

A. Section 366.93, F.S. provides for "cost recovery for the siting, design, licensing and construction of nuclear and integrated gasification combined cycle power plants." It is my understanding that this statute allows a utility to petition the Commission for recovery of costs related to either a nuclear plant or an integrated gasification combined cycle plant through the utility's capacity cost recovery clause. I have been informed by Counsel for the OPC, of OPC's opinion that this statute does not apply to the Gulf's request. Section 366.93(3), F.S, states that "<u>After a petition for determination of need is granted, a utility may petition the Commission for cost recovery as permitted by this section and the Commission's rules.</u>" (Emphasis added). Counsel for OPC has informed me that the

Commission implemented this provision with a rule that provides for recovery of certain costs via a cost recovery clause that is separate from base rates. Thus, it is only after the need determination for the plant has been approved by the Commission will cost recovery be included under the nuclear cost recovery statute, and such recovery would take place outside of base rates. Therefore, Gulf's attempt to invoke Section 366.93, F.S. fails.

Q. HAS GULF FILED A PETITION FOR DETERMINATION OF NEED?

A. No. Gulf has not requested or filed a petition for determination of need. In response to Citizens Interrogatory No. 24 the Company stated the following:

> ...the Company does not currently have a need to construct generation facilities; therefore, the Company does not plan to file a petition for determination of need for a nuclear plant (or any generation) in the near future.

Since Gulf admits that it does not plan to file a petition for determination of need for a nuclear plant in the near future, the Company's purchase of this site is based on nothing more than speculation that nuclear generation *might* be a viable option for its customers at some time in the future. Further, because no petition has been filed for a determination of need which satisfies the requirements of Section 366.93(3), F.S., the costs associated with the purchase of this land should not be included in PHFU pursuant to Section 366.93, F.S.

Q. MR. MCMILLAN ALSO STATES THE FOLLOWING: "GULF BELIEVES THAT NUCLEAR IS A VIABLE OPTION THAT BENEFITS CUSTOMERS UNDER A RANGE OF SCENARIOS." HAS GULF IDENTIFIED THESE VIABLE OPTIONS TO WHICH MR. MCMILLIAN

REFERS IN A NEED DETERMINATION PETITION TO THE FLORIDA PUBLIC SERVICE COMMISSION?

A. I do not believe so. I am unaware of any petition that Gulf has filed with the Commission to justify any nuclear expansion of its generating facilities. As previously mentioned, a petition for "determination of need" must be granted before the Company can petition the Commission for cost recovery as permitted under Section 366.93, F.S. The Company has not filed any such needs petition or studies regarding the "range of scenarios" to which Mr. McMillan refers.

Q. **HAS GULF DEMONSTRATED THAT THE ADDITION OF A NUCLEAR UNIT TO GULF'S GENERATING PORTFOLIO MAKES ANY SENSE FROM AN OPERATIONAL STANDPOINT?**

A. No. The following observations are based as much on common sense as any technical analysis. Logically, the unit added by a utility should match the requirements that the utility has demonstrated are necessary to meet the demand and energy requirements which are projected for the utility cost-effectively. Gulf has not presented any documentation, studies, or analyses which satisfy this general rule. Second, most nuclear units that have been proposed are in the range of 1,200 megawatts, which would result in a net generation capacity addition to the system of about 1,150 megawatts. Gulf's 2010 system peak was 2,553 megawatts. A unit of this size could be 45% of Gulf's system peak. The peak load on the Gulf system through July 31, 2011was 2,495 megawatts. If this nuclear unit's net generation is 1,150 megawatts that would equate to 46% of that 2011 year-to-date peak. I am not aware of any electric utility that has a single unit that amounts to that large of a percentage of the system peak.

Q. ARE YOU AWARE OF ANY COMPANY THE SIZE OF GULF WHICH HAS LESS THAN 500,000 CUSTOMERS THAT HAS CONSTRUCTED A NUCLEAR PLANT FOR ITS OWN USE?

A. No, I am not. I asked the Company if it was aware of any company with less than 500,000 customers that had constructed a nuclear plant for its own use. Gulf's answer to Citizens Interrogatory No. 109 was "Gulf does not know whether any company with less than 500,000 customers has constructed a nuclear plant for its own exclusive use." It would seem that since the Company has contemplated construction of a nuclear plant, that it would have investigated to see if any company of a similar size has a nuclear plant, and whether that nuclear plant has been economic for its customers.

It is also my understanding that much larger utilities in Florida, namely Florida Power & Light and Progress Energy Florida, have been delaying the construction of nuclear plants further into the future because they cannot be justified on the basis of need. It is hard to believe that Gulf, a company far smaller than these two companies, could justify a nuclear plant for its own needs at any time.

Q. DID THE COMPANY INDICATE THAT IT MIGHT SEEK OTHER PARTICIPANTS TO CO-OWN THE FACILITY?

A. Yes. In its response to Citizens Interrogatory No. 109, part "e", the Company stated:

> Depending on the actual type and timing of an eventual generating resource addition constructed on the site, Gulf may seek the participation of potential co-owners in order to facilitate the addition. Such co-owners may potentially be other companies within the Southern electric system or unaffiliated companies.

Q. IF THAT IS THE CASE AND GULF DOES SEEK OTHER CO-OWNERS WHEN AND IF THIS SITE IS EVENTUALLY USED, WOULD THAT JUSTIFY ITS INCLUSION IN THE COMPANY'S RATE BASE?

A. No, it supports just the opposite conclusion. Gulf does not anticipate needing capacity until the year 2022, when the current resource plan indicates that 30 megawatts might be needed. If Gulf were to add 1,150 megawatts of net nuclear generating capacity to meet its need, its reserve margin would be approximately 40%. This would suggest that Gulf cannot seriously regard nuclear expansion for Gulf's needs only. If a nuclear unit ever makes sense, it will be in the context of shared ownership or sales to other entities. If the cost of this land were added to the rate base using the Company's requested rate of return, the annual carrying cost would be $3,083,000. Over the 10-year period between January 2012 and January 2022, the earliest year in which Gulf projects a need for capacity (and not necessarily the date that Gulf would target as the in-service date of a nuclear unit), ratepayers would have paid $30,830,000 in carrying charges on this piece of property, which Gulf admits may have other co-owners in order to build a nuclear plant. In other words, if Gulf is allowed to place the property in rate base now, Gulf ratepayers would be subsidizing some future owner of this property if and when a nuclear unit is ever built. Viewed strictly from the perspective of Gulf's ratepayers, the idea of Gulf pursuing a nuclear unit makes no sense at all.

Q. WOULD YOU PLEASE DISCUSS THE COST WHICH THE COMPANY HAS INCLUDED IN THE PLANT HELD FOR FUTURE USE WHICH IT SEEKS TO RECOVER A CARRYING CHARGE FROM RATEPAYERS?

A. Yes. The total Company dollar amount which it seeks to put in rate base is $27,687,440. Of this amount approximately $4.5 million is cost incurred for site investigation. It appears that most of these costs were (or will be) incurred to determine whether this property would be suitable for a nuclear plant. It would not seem appropriate to charge ratepayers for costs such as these if the Company contemplates other parties sharing in the ownership of this plant. In addition, the Company has included an amount of approximately $187,000 which it has entitled "Needs Determination Filing." As of the date of this filing, Gulf has no docket opened to address any such nuclear need determination before the Florida Public Service Commission. Regardless, the need determination filing costs are not appropriate costs to include in Plant Held for Future Use.

In addition, approximately $650,000 of costs were incurred by Southern Company and Gulf for travel expenses, resource planning, and legal fees. Again, these costs seem extremely high given the fact that there is no definite plan, nuclear or otherwise, for this piece of property. Finally, there is a cost which is labeled "Project Frank" which has no other explanation. This cost is approximately $370,000. These costs likewise are not appropriate costs to include in Plant Held for Future Use.

Q. **DOES THE COMMISSION HAVE A STANDARD THAT IT APPLIES WHEN IT ALLOWS PROPERTY TO BE INCLUDED IN PHFU?**

A. By Order No. 5471 in Docket No. 71342-EU, issued June 30, 1972, the Commission considered the issue of whether to include costs associated with the Caryville plant site. The Commission stated the following:

> . . . we conclude that so long as the acquisition of the property in question is considered a responsible and prudent investment and it appears that it will be used for utility purposes in the reasonably near future, in the light of prevailing conditions, such property should be included in the utility's rate base."

This statement was made in support of including the Caryville site in PHFU. This approval was in 1972, 39 years ago. The Caryville site still has not been utilized and the Company does not have any disclosed plans to use this site. Given availability of the Caryville site, it is not be appropriate to include such a huge dollar amount for the proposed Escambia site when the need for such an additional site has not been proven. In my opinion, the acquisition of the Escambia site does not appear to be a reasonable and prudent investment that will be used for Gulf's system purposes in the *reasonably* near future.

Q. IN ITS RESPONSES TO INTERROGATORIES, DIDN'T GULF INDICATE THAT THIS PROPERTY COULD BE USED FOR GENERATION UNITS OTHER THAN NUCLEAR?

A. Yes. In response to Citizens Interrogatory No. 109, Gulf stated in sub-part "a":

> Gulf anticipates that this site will accommodate a wide range of future capacity additions from conventionally fueled baseload, or intermediate generation facilities to facilities that utilize renewable fuels.

This, however, does not justify ratepayers paying a substantial carrying charge on this large piece of property. Currently, Gulf has two pieces of property on which ratepayers have been paying a carrying charge for several years. They are available for construction of conventional generating facilities.

Q. PLEASE DESCRIBE THE OTHER PIECES OF PROPERTY INCLUDED IN PHFU BY GULF.

A. The Caryville site, previously discussed, consists of approximately 2,200 acres in Holmes County, Florida, with a book value of $1,356,000 and has been in PHFU since September 19, 1963. Company witness Burroughs states that the Caryville site has been certified under the Power Plant Siting Act for a steam electric generating plant. The Company has another site which has been in PHFU since October 22, 1998. The Mossy Head property is 250 acres and has a cost of $296,000.

Q. WAS GULF ASKED TO STATE THE AMOUNT OF CAPACITY WHICH COULD BE BUILT ON THESE SITES?

A. Yes. In Citizens Interrogatory No. 106, Gulf was asked the amount of capacity which could be built on each of the land sites listed on MFR Schedule B-15. Gulf's response was:

> The amount of capacity that could be built on a particular site would be determined by the generation technology chosen and Gulf's capacity needs at the time the generation site is developed.

The Company did not provide any information regarding its plans with these two sites and what amount of capacity would be available to the Company. However, I have seen old orders of the Commission indicating that in the 1970s Gulf intended to construct a 500 MW coal-fired unit at Caryville, so the capacity of the site is at least 500 MW. Ratepayers have paid and continue to pay a carrying charge on these two pieces of property since the Commission has allowed them to be included in rate base.

Q. PLEASE ELABORATE ON THE ORDER WHICH INDICATES THAT THE COMPANY INTENDED TO BUILD A 500 MEGAWATT COAL FIRED GENERATING STATION AT THE CARYVILLE SITE.

A. By Order No. 7453, issued September 30, 1976, in Docket No. 760605-EU, the Commission noted Gulf's plans to construct a 500 megawatt coal-fired unit near Caryville, Florida, with a projected completion date in 1982. That unit was never constructed at the Caryville site, thus the Caryville site is still available for at least a 500 megawatt unit.

Q. ARE YOU AWARE OF ANY LARGE STEAM GENERATING POWER PLANTS THAT ARE SITED ON PROPERTY THE SIZE OF THE 2,200 ACRES OF THE CARYVILLE SITE?

A. Yes. Detroit Edison's Monroe County Plant is located in Michigan and is sited on 1,200 acres of property and has a summer capacity of 3,129 megawatts. It appears that the 2,200 acre Caryville site, which was previously approved for coal-fired generation, could hold a substantial amount of capacity which could be used by Gulf Power.

Therefore, with the availability of the Caryville site, Gulf's argument that the 4,000 acre Escambia property would be available for siting of generation other than nuclear does not support its request to be included in PHFU. The fact the Company has held the Caryville property since 1963 and has not put that property into service is evidence that Gulf does not need to acquire the Escambia site or place it into rate base as LHFU. Additionally, the smaller Mossy Head site consisting of 250 acres could at least accommodate a combustion turbine generating unit.

Q. MR. MCMILLAN ALSO STATES "THE PURCHASE OF THIS SITE IS THUS NECESSARY TO ALLOW GULF TO PRESERVE A NUCLEAR OPTION FOR ITS CUSTOMERS." HAS GULF PRESENTED ANY STUDIES TO THIS COMMISSION THAT SHOW THE NECESSITY FOR ADDITIONAL CAPACITY AND HAVE THOSE STUDIES SHOWN THAT NUCLEAR ENERGY WOULD BE AN OPTION?

A. No. If Gulf has participated in such studies with its parent company, Southern Company, those studies have not been presented to the Florida Public Service Commission. It would not be appropriate for the Commission to include these substantial PHFU costs in rate base supported solely by what can only be described as the Company's speculative overreaching. Only other affiliate or non-affiliate utilities could benefit from a decision to allow Gulf to collect now the full costs of a 4,000 acre site for a nuclear plant that, without the joint ownership and/or participation of others, would surely "engulf" its customers.

Q. WHAT ARGUMENTS DOES COMPANY WITNESS BURROUGHS MAKE TO JUSTIFY THE INCLUSION OF THIS SIGNIFICANT COST IN PHFU?

A. Mr. Burroughs refers to the same underlying justification that Mr. McMillan offered. He states "Gulf Power evaluates a variety of generation resources to meet future needs." It is, however, inescapable that the Company's evaluations, which it states underlies the inclusion of this land in PHFU, have never been presented to the Florida Public Service Commission or any other party for scrutiny. He further states, "This broad technological evaluation has implications in Gulf's approach to land held for future use." If by that he means Gulf's approach has changed such that the acquisition of 4,000 acres of land at a cost of $27 million precedes any technical analysis, I submit that shift is not a prudent one for which customers should bear the costs. There is, however, no study, evaluation or process that the Company has provided to the Commission to justify such a substantial addition to PHFU. Mr. McMillan admits on page 23 of his testimony that recent generation resource additions have not required the use of any Gulf-owned power plant sites and that the 10-year site plan does not reflect a need for capacity until the year 2022. The response to Citizen's Interrogatory No. 108 states that the 10-year site plans shows a "potential" generation need of approximately 30 MW in 2022. This amount hardly justifies the addition or construction of a nuclear plant with 1150 MW of capacity, or the recovery in PHFU for $26 million in unneeded future plant.

Q. **WHAT OTHER ARGUMENTS DOES MR. BURROUGHS MAKE TO SUPPORT THE INCLUSION OF SUCH A LARGE DOLLAR AMOUNT IN PHFU?**

A. Mr. Burroughs basically makes three arguments to support the increase to PHFU. The first is that by buying this piece of land and including it in Gulf's rate base it provides planning flexibility, allowing Gulf to ". . . avoid having to commit to specific generation technologies during a time of high uncertainties associated with potential environmental requirements." This argument does not seem to comport with the Company's justification for inclusion of this land in rate base. The Company states that they are purchasing this land to "allow Gulf to preserve a nuclear option for its customers."[1] It seems that the underlying premise of Mr. McMillan's testimony is that the purchase preserves the nuclear option for the Company and its recovery is based on Section 366.93, F.S. even though there has been no determination of need issued by the Florida Public Service Commission for a nuclear plant in the Gulf service territory. Mr. McMillan's reference to "flexibility" and his acknowledgement that the review of generation technologies has not taken place undermines Gulf's contention that the site selection process for building a nuclear unit has advanced to the point that Gulf is entitled to recover site selection costs from customers.

Mr. Burroughs states that "There are major environmental initiatives being proposed that could change the face of the electric utility industry," and "Gulf's prospective need for new generation may not be limited to just system growth, but could involve the retirement of existing resources driven by regulatory changes." The Company did not provide any studies, analyses, documents or other support which show that a nuclear plant would be necessary to address such regulations if and when they were ever implemented. It appears that the underlying basis for Mr. Burroughs' argument for including this significant cost in rate base is speculative, and not based on any known and measurable standard which is normally used to justify including costs in utility rates.

Q. HAS GULF, THROUGH MR. MCMILLAN OR MR. BURROUGHS, PRESENTED ANY ANALYSIS OR JUSTIFICATION THAT A NUCLEAR PLANT WOULD BE NECESSARY TO MEET EITHER ENVIRONMENTAL REGULATIONS OR SYSTEM GROWTH?

[1] McMillan Testimony, p. 5, line 21.

A. No, and even if they did, a base rate case is not the appropriate forum in which to examine future plant growth and needs. Mr. Burroughs further states, "Although there are many uncertainties, it is clear that there are situations in which nuclear could be a cost-effective solution for meeting long-term additions." Again, Gulf has not presented these situations to the Commission in the form of a petition for determination of need in order to justify any future generation additions or that nuclear, could in reality, be cost-effective in serving Gulf's ratepayers.

Q. YOU ARE RECOMMENDING THAT THE COMMISSION NOT ALLOW GULF TO INCLUDE THE ESCAMBIA SITE IN RATE BASE. SHOULD THE COMMISSION ALLOW THE COMPANY TO CONTINUE ACCRUING AN AFUDC RETURN ON THE SITE?

A. No. Gulf has presented no basis on which the Commission could conclude that this site could ever be used cost-effectively to benefit Gulf ratepayers. The Company has two sites, Caryville and Mossy Head, which have been in PHFU since 1963 and 1998, respectively. Today Gulf has no specific plans to construct capacity on either of them. Gulf has not shown that the Escambia site is a reasonable and prudent investment that will be used for utility purposes in the *reasonably* near future. To allow the Company to accrue AFUDC on an additional 4,000 acres is not justified from the standpoints of reasonableness and prudence. Thus Gulf should not be allowed to accrue any carrying costs on the Escambia site.

IV. STORM RESERVE ACCRUAL AND RESERVE BALANCE

Q. DID YOU REVIEW THE COMPANY'S REQUEST FOR AN INCREASE OF $3.3 MILLION IN THE ANNUAL STORM ACCRUAL?

A. Yes. Gulf witness Constance Erickson recommends an annual accrual of $6.8 million on a system basis and $6.539 million on a retail basis. The intent is to maintain a reserve of between $52 million and $98 million. The accrual amount and the requested reserve are based on an analysis performed by EQECAT Inc., an ABS Group Company.

Q. WHAT CONCERNS ARE THERE WITH THE COMPANY'S REQUEST FOR AN INCREASE IN THE ANNUAL STORM ACCRUAL?

A. The Company's request to adjust the storm reserve is excessive based on the historical charges to the reserve that are intended to be covered by the reserve. Additionally, the request is not adequately justified by the Company based on the storm standards established for Florida electric utilities. Since the expiration of the storm surcharge in June of 2009, and also due to the low level of storm charges against the reserve since 2005, the Company's reserve has increased significantly. In fact, Company witness Erickson states in her testimony that assuming that no property damage is charged during 2011, the reserve will have a balance of $31,093,000 at the beginning of the test year. The level of $31,093,000 would be just above the mid-point of the Commission's target level of $25.1 million to $36 million for the reserve set in Docket No. 951433-EI.[2]

[2] See Order No. PSC-96-1334-FOF-EI, issued November 5, 1996, In Re: Petition for approval of special accounting treatment of expenditures related to Hurricane Erin and Hurricane Opal by Gulf Power Company.

That suggests the current annual reserve accrual is sufficient, if not excessive, for the future. I would also like to note that the purpose of the reserve is not limited to storm protection. It also covers other events not covered by typical insurance protection. In my discussion of charges against the reserve I will address only those costs that are storm charges.

Q. DID THE COMPANY USE ANY STUDIES TO DETERMINE THE LEVEL OF ACCRUAL THAT SHOULD BE MADE?

A. No. Even though the Company's witness Erickson states at page 29 of her direct testimony that "The $6.8 million represents the expected average annual storm loss to be charged to the reserve according to Gulf's 2011 Hurricane Loss and Reserve Performance Analysis (Storm Study)", it is my opinion that the storm study was not used to determine the level of the proposed accrual. Instead, the study reflects what the Company decided it wanted to collect in rates. My opinion is based on my concerns with the focus of the study, the assumptions made, recent history and the conclusions that resulted from the study. There is also a concern with what was not factored in the study.

Q. WHAT IS THE CONCERN WITH THE FOCUS OF THE STUDY?

A. The study indicated that damage level of $8.3 million was based on thousands of random variable hurricanes, an initial reserve of $27 million, losses assumed to increase at 4% per year, a continued annual reserve accrual of $3.5 million, and an expected annual charge of $6.8 million. No alternative assumptions were used as inputs; therefore, it appears that the conclusion (that the only way to adjust the accrual was to increase it) was pre-determined. This was essentially confirmed in the response to Citizens' Interrogatory 206, which states that "There is only one Expected Annual Damage (EAD) calculated", and "Only one storm reserve simulation was performed."

Concern also exists with the fact that the focus was on thousands of storms, including storms as significant as Ivan and Dennis. It should be noted that the probability results shown on Table 4-1 of the study are not based on historical storms but simulated storms (See Gulf's response to Citizens Interrogatory No. 207). While I do believe that historical storm information is relevant, there is a problem with the use of simulations of thousands of storms that were not specific to the Gulf service territory. Storm impacts vary depending on geographic area. According to the response to Citizens Interrogatory No. 210, the Company does not have storm data available by zip code. That would mean there is no support for the damage values incorporated into the study. There is also the fact that the study would include the impact of Ivan and Dennis without performing an alternative damage calculation that excludes Ivan and Dennis.

Q. **WHY IS THERE A CONCERN WITH INCLUDING STORMS LIKE IVAN DENNIS AND KATRINA IN THE DETERMINATION OF DAMAGES CHARGED AGAINST THE STORM RESERVE?**

A. In its storm cost recovery decision for Progress Energy, the Commission stated that the 2004 hurricane season was "unprecedented and extraordinary in nature" and the incremental costs of the 2004 hurricanes did not constitute a base rate item. That means storms of the magnitude of Ivan, Katrina, and Dennis were also not intended to be covered by the reserve in and of itself. The Commission allowed a storm surcharge because the types of storms that occurred during that time frame were extremely unusual and the impact from them was extraordinary. Allowing costs associated with infrequent storms of that magnitude to be factored into the size of the reserve inappropriately requires ratepayers to provide funding for damages that likely will occur only rarely, if at all. If such an event does occur in the future, the mechanism of the surcharge will be available at that time.

Q. WHAT ARE YOUR CONCERNS WITH THE ASSUMPTIONS INCORPORATED IN THE STUDY?

A. The study prepared for the Company determined an average annual loss of $8.3 million of which $6.8 million would be charged against the reserve. This assumption coupled with the assumption of random storms not specific to the Gulf service territory significantly impacted the determination of the estimated reserve results. According to the study (Page 1-1), the loss was computed "using the results of thousands of random variable storms." This is exactly what was deemed a concern with the previously mentioned Progress Energy Florida hurricane study. As indicated earlier, the use of storm data that may be applicable to areas outside of the Gulf service territory will skew the results. There is also the fact that since 2001, with the exception of 2004 and 2005, the Company has charged only $0 to $2.6 million to the reserve for storms in any one year, or an average of $575,566. This average is calculated on Exhibit HWS-1, Schedule C-1, Page 2 of 2.

The study at page 10 emphasizes how the impacts of Hurricanes Ivan, Dennis and Katrina were factored into the loss model. It specifically states, "The 2004-2005 loss history is believed to be most reflective of the current Gulf hurricane restoration practices and cost experience." That assumption as described is not appropriate for two reasons. First, the reserve is for major storms that are not considered extraordinary. Second, the Company has been under direction from the Commission to perform storm hardening at a heightened level since the 2004-2005 extraordinary storms occurred. To base the results of the study on 2004-2005 practices and cost experience ignores the improvements focused on since the 2004-2005 storms, as well as the intended purpose of the reserve.

Q. WHY HAVE YOU EXCLUDED 2004 AND 2005 FROM THE AVERAGE YOU CALCULATED?

A. The 2004 and 2005 storms were extraordinary. After application of the then current storm reserve balance, the costs were recovered through a storm surcharge. In PEF's Storm Cost Recovery proceeding (Docket No. 041272-EI[3]), the Commission stated, "PEF contends that the costs of severe storms like the 2004 hurricanes are too volatile, irregular in their occurrence, and unpredictable to be addressed in base rates." That served as a basis for treating the storm surcharge recovery mechanism as a vehicle for storms of an extraordinary nature. Yet, the Company has attempted to justify its storm request based on a study that did factor in the impacts of those storms.

Q. WHAT ARE YOUR CONCERNS WITH THE COMPANY'S CONCLUSION REGARDING THE STUDY?

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[3] See Order No. PSC-06-0772-PAA-EI, issued September 18, 2006, in Docket No. 041272-EI, In Re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.

A. Ms. Erickson states in her testimony that, based on the updated study, the Company's current accrual of $3.5 million on a system basis, and an estimated annual charge for damages of $6.8 million, the expected fund balance in five years will decline to $11 million. Ms. Erickson then adds that there is 29 percent probability that the fund will become negative within the next five years. There are multiple problems with these hypothetical assumptions. First, absent another occurrence of storms like Ivan, Dennis and Katrina impacting the Gulf service territory, the average annual charges were only $575,566 over an eight year period. That annual average charge is significantly less than the annual $6.8 million assumed and requested by the Company. Second, if one assumes no storm charges through the end of 2011 (i.e. the reserve balance would be $31.1 million), the annual charges over the next five years continue at $575,000 and the Company is allowed a $6.8 million accrual, the result would be a $62.2 million reserve balance as of December 31, 2016. This calculation is shown on Exhibit HWS-1, Schedule C-1, Page 2 of 2. Based on the Company's study there would be only a 4% chance of a storm with a $60 million damage layer occurring that would deplete that reserve. Third, assuming no storms occur for the remainder of 2011, resulting in charges against the reserve through December 31, 2011, the current accrual will have established a reserve of $31.1 million. Based on the Company's study, there is only an 8% chance a storm with a $30 million damage layer occurring and eliminating that reserve. Fourth, the written body of the study suggests a result based on an unsupported and atypical annual average for typical storm reserve damage charges. It assumes a very pessimistic, significant storm occurrence that would result in a possible $111 million negative reserve. For a storm to result in a negative $111million balance there would have to be $140 million of damage (i.e. eliminating the $30 million reserve and resulting in the negative balance). The Company study suggests there is a 1% probability of that happening. The fact is the same study indicates that there is a 24.5% chance that damages could be $500,000 or less. Fifth, the 24.5% probability that $500,000 or less of damage could occur is comparable to the historical damages charged for typical reserve charges between 2001 and 2010. This is further corroborated by the 2011 damages that have been zero to date. Finally, as indicated earlier, the $6.8 million request was a predetermined number intended to increase an already sufficient reserve balance. That is significant, given the recent history of storm costs charged against the reserve and taking into consideration that the 2004 and 2005 storms factored into the study are storms that are not likely to occur and should not have been factored into the storm reserve determination purported to justify the predetermined $6.8 million result.

Q. **WHAT ARE YOUR CONCERNS WITH WHAT WAS NOT FACTORED INTO AND/OR IDENTIFIED IN THE STUDY OR COMPANY TESTIMONY?**

A. The Company has expended funds for storm hardening since the 2004 and 2005 storms occurred. The current filing includes a request for continuing storm hardening costs. There is no indication that the study factored the storm hardening that has been accomplished to date and that Gulf proposes to continue in the future.

The study includes a number of significant caveats. Page 4 states that the study provides no guaranty of any kind; that the limited nature of data causes a level of uncertainty; there is a "significant amount of uncertainty" in the hurricane severity and locations; and asset vulnerabilities, replacement costs and other computational parameters can cause estimated losses to be significantly different. Said differently, anything can happen and the results could be significantly different from what is reflected in the study.

Next, a major missing factor in testimony and in the study is an explanation as to why no alternative annual accruals were considered. As stated earlier, the study is not what results in the requested reserve accrual; it only shows what the estimated results may be on the Company's assumption that $6.8 million of charges would occur annually and the $3.5 million was continued as the annual accrual.

Finally, in Docket No. 060154-EI, Gulf hired ABS Consulting to perform a similar study in support of its request to increase its storm reserve. According to Mr. McMillan's testimony at pages 11-13, the study indicated that the expected annual losses to be charged against the reserve would be $6.4 million. The losses were based on the "expert forecasts of projected hurricane activity that conclude" the Company was "in a period of increased storm activity and higher probabilities of <u>hurricane landfall</u>" (emphasis added). As noted on Exhibit HWS-1, Schedule C-1 there has not been increased storm activity during the years 2007-2011 that generated average annual charges of $6.8 million as the experts had forecasted. And, based on the response to Citizens' Interrogatory No. 204, the last storm to make landfall in Gulf's service area was Hurricane Dennis in 2005. Had the Company taken into account the fact that the expectations from the last study differed significantly from the subsequent actual experience, the Company may have realized that the current study is biased.

Q. **WHAT ADJUSTMENT ARE YOU RECOMMENDING TO THE COMPANY'S RESERVE ACCRUAL AND RESERVE REFLECTED IN THE FILING?**

A. Based on the reserve current balance and what I expect the balance to be as of December 31, 2011, I believe justification exists to reduce the Company's to annual accrual to $600,000. This recommendation reduces O&M expense $6.2 million ($5,962,113 on a jurisdictional basis) as shown on Exhibit HWS-1, Schedule C-1, Page 1 of 2.

Q. **WOULD YOU EXPLAIN WHY YOUR ADJUSTMENT IS APPROPRIATE?**

A. The Company has established a reserve that is sufficient to cover major storms in the future. As discussed earlier, the calculated average cost of storms charged against the reserve excluding the unusual 2004 and 2005 storm costs is approximately $575,000. This recommendation that the annual accrual be reduced to $600,000 is based on the assumption that the annual charges will continue at the historical rate of $575,000 and after five years the reserve will be comparable to what it is expected to be as of December 31, 2011. That level of a reserve is sufficient to cover storm costs that are likely to occur based on recent history, and is a level that was previously determined by the Commission to be within a specific target range, as noted above. As shown on Exhibit HWS-1, Schedule C-1, Page 2 of 2, charging the most recent eight year average of $575,000 (excluding surcharge recovered storms) against the reserve while accruing $600,000 per year results in a December 31, 2016 reserve balance of $31,239,925.

Q. **ARE YOU AWARE OF ANY RECENT COMMISSION CASES WHICH DENIED OR REDUCED STORM DAMAGE RESERVE ACCRUAL?**

A. Yes. In two recent rate cases, the Commission eliminated the storm damage accrual requested by the utilities. In Florida Power & Light's (FPL's) last rate case, the Commission considered a request for annual storm damage accrual of $150,000,000 per year. [4] In denying FPL's request, the Commission noted the following:

> We note that there are provisions for the protection of utilities to allow them to seek recovery of prudently incurred storm costs that go beyond the reserve level. Because these mechanisms are in place to recover storm costs, we choose at this time, not to place this additional burden on the ratepayers.

Similarly, in Progress Energy Florida's (PEF's) last rate case, the Commission considered a request for annual storm damage accrual and denied it.[5] In both cases, the Commission noted that utilities have the option to petition the Commission for a storm surcharge to recover damages not covered by the storm damage reserve. While I am not asserting that the storm damage accrual for Gulf should be eliminated at this time, for the reasons state above, it should be reduced until such time that the storm damage reserve is fully funded.

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[4] See Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 080677-EI In re: Petition for increase in rates by Florida Power & Light Company, and Docket No. 090130-EI, In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; at pages 160-163.

[5] See Order No. PSC-10-0131-FOF-EI, issued March 15, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., Docket No. 090144-EI, In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., Docket No. 090145, In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.; at pages 68-71.

V. TREE TRIMMING EXPENSE

Q. DID YOU REVIEW THE COMPANY'S REQUEST FOR DISTRIBUTION TREE TRIMMING EXPENSE?

A. Yes. Company witness Scott Moore states in a simple paragraph at page 20 that the Company is requesting $4.918 million for distribution tree trimming in the projected test year 2012. The testimony suggests that this is the level of spending that is required to maintain the Vegetation Management Plan previously approved by the Commission in Docket No. 060198-EI[6]. Order No. PSC-06-0947-PAA-EI identified two levels of incremental spending for vegetation management for Gulf. One alternative was the implementation of a three year cycle that would increase the $3.2 million approved in Docket No. 010949-EI by $4.2 million to $7.4 million annually. Gulf's proposed plan was to address danger trees with an increased spending of $1.5 million, increasing the annual spending to $4.7 million. The filing in this current rate case reflects no detailed support or justification for including in rates either the level of tree trimming expense at the historic test year level of $4,910,578 or the projected test year level of $4,918,154.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S DISTRIBUTION TREE TRIMMING EXPENSE REQUEST?

A. Yes, a reduction of $386,834 is recommended on a jurisdictional basis, as shown on Exhibit HWS-1 Schedule C-2, for Distribution Vegetation Management. The

[6] See Order PSC-06-0947-PAA-EI, issued November 13, 2006, in Docket 060198-WI, In Re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.

adjustment factors in the Company's actual performance since the decision in Docket No. 060198-EI.

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S VEGETATION MANAGEMENT REQUEST?

A. The Company was allowed $3.2 million for vegetation management tree trimming in its last rate case, Docket No. 010949-EI[7]. In the Storm Hardening Docket No. 060198-EI, the Company's proposal to increase spending by $1.5 million was approved. The total approved spending beginning in 2007 would equate to $4.7 million. Since the approval of the incremental vegetation management costs, the Company has averaged $4,293,262 as shown on Exhibit HWS-1, Schedule C-2. Limiting maintenance in previous years, for whatever reason, is no justification for passing the catch up costs on to ratepayers. Therefore, the Company's sudden increase in spending when a rate case is being filed should not be the basis for the amount to be recovered from ratepayers prospectively. An adjustment is required to reflect the level of spending the Company is actually performing in its attempt to comply with the Storm Hardening Requirements approved by the Commission in Docket No. 060198-EI.

VI. POLE LINE INSPECTION/REPLACEMENT EXPENSE

Q. DID YOU REVIEW THE COMPANY'S REQUEST FOR POLE LINE INSPECTION/REPLACEMENT EXPENSE?

[7] See Order PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket 010949-EI, In Re: Request for rate increase by Gulf Power Company

A. The Company does not really address the increase of $409,963 in the projected test year 2012 expense. The filing reflects no real detail in support of increasing the level of expense above the historic test year level of $690,037. The 59.4% increase is not justified.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S POLE LINE INSPECTION/REPLACEMENT EXPENSE REQUEST?

A. Yes, a reduction of $371,701 is recommended on a jurisdictional basis, as shown on Exhibit HWS-1, Schedule C-3, for Pole Line Inspections. The adjustment is based on the historical actual spending in 2010.

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S POLE LINE INSPECTION/REPLACEMENT EXPENSE REQUEST?

A. The Company was allowed $734,000 for its pole line inspection program in its last rate case Docket No. 010949-EI. As shown on Exhibit HWS-1, Schedule C-3 the Company has failed to expend the allowed amount included in rates in six of the last seven years. It is not appropriate to collect funds from ratepayers for maintenance that is not being performed. The Company must show that it will spend as much or more than what has been allowed in rates to justify an increase to be included in future rates.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENT?

A. Even though the Company has averaged only $530,147 of spending in the past seven years, I am recommending that the 2010 spending of $690,037 be escalated to 2012 dollars, resulting in an expense of $728,299. Therefore the Company request for $1,100,000 as identified in Gulf's response to Citizens Interrogatory No. 212 should be reduced by $371,701 as shown on Exhibit HWS-1, Schedule C-3.

VII. PRODUCTION O&M EXPENSE

Q. WHAT DID YOU DETERMINE FROM YOUR REVIEW OF THE COMPANY'S PRODUCTION O&M EXPENSE REQUEST?

A. The Company is requesting in the projected test year $110,887,515, net of fuel, purchased power, ECRC, Plant Scherer and wholesale expenses. The December 31, 2010 test year reflected $92,889,451. That equates to an increase of 19.4% over two years. The request appears excessive when compared to the historical trend from 2001 to 2010.

Beginning on page 26, Company witness Raymond Grove provides an explanation for the increase in production O&M expense over the next five years. Mr. Grove attempts to justify the increase by first explaining the "robust budgeting process" and then by identifying five primary factors as to why production O&M is increasing. The first reason is that the age of Gulf's generation assets is increasing, requiring a greater level of maintenance. Next, Mr. Grove asserts that costs are increasing at a rate that is greater than inflation. Third, Mr. Grove states that Smith Unit 3 was relatively new during the years 2006-2010. The fourth primary factor identified was the addition of a new generating unit, Perdido, in October 2010. Finally, Mr. Grove states that Gulf worked hard in 2009 and 2010 time frame to lower O&M expenses so as not to burden customers with a rate request during what he has classified as "the worst economic downturn since the Great Depression."

Q. DO YOU HAVE CONCERNS WITH THE EXPLANATIONS PROVIDED BY THE COMPANY?

A. Yes. The first explanation that the units are getting older may have some merit, but not to the extent that it justifies the increase in costs that is being requested. It is true that the units are aging, but at the same time the Company is continuing to provide normal maintenance and, as evidenced by Mr. Grove's Schedule 5, there are significant capital expenditures being made that maintain each of the respective units' lives and/or even extend the units' lives.

The second explanation is that costs are increasing at a greater rate than inflation. This may be true with some costs, but not all. The inflation rate reflects changes of various costs, some that are higher than the average and some that are lower than the average. Companies will typically claim that the increase in expense is because costs are increasing at a rate greater than inflation. In the thirty plus years that I have been analyzing costs in rate proceedings, I have not seen a study submitted by a company that shows how the specific cost areas in question have exceeded the rate of inflation.

The third factor identified was Smith Unit 3 being relatively new in the 2006-2010 time period. Smith Unit 3 began operation in 2002. In fact the Commission in Docket No. 010949-EI specifically recognized the addition of Smith Unit 3 in justifying the increase in maintenance expense over the Company ~~over the~~ benchmark in their approval of the Company's Production O&M request. In my opinion, that factor, along with the historical spending that has occurred at

Smith as shown on Exhibit HWS-1, Schedule C-4, Page 2 of 2 suggests the Smith Unit costs are not a driving factor as Mr. Grove contends.

The Perdido unit going into service in October of 2010 was identified as the fourth primary factor. The unit is very small; therefore, the maintenance cost should not be a primary factor contributing to the 19.4% increase in expense.

Finally, the fifth factor was that costs were controlled in 2009 and 2010. That suggests that maintenance may have been deferred. The problem with that explanation is 2010 had the greatest level of Production O&M expense in the last 10 years. The Company has also stated in the response to Citizens' Interrogatory No. 224 that it has not deferred production maintenance. This appears to contradict the statement that Gulf kept O&M levels low to avoid a base rate increase, which statement in turn conflicts with the high expenditure seen in 2010. Gulf's rationales tend to cancel each other out. The only reasonable conclusion is that the amount sought for the test year is unsupported, and must be adjusted to a more reasonable level.

Q. WHY DO YOU BELIEVE THE COMPANY'S PRODUCTION O&M EXPENSE REQUEST IS EXCESSIVE?

A. The Company's $110,887,515 request has increased significantly when compared to the ten year average as shown on Exhibit HWS-1, Schedule C-4, Page 2 of 2. First the Baseline and Special Projects for each of the respective units is projected to increase from 14% to as high as 38% from 2010 to 2012. This must be considered to be significant, when historically unit costs have generally gone up and down between 2001 and 2010 with minimal fluctuations with one major exception. That exception is the significant spike in the 2010 corporate expense.

The historical outage costs by unit follow a similar pattern over the past ten years again, with one major exception. That exception, coincidentally, was the year 2002, during the time frame of the Company's last rate request.

Q. ARE THERE ANY OTHER CONCERNS THAT YOU HAVE IDENTIFIED WITH THE COMPANY'S INCREASE IN PRODUCTION O&M EXPENSE?

A. Yes. As shown on Exhibit HWS-1, Schedule C-4, page 1 of 2 the Baseline and Special Projects have been fairly level, averaging $74,553,191 over the years 2006-2010. The out years were a low of $70,025,586 in 2009, and a high of $82,018,531 in 2010. It would appear some shifting of maintenance occurred to offset in part an opposite shift of outage costs in the same years. Most significantly, the 2012 projected test year Baseline and Special Projects and Outage costs are 17.7% higher and 111.7% higher, respectively, than the five year average for 2006 through 2010.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PRODUCTION O&M EXPENSE REQUEST?

A. Yes. As shown on Exhibit HWS-1 Schedule C-4, Page 1 of 2 the Company's Production O&M Expense should be reduced $11,291,492 on a jurisdictional basis.

Q. COULD YOU EXPLAIN HOW YOU DETERMINED THE ADJUSTMENT TO THE PRODUCTION O&M EXPENSE REQUEST?

A First, I started with the five year average for the Production O&M expense. I escalated that by 5.5% for 2011, and then again by 5.5% for 2012. The 5.5% increase is the actual increase from 2010. I regard this as more than reasonable since, as shown on Exhibit HWS-1, Schedule C-4, Page 1 of 2, costs over the past five years have increased as well as decreased resulting in a simple average annual increase 1.18%. After escalating the average costs, I added the Company increase in labor, using the Company's 2012 labor of $30,828,000 and subtracting the five year average labor of $26,765,000. The average was calculated from Company Exhibit No.__(RWG-1), Schedule 7. I believe my use of the average is reasonable, since I utilized the average for a starting point in my calculation. The result is a recommended Production O&M expense of $99,212,245. The $99,212,245 is $11,675,270 less than the Company's requested $110,887,515. On a jurisdictional basis Production O&M expense is reduced $11,291,492.

Q. WHY SHOULD THE COMMISSION ACCEPT YOUR RECOMMENDATION TO REDUCE PRODUCTION O&M EXPENSE?

A. The Company's request for $110,887,715 is 19.4% higher than 2010. As I stated earlier, 2010 production O&M expense was unusually high in comparison to the years 2001 through 2009. Production O&M expense has fluctuated from year to year since 2001. I do not expect the significant spike projected by Gulf to continue, despite what the Company has reflected in its filing. The Company can control the costs incurred; to allow the spike in expense based on no more than the Company's claim, without evidence that the spending will continue, is akin to giving the Company a blank check. After ten years of essentially level spending, ratepayers need to be protected from a sudden spike that resulted from the

Company's "robust budget." Without some smoothing through the use of averaging, rates could be set artificially high and in future years shareholders would benefit from the over-collection.

Q. IS YOUR USE OF THE COMPANY LABOR DOLLARS AN INDICATION THAT YOU ARE ACCEPTING THE COMPANY LABOR REQUEST?

A. No. I have included the labor dollars solely to establish that my calculation is comparable to the Company's requested Production O&M Expense. Ms. Ramas is addressing the Company's labor request. Had I failed to recognize the increased labor figure used by Gulf, Ms. Ramas and I would have duplicated the labor adjustment.

VIII. DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. ARE YOU RECOMMENDING AN ADJUSTMENT FOR THE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A. Yes. According to the response to Citizens Production of Document Request No. 19, the Company has included at least $118,767 of expense in account 925 for Directors and Officers liability insurance (DOL). This expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. The question is whether this cost that the Company has elected to incur as a business expense is for the benefit of shareholders and/or ratepayers.

Q. HAVE YOU ADDRESSED THIS ISSUE IN PREVIOUS RATE CASE IN FLORIDA?

A. Yes, I have addressed it in three recent proceedings. In the Peoples Gas Company case and in the Tampa Electric case[8], the Commission allowed the cost to be included in customer's rates. In those cases, the Commission viewed the cost as a legitimate business expense. More recently in the Progress Energy Florida case (Docket No. 090079-EI[9]), the Commission observed that other jurisdictions make an adjustment for DOL insurance and that it has disallowed DOL insurance in wastewater cases in the past. The Commission allowed PEF to place one half the cost of DOL insurance in test year expenses.

Q. ARE THE MOST RECENT PEF DECISION AND THE PAST WASTEWATER DECISIONS WHY YOU ARE RECOMMENDING AN ADJUSTMENT FOR THE COST ASSOCIATED WITH DIRECTORS AND OFFICERS LIABILITY INSURANCE IN THIS CASE?

A. Only in part. The Florida Commission has in the past disallowed DOL insurance costs. But even if the costs had not been disallowed, I would still recommend a disallowance, because the cost associated with DOL insurance benefits shareholders first and foremost. In ratemaking, the cost should follow the benefit. The benefit of this insurance clearly inures primarily to shareholders. Ratepayers are not the parties who initiate litigation that is associated with

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[8] See Order No. PSC-09-0411-FOF-GU, page 38, issued June 9, 2009, in Docket No. O80318-GU, In re: Petition for rate increase by Peoples Gas System; and Order No. PSC-09-0283-FOF-EI, issued April 30, 2009 in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

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

decisions made by the officers and directors of the Company. Generally, the one initiating any suit is a shareholder. However, I am aware that, in the PEF docket, the Commission determined that the customer and the shareholder both benefit, and decided that there should be a sharing of the cost associated with that benefit.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE INCLUDED IN THE COMPANY'S REQUEST?

A. I am recommending a disallowance of $59,384 or 50% of the identified 2012 projected test year expense ($58,196 jurisdictional). This is consistent with the decision in Docket No. 090079-EI.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. SAYLER:

Q. And it is my understanding that you have also prepared two exhibits to your direct testimony, and those are exhibits identified in the Comprehensive Exhibit List as Number 37 and 38; is that correct?

A. Yes.

Q. All right. And have you prepared a summary of your testimony?

A. I have.

Q. All right. Would you please summarize your testimony for our Commission?

A. Yes.

Q. For this Commission.

A. Good morning, Commissioners and interested parties. My prefiled testimony addresses the company's request for including $26.7 million in plant held for future use to build a nuclear plant on approximately 4,000 acres in North Escambia County; the company's unsupported request to increase storm reserve accrual from 3 1/2 million to 6.8 million; the company's excessive request for tree trimming, pole inspections, production O&M maintenance; and finally, the appropriateness of sharing the cost of directors' and officers' liability insurance.

The company's request to include the North

Escambia County property in plant held for future use is not appropriate. The company has not filed and/or received a determination of need on that property. The company is asking for inclusion in rate base only to provide them an option in the distant future for determining a nuclear need. There are at least two other plant sites available to the company that are already in plant held for future use to provide future generation if need arises.

The proposed cost to be included in rate base is partially estimated. As indicated on page 6 of my testimony, the company has indicated in response to Citizen Interrogatory Number 24 that it has no definite plans to build any type of generation in the near future. And I emphasize "near future," because as indicated on page 11 of my testimony, the Commission determined that for plant to be included in plant held for future use, the cost must be prudent, and it appears it will be used for utility purposes in the reasonably near future. The company has not shown a definite need, and it has admitted that it has no need in the near future, so the cost should not be allowed in plant held for future use, nor should it be allowed to continue to earn a return on that.

The company's request to increase the storm reserve accrual is not supported based upon actual historic storm costs that would typically be charged against the reserve. Instead, the request is purportedly based on thousands of hypothetical storms that far exceed the number of actual storms that have occurred over the past years and focus on damages that occurred in 2004 and 2005 that are not typical storms that are charged to the reserve.

On the other hand, the company-requested increase that is purportedly supported by this questionable study totally ignores any significant level of storm hardening that has occurred since 2007.

The study also ignores the Commission's decision in Progress and FP&L that notes that there is a mechanism for recovery of extreme storms. The current storm reserve level is sufficient, and it is not designed to address the impact of severe storms like the 2004-2005 storms.

The production O&M and the tree trimming and the pole inspection costs are costs that are historically lower than what the company is requesting in this filing. That historical reflection has to be considered when determining what is reasonable and necessary. I recognize in my testimony that the company has a budget process, but the fact remains that the history reflects what the company does for spending.

With respect to the directors' and officers' liability insurance, the company's shareholders pick the directors. The directors essentially pick the officers. So what that insurance does is, it provides protection for the shareholders from their decision to pick the officers and directors. Therefore, that cost, at a minimum, should be shared between shareholders and ratepayers to reflect the benefit that accrues to both parties.

Thank you.

MR. SAYLER: Mr. Chairman, we tender our witness for cross.

CHAIRMAN GRAHAM: Intervenors?

MR. WRIGHT: Mr. Chairman, I do have a few questions for Mr. Schultz regarding the storm accrual. We have taken a position that no accrual should be necessary for Gulf Power. He has advocated $600,000 a year, and I want to probe that with him, please.

CHAIRMAN GRAHAM: Okay.

MR. WRIGHT: Thank you.

CROSS-EXAMINATION

BY MAJOR THOMPSON:

Q. Good morning, Mr. Schultz.

A. Good morning.

Q. Welcome back to Tallahassee.

A. Thank you.

Q. In your testimony, you advocate an annual storm accrual for Gulf Power on the order of $600,000 a year; is that correct?

A. That's correct.

Q. Do you recognize that Gulf's storm reserve bears interest?

A. Yes.

Q. Do you agree that if the -- I understand it's at the short-term commercial paper rate. Is that your understanding, or do you know better than I?

A. That's what I've heard. I haven't looked into it past the fact that I know it's --

Q. Well, let me ask you this. If the short-term rate that was accruing to the fund was 2 percent a year, that would accrue something in the range of 600 to $620,000 a year to the fund absent charges against it; correct?

A. I'll accept your math on that, yes.

Q. Even if there were charges against the fund of 600,000 a year -- let me back up. Your 600,000 a year is based on unextraordinary charges to the fund, i.e., absent extraordinary storms of around $575,000 a year;

right?

A. That is correct.

Q. Okay. Here's my question for you: If the company were to experience ordinary charges of about $600,000 a year, even if the fund were not earning interest, how long would the fund last before it would be depleted?

A. If the fund was incurring $600,000 a year --

Q. I'm asking you to assume for this particular question that it's not even accruing interest.

A. That it's not accruing interest.

Q. Yes. At $600,000 a year, how long would $31 million last?

A. Is it accruing additional amounts to the reserve?

Q. Without any accrual, so the answer to your question is no.

A. Okay. In that case, you would be looking at about 50 years.

Q. Okay. And if it were accruing interest at $600,000 a year, wouldn't it be true that the reserve would remain at its 30, $31 million level in perpetuity until there were some extraordinary charges?

A. Yes.

Q. Okay. Do you know whether Florida Power &

Light company currently has an accrual to its storm reserve built into its base rates?

A. No, they do not.

Q. And do you know how that came to pass?

A. Yes.

Q. Can you tell us?

A. Well, that decision came out shortly after the Progress Energy hearing, where they also were not allowed any further accrual. In the Progress Energy hearing, I said the company shouldn't get an accrual anymore.

Q. In light of the numeric facts that we discussed earlier, interest that might come close to the annual charges, the fact that even without interest it might last 50 years, and in light of the prior PSC's decisions to discontinue accruals for FPL and Progress Energy Florida, would you agree that a continuing accrual to Gulf's storm reserve is not necessary, at least not at this time, for Gulf to provide safe and reliable service at the lowest possible cost?

MR. GUYTON: Objection. This is clearly friendly cross, and he's to the point now where he's adopting the witness as his own.

MR. WRIGHT: It's not friendly cross. He's advocating $600,000. I want him to go to zero, Mr. Chairman.

MR. GUYTON: A position of convenience that was changed a day or two ago to facilitate this facade.

MR. WRIGHT: Excuse me, Mr. Chairman. If Mr. Guyton is accusing me of changing my position, he is flat wrong. That's our position in our prehearing statement.

MR. GUYTON: I'll withdraw the objection.

CHAIRMAN GRAHAM: Okay.

MR. WRIGHT: May he answer the question?

CHAIRMAN GRAHAM: Yes.

BY MR. WRIGHT:

Q. Does Gulf need a continuing storm reserve accrual to continue providing safe and reliable service at the lowest possible cost?

A. Say that again. I'm missing something, I think.

Q. Does Gulf Power Company need a continuing storm reserve accrual greater than zero to provide safe and reliable service to its customers at the lowest possible cost?

A. Actually, I would have to say I believe they did. That's why I recommended the $600,000.

MR. WRIGHT: Okay. Thank you.

CHAIRMAN GRAHAM: Staff?

MS. KLANCKE: Staff has no questions of this witness.

CHAIRMAN GRAHAM: Gulf, do you want to address the storm accrual?

MR. GUYTON: I have no questions.

CHAIRMAN GRAHAM: Commissioner Brown?

COMMISSIONER BROWN: Thank you. Now I get to ask my question. Hello. How are you?

THE WITNESS: Fine, thank you.

COMMISSIONER BROWN: Good. As a follow-up, with regard to the storm reserve accrual, this area is obviously prone to severe weather, and I'm still trying to understand why you're recommending a reduction to $600,000. I read your direct testimony, and I still just want a better understanding.

THE WITNESS: Well, the purpose of the reserve -- and this has been basically made clear, I think, in the Progress Energy decision and the Florida Power & Light decision. The reserve is to address certain storms, not every storm. And so the severity of the storm has to be taken into consideration when you're trying to determine the level that should be in the reserve.

The storms that happened in 2004 and 2005 were significant. I know the company witness Erickson has indicated that she didn't consider them severe, but to me, $134 million, that's a significant storm. In fact, that's a level of storm that, in my opinion, and I believe in the Commission's opinion in the past, is not a storm that should be considered as a reserve requirement storm in determining that reserve requirement. And therefore, you have to exclude those storms when you're determining what kind of storms are generally charged in a typical nature to the reserve.

And that's what I did in my analysis. I excluded the 2004 and 2005 storms that were being recovered through a surcharge mechanism. And the average storm reserve in that -- for the storms over that ten-year period then was 575,000. Assuming that that 575,000 is going to continue on a going-forward basis, that's where I came up with the 600,000.

Had there than some other factor, like the reserve level would have been higher than it is currently, I might have gone more with what counsel's last questions went to and said they should be a zero. But since the reserve is kind of a target point right now of what the Commission had in the past, I think it's something that you have to still consider.

There will be storms. And I think the indication that there was a charge in 2011 of approximately $600,000, that that reflects what the annual impact could be total reserve.

So I didn't know ahead of time that that was going to be $600,000. You know, that just kind of came up coincidentally at that level.

COMMISSIONER BROWN: Okay. I see how you got there. Thank you.

And just switching gears, last question. I can certainly appreciate your analysis and recommendation of the DOL insurance and your recommendation. I have a question for you regarding -- are you familiar with other jurisdictions and how they handle DOL insurance?

THE WITNESS: Yes, I am.

COMMISSIONER BROWN: Are you familiar with how they allocate or disallow portions of the DOL insurance? If so, could you please provide the Commission with that information?

THE WITNESS: In Connecticut, DOL insurance is split on a case-by-case basis. They'll also -- they'll look at the level of coverage that's included and maybe take the top layer off just for the fact of the coverage. And in fact, that was also done in New York in a Consolidated Edison case that I was in. They took off some off the top, and then they split it 50-50 between shareholders and ratepayers.

So generally speaking, after people saw what happens in things like the Enron occurrence, the light bulb came on that says, yeah, shareholders are the ones who come after the corporation for recovery. And therefore, you know, they're the ones that should bear some of the cost of that, and that's where I've seen the sharing take place.

COMMISSIONER BROWN: Thank you.

CHAIRMAN GRAHAM: Mr. Schultz, I have a question too. I'm not sure if I heard you correctly or not in your summary. You said that Gulf has got two other sites available for future power generation?

THE WITNESS: Yes.

CHAIRMAN GRAHAM: Are these sites of the size that can handle a 1200-megawatt nuclear plant?

THE WITNESS: No, they're not designed for a nuclear megawatt -- a 1200 nuclear megawatt plant. The Caryville site was, I think, approved for two 500-megawatt coal units, and then there's the Mossy Head site can be used, which is smaller yet.

But these sites have also been in plant held for future use for years. I mean, Caryville has been in plant held for future use for 29 years, and the company hasn't found a need for that. So to add another one, that's almost like adding insult to injury to ratepayers, like let's just keep piling it on. There has to be a limit as to how much plant held for future use can be accumulated, I believe.

CHAIRMAN GRAHAM: But your testimony is that neither one of those two sites will handle a nuclear plant?

THE WITNESS: That's my understanding from the company and my understanding from reading what I have read about them. They're not sufficient to handle a nuclear plan.

CHAIRMAN GRAHAM: Okay. Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I would like to follow up briefly on your responses to Mr. Wright and Commissioner Brown regarding the storm reserve recommendation annual accrual that you've made.

Did I understand correctly that in your analysis, you are discounting the storm events in '04 and '05 when basing your accrual amount?

THE WITNESS: Well, I took them out, yes. I took the costs associated with them out of the costs incurred by the company over the last 10 years.

COMMISSIONER EDGAR: Why?

THE WITNESS: Because again, those were extreme storms. The reserve isn't intended to cover the cost of extreme storms, and that was made evident by the Commission in Progress Energy's decision and the Florida Power & Light decision.

COMMISSIONER EDGAR: Are you aware that the vote on that issue was not unanimous?

THE WITNESS: I think that was the case, yes.

COMMISSIONER EDGAR: Do you know what the vote was?

THE WITNESS: I don't have that clear a recollection of whether it was or not. I thought there may have been a dissenting vote on that, but I --

COMMISSIONER EDGAR: Would you accept that it was 3 to 2?

THE WITNESS: I would accept that.

COMMISSIONER EDGAR: The order that the Commission issued in '93 authorizing a self-insurance mechanism for storm damage, my understanding of that order -- and I did not participate in that. That predates even me. But my understanding of that order is that it established a framework for the recovery of storm damage costs that involved three facets, one of which is an annual storm accrual, one of which is a storm reserve adequate to accommodate most, but not all storm events, and the provision for utilities to seek recovery of costs that go beyond the storm reserve.

In an answer that you gave just a -- I think to Commissioner Brown, although it may have been to Mr. Wright, I thought I understood you to say that the decision in the Progress and FPL rate cases was based upon there being the ability for a company to seek recovery through a surcharge, which to me seemed to put, of those three components, a great deal of weight on one, but not the three. Did I understand that correctly?

THE WITNESS: You understood that correctly. I factored in what was decided in previous cases, because I looked at those decisions.

COMMISSIONER EDGAR: All previous cases or just two?

THE WITNESS: I looked at the old decisions. Specifically, I looked at what was addressed in some of the storm dockets too. So I've looked at those.

And the thing is that, again, as you indicated, in the one, it wasn't to address all storms. That was, I think, your second point that you --

COMMISSIONER EDGAR: Yes.

THE WITNESS: -- identified. And you have to take into consideration when you're looking at the storms that are going to be hitting that reserve, you have to look at how often a storm of the magnitude of Ivan is going to hit that reserve. I mean, that was significant.

In my recommendation in those two cases -- well, in Progress, not the two cases, but in Progress, I looked at the fact that the storms that were extraordinary in nature, extreme, I took those out of my analysis also because of the fact that those were -- and I'm going to put it in my terms -- you know, rare occurrences, maybe the one in a hundred year storm. In fact, in Progress, they didn't even indicate that that's what it was. In fact -- yes, the company even referred to it, I believe, that it was that rare.

And I believe that in the case of Gulf Power, you know, the fact that a storm of that magnitude -- and my addressing the magnitude is not only to the veracity of the storm, but it's also to the -- it's to the cost. It's what damage it did. That's what you've got to really look at. I mean, the storm may not seem as severe. It could be a Category 2 storm, but it may impact a significant amount of dollar damage, and the dollar damage is what we've got to be looking at. You can't focus only on the fact that it was a Category 3 storm or a Category 2 storm. You have to look at how much damage was there.

And again, the Ivan storm was significant dollar-wise. And to factor that and assume that's going to occur at a level that you're going to have to factor that into your annual damage accrual, I think that's taking it to an extreme. That's above and beyond who the reserve was intended for.

COMMISSIONER EDGAR: My understanding of your answers, which I appreciate, is that you put a great deal of weight on the decisions in the recent FPL and Progress rate cases. Did you also consider the decisions in the TECO rate case of a few years ago?

THE WITNESS: Yes, I did. In fact, I participated in those cases also. And again, I don't want you to walk away with the thought that those were my primary focuses. I mean, my testimony also addresses the fact that the storm hardening wasn't addressed, which I think is significant.

I also took issue with the positioning of the storms, the fact that the company can't identify like the ZIP codes, because the specific area where those storms impact have an impact on the level of damage that's going to occur. And to assume that that historic -- just ignoring history of where that damage has occurred in the past and assuming that all these synthetic storms could just hit each and every area assumes things that haven't occurred, and there's no indication that they would occur.

I hope you're following what I'm saying.

COMMISSIONER EDGAR: I think so. And I think I have just one additional question on this point.

I think I heard you say just a moment ago that Ivan was perhaps a one in a hundred year storm event. Are you aware of prior to Ivan when the last storm event that was considered significant hit the Gulf service area?

THE WITNESS: Not the last significant storm, you know, what I consider significant.

COMMISSIONER EDGAR: Would you consider Opal in '95 significant?

THE WITNESS: I don't -- I understand that the damage was large at that time. I don't know the amount of damage that it did off the top of my head. '95?

COMMISSIONER EDGAR: I believe it was September of '95.

THE WITNESS: Okay. Yeah, because after Opal or after 1995, I mean, there wasn't a lot of damage between the years of 1996 and 2000, I know that, from storms.

COMMISSIONER EDGAR: Which is significantly less than a hundred years.

THE WITNESS: Yes, but I don't know the extent of the damage from Opal, that's all.

COMMISSIONER EDGAR: All right. Thank you.

CHAIRMAN GRAHAM: Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Mr. Chairman. I'm going to address the same issue from a different perspective.

Ms. Erickson on yesterday talked about the difference between pursuing the accrual track versus the surcharge track. And I'm going to ask you the question whether you think one impacts the other, and if so, what are your thoughts on that?

THE WITNESS: I think that -- let me first address what was said by Ms. Erickson on that. You know, she talked about her informal study. And to me, first of all, ratemaking is not something that everybody understands. In fact, I think it's a small portion of people who understand what ratemaking is all about. And if you go and ask somebody a question that says, "Would you rather have your rates increase 27 cents a year or 10 times that should a storm hit," the first thing anybody is going to say in response to a question like that is, "I only want it to go up 27 cents a year, not 10 times."

The whole story has to be there. You can't just come up with a statement like that and give the impression that, "Wow, you're going to be hit with this $2.70 a month charge who knows for how long." So it's going to be -- it was kind of a misleading question, I would think, in my opinion, especially to an uninformed public of what the impact could be.

And so I think that there is a difference, and significantly, because you're asking somebody to pay for the storm today, under the company's idea, that may not be a customer tomorrow. So why should they pay for that storm ahead of time?

Do you as a Commissioner, or as an individual, let's say, go out and buy a car, and start paying for it before you get it? No. You don't pay for it ahead of time. So why should you have to have customers pay for something in advance? That's not a fair treatment of the ratepayer.

And to suggest that, "Well, if you don't pay for it in advance, you're going to really get hit, you know, down the line," that's almost like a scare tactic to me, I mean, to be frank. And it's like -- they did go over this yesterday. When plant goes into service, you begin to pay for it, and you start to pay for it as long as you're a customer. And if a storm occurs when you're the customer, then that customer should be paying for that storm. If it needs be, then a surcharge is implemented.

And that's the key thing too, if it needs be. I mean, if you look at the history of storms, even the level of storms, I mean, they took into the study thousands of storms, synthetic storms. But in response to a data request, it indicated in the last hundred years there's been 67 storms that made landfall in Florida, just 67. So by factoring in thousands as they did in the synthetic, you're really putting more emphasis on the worst case scenario.

And you've also got to, again, like I said, you know, you take a look at what's in the area hit. I mean, when it comes to Florida, it's my understanding from what I've seen that the area hit is Miami most predominantly, not Pensacola.

So, yeah, the storm -- the 27-cent storm --

COMMISSIONER BRISÉ: Thank you.

THE WITNESS: -- charge may sound nice, but I don't agree with her analogy on that.

COMMISSIONER BRISÉ: Thank you. All right. That was a pretty long answer for a very succinct answer that you gave at the very end there.

Moving on to another issue with respect to the Escambia site, I think Commissioner Graham started to go down a path in terms of if that particular site was suitable for a nuclear plant. And so based upon what you said in the testimony and what you just said recently with respect to the question about the hurricane stuff, you would want to see those costs recovered through, say, a nuclear cost recovery clause at some point rather than for it to be recovered in base rates now?

THE WITNESS: Well, I guess the first thing I would like to see is, are they going to build a nuclear plant. I mean, it's an option, is what the company is saying. They don't know that they're going to build a nuclear plant.

They're part of Southern Company. You've got to remember that Southern Company has already got two major construction projects in place. They've got Vogtle going, and they're building a big coal gasification plant in Mississippi. So there's a lot of generation going up there, and if they were serious about building a nuclear plant, you would think there would be more on the board, in fact, as to the possibility of it. I saw an article on the guy in charge of Southern Company's building of Plant Vogtle, and there wasn't a mention of any other nuclear sites.

So that's the question: Is there a really possibility of that occurring? And in my opinion, I don't think there is, because we're looking at a company that doesn't have an exclusive need for it, so therefore, they shouldn't have the plant held for future use exclusively charged to their ratepayers.

COMMISSIONER BRISÉ: Okay. Thank you very much.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you. I have a quick question. If you can turn to Schedule C-1 of HWS-1.

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: In Gulf's request, they're requesting that, I believe, 3.3 million annually be recovered for storm accrual; correct?

THE WITNESS: No. They're requesting 6.8 million.

COMMISSIONER BALBIS: I'm sorry.

Okay. So 6.8 million. And looking at this Schedule C-1, in the beginning balance column, I assume that the $49 million followed by the $43 million, the reduction -- I'm sorry. Let me go to the storm charges. Line number 4, that

$93 million, I assume those are the severe storms in '04.

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: And then going back to the column on beginning balance, you see the balance go to a negative 49 million, negative 43 million, and then it gets to a positive balance once insurance or surcharge is collected; is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: So the accrual, the annual accrual of 6.5 million, 3.5 million, as it goes down the line on different line items, that really doesn't have as significant of an impact as the insurance or surcharge collected in adding to the balance of the fund; correct?

THE WITNESS: Say that again.

COMMISSIONER BALBIS: Okay. If you go down the accrual column, I assume that the accrual is the amount that Gulf is recovering from ratepayers on an annual basis. Is that correct?

THE WITNESS: For the most part, not totally.

COMMISSIONER BALBIS: Let me go round this a different way. I apologize for not being clear.

The severe storms resulted in a $93.4 million charge to that account; correct?

THE WITNESS: That's correct.

COMMISSIONER BALBIS: So the $6.8 million annual accrual, if a severe storm occurs of the same magnitude as '04, that recovery amount cannot come close to paying for the costs associated with that storm; correct?

THE WITNESS: That's correct. But you've got to take in mind what has happened in the past.

COMMISSIONER BALBIS: No, that's -- just work with me here on this.

THE WITNESS: Okay.

COMMISSIONER BALBIS: So if this Commission approves a $6.8 million annual accrual, and looking at the balance currently, would Gulf Power still have -- and a storm hits of the same magnitude as '04 and '05, would Gulf Power still have to implement a surcharge to recover the costs, for recovery?

THE WITNESS: I think they would, and they probably would want to, because they say you've done it in the past, and therefore, let's do this so we can maintain some kind of level of positive value in our storm accrual to address the normal storms.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Redirect?

MR. SAYLER: No, Mr. Chairman.

CHAIRMAN GRAHAM: Exhibits.

MR. SAYLER: Mr. Chairman, we have Exhibits 37, 38, and 206 to move into the record for Witness Schultz.

CHAIRMAN GRAHAM: Exhibits 37 and 38 on page 10.

MR. SAYLER: Yes, sir.

CHAIRMAN GRAHAM: And 206.

MR. SAYLER: Yes, sir.

CHAIRMAN GRAHAM: Enter those into the record.

(Exhibit Numbers 37, 38, and 206 were admitted into the record.)

MR. SAYLER: And may our witness be excused?

CHAIRMAN GRAHAM: If there's no objections, we can excuse the witness.

MR. SAYLER: All right. Thank you. Thank you, Mr. Schultz.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Next witness.

MR. SAYLER: Mr. Chairman, the Office of Public Counsel would like to call Ms. Kimberly Dismukes to the stand. And she also has an errata sheet for her testimony, and I would like to identify an exhibit number for it.

CHAIRMAN GRAHAM: I have that. We can call that 207.

(Exhibit Number 207 was marked for identification.)

MR. SAYLER: Ms. Dismukes, have you been previously sworn in this proceeding?

THE WITNESS: No, I have not.

MR. SAYLER: All right.

(Witness sworn.)

Thereupon,

KIMBERLY H. DISMUKES

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. SAYLER:

Q. Please state your name and business address for the record.

A. Kimberly Dismukes, 5800 -- I've forgotten my address -- Perkins Place Drive, Suite 5F, Baton Rouge, Louisiana, 70808.

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

A. Acadian Consulting Group. My title is senior research consultant.

Q. And on behalf of the Office of Public Counsel, did you prepare and submit direct testimony in this proceeding on October 14, 2011?

A. Yes, I did.

Q. And do you currently have that testimony with you?

A. Yes, I do.

Q. And do you have any corrections or revisions to make to your prefiled testimony?

A. Other than the errata?

Q. Other than the errata.

A. No, I do not.

MR. SAYLER: All right. Mr. Chairman, will this exhibit suffice for the errata, or would you would you like her to go through it?

CHAIRMAN GRAHAM: No.

MR. SAYLER: Okay.

BY MR. SAYLER:

Q. As modified and corrected, do you adopt the prefiled testimony as your testimony today?

A. Yes, I do.

Q. And according to the Staff's Comprehensive Exhibit List, you have 13 exhibits. Those are identified on page 11 as Exhibits 39 through 51; is that correct?

A. Yes.

Q. And have you prepared a summary of your testimony?

A. Yes, I have.

MR. SAYLER: My apologies. Mr. Chairman, I would ask that her prefiled testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Ms. Dismukes' testimony into the record as though read.

MR. SAYLER: Thank you.

REDACTED VERSION

DIRECT TESTIMONY

OF

Kimberly H. Dismukes

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 110138-EI

Q. WHAT IS YOUR NAME AND ADDRESS?

A. Kimberly H. Dismukes, 5800 One Perkins Place Drive, Suite 5F, Baton Rouge, Louisiana 70808.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a partner in the firm of Acadian Consulting Group, LLC which specializes in the field of public utility regulation. I have been retained by the Office of the Public Counsel ("OPC") on behalf of the Citizens of the State of Florida to analyze the application of Gulf Power Company ("Gulf Power" or "Company") to increase its rates and charges.

REDACTED VERSION

Q. DO YOU HAVE A SCHEDULE THAT DESCRIBES YOUR QUALIFICATIONS IN REGULATION?

A. Yes. Schedule KHD-1, was prepared for this purpose.

Q. DO YOU HAVE SCHEDULES IN SUPPORT OF YOUR TESTIMONY?

A. Yes. Schedules KHD-2 through KHD-13 were prepared for this purpose.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into five sections. In the first section, I give a brief background of the instant proceeding. In the second section, I discuss the importance of monitoring affiliate transactions. In the third section, I address the relationships between Gulf Power and its affiliates. In the fourth section, I address the allocation of costs from Southern Company Services ("SCS"), the service company that provides service to the Company as well as its sister companies. In section five, I address other affiliate transaction adjustments to test year expenses and investments.

I. Background

Q. WOULD YOU PLEASE PROVIDE SOME BACKGROUND TO THIS PROCEEDING?

A. Yes. Gulf Power is a wholly-owned subsidiary of The Southern Company ("Southern Company"). The Company is headquartered in Pensacola, Florida, and has provided electric utility service since 1926. Currently, Gulf Power serves more than 431,000 retail

REDACTED VERSION

customers across eight counties in Northwest Florida through the generation, transmission, distribution, and sale of electric energy and energy-related services.

Q. **HOW LONG HAS IT BEEN SINCE GULF POWER'S LAST RATE CASE?**

A. It has been slightly more than nine years since the Company's last rate case. The base rate portions of the Company's current rates and charges were established by Order No. PSC-02-0787-FOF-El, issued June 10, 2002, in Docket No. 010949-EI, based on a projected test year and 13-month average rate base ending May 31, 2003.

<u>II. Affiliate Transactions: Importance of Review</u>

Q. **WHY IS IT IMPORTANT TO CLOSELY EXAMINE AFFILIATE TRANSACTIONS?**

A. In a situation involving the provision of services between affiliated companies, the associated transactions and costs do not represent arms-length dealings. Cost allocation techniques and methods of charging affiliates should be reviewed and analyzed frequently to ensure that the company's regulated operations are not subsidizing the nonregulated operations. Because of the relationship between Gulf Power and the affiliates which contribute to expenses included on the books of the Company, the arms-length bargaining of a normal competitive environment is not present in their transactions. Although each of the affiliated companies is supposedly separate, relationships between Gulf Power and its affiliates are still close – they all belong to one corporate family, Southern Company. In the absence of regulation, there is no assurance that affiliate transactions and allocations will not translate into unnecessarily high charges for Gulf Power's customers. Even when the methodologies for cost allocation and pricing have been explicitly stated, close scrutiny of affiliate relationships is still warranted. Regardless of whether or not Southern Company, the holding company, explicitly establishes a methodology for the allocation and distribution of affiliate costs, there is an incentive to allocate or shift costs to regulated companies so that the nonregulated companies can reap the benefits with higher profits for shareholders.

Q. DOES THE COMMISSION HAVE ANY GUIDELINES WHICH CONTROL THE PRICING ARRANGEMENTS BETWEEN UTILITIES AND THEIR AFFILIATES?

A. Yes. The Commission's Rules set forth the criteria to be followed by electric utilities when transacting with affiliates. Rule 25-6.1351, Florida Administrative Code (F.A.C.), details the Commission's policy. It excludes affiliate transactions related to the purchase of fuel and related transportation services that are subject to the Commission's review in cost recovery proceedings. Subsection (3) of the rule provides specific details about the pricing between affiliates and the regulated utility.[1] It states that purchases from the utility by the affiliate must be at the higher of fully allocated cost or market price.[2] The rule further states that purchases from the affiliate must be at the lower of fully allocated cost or market price.[3] Finally, the rule states that assets transferred from the affiliate to the utility must be transferred at the lower of cost or market, and assets transferred from the utility to the affiliate must be transferred at the higher of cost or market.[4]

[1] Rule 25-6.1351 (3), F.A.C.
[2] Rule 25-6.1351 (3)(b), F.A.C.
[3] Rule 25-6.1351 (3)(c), F.A.C.
[4] Rule 25-6.1351 (3)(d), F.A.C.

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Q. HAS THE COMMISSION ADDRESSED AFFILIATE TRANSACTIONS IN ANY ORDERS?

A. Yes. The Commission has expressed its opinion on affiliate transactions and the precedent that should be followed when examining affiliate transactions. Although a transaction between related parties is not *per se* unreasonable, by their very nature transactions between related parties require closer scrutiny. It is always the utility's burden to prove that its costs are reasonable.[5] This burden is even greater when the transaction is between related parties. In GTE Florida, Inc. v. Deason, the Court established that the standard to use in evaluating affiliate transactions is whether those transactions exceed the going market rate or are otherwise inherently unfair.[6]

Q. DOES NARUC HAVE GUIDELINES RELATING TO COST ALLOCATIONS AND AFFILIATE TRANSACTIONS?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") adopted the "NARUC Guidelines for Cost Allocations and Affiliate Transactions" ("Guidelines") addressing electric and gas operations on July 12, 1999. In a letter to the Securities Exchange Commission, NARUC explained that these Guidelines were intended to provide guidance to jurisdictional regulatory authorities, regulated utilities, and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates.[7]

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[5] Florida Power Corp. v. Cresse, 413 So. 2d 1187, 1191 (Fla. 1982).
[6] GTE Florida, Inc. v. Deason, 642 So. 2d 545, 548 (Fla. 1994).
[7] National Association of Regulatory Utility Commissioners ("NARUC") comment letter regarding the Securities and Exchange Commission's ("SEC") notice of proposed rulemaking on Foreign Utility Companies published at 66 Fed. Reg. 9,247 (February 7, 2001). April 9, 2001, p. 3. (hereinafter "NARUC SEC letter") available at http://www.sec.gov/rules/proposed/s70501/ramsay1.htm.

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The prevailing premise of NARUC's Guidelines is that allocation methods should not result in subsidization of nonregulated services or products by regulated entities. When it comes to allocating costs, the Guidelines state that all direct and allocated costs between regulated and nonregulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. NARUC's Guidelines also state the primary cost driver of common costs, or a relevant proxy in absence thereof, should be identified and used to allocate costs. In addition indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.[8]

NARUC's Guidelines further discuss pricing affiliate transactions, which are based on two assumptions:

> First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. . . .[9]

The Guidelines state that products and services provided by the regulated utility to nonregulated affiliates should be priced at the higher of cost or market while products and services provided by the nonregulated affiliate to the regulated utility should be priced at the lower of cost or market. For all affiliate transactions, an audit trail should exist, and state regulators should have complete access to all affiliate records necessary to ensure

[8]NARUC SEC letter at 3, 5.
[9] NARUC SEC letter at 6.

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that cost allocations and affiliate transactions are conducted in accordance with the Guidelines.[10]

Q. **WOULD YOU PLEASE COMMENT ON THE COMPANY'S STATEMENT IN SCS' "COST ACCOUNTABILITY AND COST CONTROL MANUAL" THAT THE FACTORS USED TO ALLOCATE COSTS BETWEEN GULF POWER AND ITS AFFILIATES WERE APPROVED BY THE SECURITIES AND EXCHANGE COMMISSION ("SEC")?**

A. Yes. Under the Public Utility Holding Company Act of 1935, the SEC had authority to approve the allocation of costs between affiliated utility companies. However, this act was repealed with the enactment of the Energy Policy Act of 2005, and the authority now rests with the Federal Energy Regulatory Commission ("FERC") and state regulators.[11]

<u>III. Gulf Power Affiliates</u>

Q. **WOULD YOU PLEASE DESCRIBE GULF POWER'S AFFILIATES?**

A. Southern Company, the parent company of Gulf Power, is a publicly traded holding company with both regulated and nonregulated subsidiaries operating in four states. Schedule KHD-2 of my exhibit contains an organizational chart of Southern Company and its affiliates. Its regulated utilities serve over four million customers and include Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. In addition to its regulated subsidiaries, Southern Company owns several nonregulated subsidiaries:

[10] NARUC SEC letter at 6.

[11] Energy Policy Act of 2005, Sec. 1263 and 1267.

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- Southern Power Company ("Southern Power") – constructs, acquires, owns, and manages generation assets and sells electricity in the wholesale market;
- SouthernLINC Wireless – provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast;
- Southern Nuclear – operates and provides services to Alabama Power's and Georgia Power's nuclear plants and is currently developing new nuclear generation at Plant Vogtle.
- Southern Electric Generating Company ("SEGCO") – is equally owned by Alabama Power and Georgia Power. SEGCO owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities.[12]
- Southern Company Services ("SCS") – the system service company that provides, at cost, specialized services to Southern Company and its subsidiaries;
- Southern Holdings – an intermediate holding subsidiary for Southern Company's investments in leveraged leases; and
- Southern Renewable Energy – formed in January 2010 to construct, acquire, own, and manage renewable generation assets.[13]

[12] Southern Company 2010 10-K, p II-162.
[13] Southern Company 2010 10-K, p. I-1.

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Q. HAVE THE SOUTHERN COMPANY NONREGULATED ACTIVITIES INCREASED IN RECENT YEARS?

A. Yes. Southern Renewable Energy was formed in January 2010 to construct, acquire, own, and manage renewable generation assets.[14] In its 2010 Form 10-K Southern Company stated, "These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk."[15]

Q. ARE THERE TRANSACTIONS BETWEEN GULF POWER AND ITS NONREGULATED AFFILIATES?

A. Yes. Gulf Power contracts with SCS for a variety of managerial and professional services. In addition, it receives mail payment processing services from Alabama Power and shares plant costs with Georgia Power Company for Plant Scherer Unit 3, which is currently excluded from Gulf Power's rate base, and Mississippi Power Company for Plant Daniel. Southern Nuclear provides siting services while SouthernLINC Wireless provides wireless and telecommunications services, and Southern Management provides financial services. Gulf Power provides various services to affiliates as well, including office space, information technology, and power sales.

As shown on Schedule KHD-3, during the projected test year Gulf Power's transactions with its affiliates totaled approximately $155 million. During the test year, nearly $81 million in charges from its affiliates are included in the test year Operations and

[14] Southern Company 2010 10-K, p. I-1.
[15] Southern Company 2010 10-K, p. I-3.

Maintenance ("O&M") and Administrative and General ("A&G") expenses. Thus, of the total O&M and A&G expenses included in the test year of approximately $283 million, 28.6 percent of the costs are charged from its affiliates. In addition, of the total administrative and general expenses included in the test year of $77 million, 73.2 percent, or $56 million are charged from SCS.

Q. HOW HAVE CHARGES FROM SCS CHANGED OVER THE LAST SIX YEARS?

A. Schedule KHD-4 provides the charges from SCS to the Southern Company subsidiaries for the years 2005 to 2010. As shown on this schedule, the charges from SCS to the various Southern Company subsidiaries have increased by $513 million or 57% since 2005. In contrast, charges from SCS to Gulf Power have increased by $44 million or 82% over the same time period. It is interesting to note that SCS' total billings have been increasing. This is partly driven by the fact that the billings to the utility operating companies have been increasing while the amounts billed to the nonregulated companies have been decreasing.

IV. Southern Company Services Allocation of Costs

Q. HOW ARE COSTS FROM SCS ASSIGNED TO GULF POWER AND ITS AFFILIATES?

A. Costs are attributed to affiliates of SCS under three methods: direct assignment, fixed percentage distributions, and direct accumulative distributions.[16] Expenses that are assigned on fixed percentage distributions relate to costs that are incurred for the benefit of two or

[16] Response to OPC Document Request 34 and Supplemental Response to OPC Document Request 34.

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more affiliates. Examples include most administrative and general expenses, which is comprised of certain legal expenses, general accounting functions, human resource functions, and executive management, and miscellaneous expenses.

Q. WHAT IS THE DIRECT ASSIGNMENT METHOD?

A. Costs which are directly assigned from SCS are those that are incurred solely for the benefit of one company. An example of a direct charge could be legal fees incurred in connection with a legal matter specific to Gulf Power.

Q. WOULD YOU EXPLAIN THE DIRECT ACCUMULATIVE DISTRIBUTION METHODOLOGY?

A. Yes. Direct accumulative distributions are based on work order specific allocation assumptions that are used when there is no established fixed percentage allocator that could be used. The Company gave the example of using the number of software seats as a method to allocate costs of acquiring and deploying a particular software program. During the test year $5.2 million of expenses were allocated to the Company using this methodology.[17]

Q. WOULD YOU DESCRIBE THE FIXED PERCENTAGE DISTRIBUTION METHODOLOGY?

A. Expenses that are assigned on fixed percentage distributions relate to costs that are incurred for the benefit of two or more affiliates. Examples include many administrative and general expenses, comprising certain legal expenses, general accounting functions, human resource functions, executive management, and miscellaneous expenses. During the test year, $40

[17] Response to OPC Document Request 34 and Supplemental Response to OPC Document Request 34.

million was charged to the Company using this allocation methodology.[18]

Q. **WHAT ALLOCATION FACTORS DID GULF POWER USE DURING THE TEST YEAR?**

A. The allocation factors used during the test year are shown on Schedule KHD-5. As shown, these factors are made up of various statistics, including kilowatt hours (kWh), customers, employees, plant capacity (kW), gas burned (MMBTU), insurance premiums, billed labor, and a financial factor which consists of an equal weighting of fixed assets, operating expenses, and operating revenue.

Q. **ARE THERE PROBLEMS WITH THE ALLOCATION FACTORS?**

A. Yes. There are several problems with the allocation factors. The problems range from failing to incorporate the significant benefits the nonregulated companies receive from their association with the regulated operating companies to using stale data for the allocation factors.

Q. **WOULD YOU DISCUSS THE BENEFITS THE NONRELATED AFFILIATES RECEIVE FROM THEIR ASSOCIATION WITH REGULATED ELECTRIC COMPANIES?**

A. Yes. However, first the background on the formation of Southern Company and Southern Power is instructive in this analysis, and it demonstrates that the regulated utilities were the foundation for Southern Power and the formation of the service company.

[18] Response to OPC Document Request 34 and Supplemental Response to OPC Document Request 34.

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Q. CAN YOU PLEASE BRIEFLY DESCRIBE THE HISTORY OF SOUTHERN COMPANY?

A. Yes. The genesis of Southern Company began in the mid-1920s when Alabama Power, Georgia Power, Gulf Power, and Mississippi Power became an interconnected system under a holding company known as Southeastern Power & Light. The presumption was that this integration would enable the companies to provide more reliable service, give them a source of capital and construction funds, and allow them to share expert personnel. In 1930, Southeastern Power & Light merged into an eleven-company system called the Commonwealth & Southern Corporation. This corporation was dissolved in the late 1940s because not all of the companies met the requirement of having integrated operations or interconnected transmission lines.

Q. WHEN DID SOUTHERN COMPANY OFFICIALLY FORM?

A. Southern Company was formed on November 9, 1945, as a holding company for Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. In 1949, Southern Company purchased all of the service company's common stock, and the personnel of the holding company became employees of Southern Company Services. Southern Company then began trading on the New York Stock Exchange as SO.

Q. WHEN DID SOUTHERN COMPANY BEGIN DIVERSIFYING ITS OPERATIONS? .

A. In 1981, it formed an unregulated subsidiary, Southern Energy, Inc., which began official operations in January 1982 and grew to serve ten countries on four continents. In January of

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2001, Southern Company spun off Southern Energy into a separate corporation named Mirant Corporation.

Q. HOW ELSE HAS SOUTHERN COMPANY EXPANDED OVER THE YEARS?

A. In 1985 Southern Company formed Southern Company Energy Solutions to research, develop, and invest in new energy-related business opportunities. In 1988, Savannah Electric joined the system as Southern Company's fifth operating company and was merged with Georgia Power on July 1, 2006. Another subsidiary, Southern Nuclear, was formed in 1991 to serve the system's nuclear power plants. Southern Communications Services was formed in 1996 to provide digital wireless communications services to the system. They also marketed these services to the public as SouthernLINC. Southern Telecom was formed as a telecommunications subsidiary in 1997.

Q. HOW DID SOUTHERN COMPANY ADDRESS THE WHOLESALE MARKET?

A. In January 2001, Southern Company formed Southern Power to own, manage, and finance wholesale generating assets in the Southeast for the purpose of targeting wholesale customers. On its website, Southern Company describes Southern Power as "our higher-growth competitive wholesale generation business …."[19]

Q. WHAT ARE SOME OF THE BENEFITS THE NONREGULATED AFFILIATES RECEIVE FROM THEIR ASSOCIATION WITH THE REGULATED OPERATING COMPANIES?

A. The nonregulated companies receive significant benefits of being related to the regulated

[19] http://investor.southerncompany.com/about.cfm.

operating companies. These benefits include the operating companies' reputation, goodwill, and corporate image; being associated with large, financially strong, well-entrenched electric companies; and using the personnel of the service company. All of these benefits are attained because of the regulated operations companies which were the foundation of Southern Company before it ventured into the nonregulated arena. However, at no cost to themselves, the nonregulated affiliates obtain these significant intangible benefits for being associated with the regulated utility operations.

Q. ARE THERE OTHER BENEFITS THAT HAVE RECENTLY BEEN ADDRESSED BY FITCH RATINGS ("FITCH")?

A. Yes. Southern Company's high credit ratings stem in major part to the stable cash flows and financial support provided by the four regulated utility operating companies: Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. Fitch cited this as one reason why it affirmed its stable outlook for Southern Company and each of its operating subsidiaries.[20] Fitch specifically stated:

> Fitch's ratings of Southern recognize the financial support provided by solid utility operating subsidiaries in the form of dividends for the payment of corporate expenses, debt-service, and for other business matters and relatively modest parent debt leverage. The four utilities derive predictable cash flows from regulated businesses and have limited commodity price risks due to the ability to recover fuel through separate cost trackers. There are also periodic cost adjustment mechanisms for other costs such as environmental spending and construction work in process financing costs that limit regulatory lag. Southern's ratings also reflect strong liquidity, financial flexibility, and ready access to the capital markets.[21]

[20] Fitch Ratings, "Fitch Affirms Southern Co. and Subsidiaries' Ratings; Outlook Stable," August 30, 2011.
[21] Fitch Ratings, "Fitch Affirms Southern Co. and Subsidiaries' Ratings; Outlook Stable," August 30, 2011.

Q. LET'S TURN TO THE NEXT PROBLEM WITH THE ALLOCATION FACTORS USED TO ALLOCATE COSTS TO THE COMPANY. ARE THE ALLOCATION FACTORS CURRENT RELATIVE TO THE PROJECTED TEST YEAR?

A. No. Gulf Power used factors based upon 2009 data to allocate projected 2012 expenses. Thus, the data upon which the allocation factors are based are three years behind the dollar values being allocated.[22] If the relationships between the affiliates and the Company are expected to remain constant, then using older allocation factors might be acceptable. However, as demonstrated on Schedule KHD-6, the relationships are not always constant and can vary from year to year including the formation of new affiliates, which require a rebalancing of allocations among the affiliate relationships. Given the magnitude of the dollars that are being allocated, a minor change in the allocation factors can have a meaningful impact. For example, if the financial allocator, which is used to allocate a number of common administrative and general expenses, was modified for Gulf Power by one percent, this could translate into a reduction in test year expenses of $1 million.

Q. HAVE THERE BEEN ANY NEW AFFILIATES ADDED TO THE SOUTHERN COMPANY FAMILY THAT HAVE NOT RECEIVED ANY SCS ALLOCATIONS?

A. Yes. Southern Renewable Energy was formed in 2010 to construct, acquire, own and manage renewable generation.[23] On March 12, 2010, a 30 MW solar photovoltaic plant was purchased by Southern Renewable Energy and on November 25, 2010, the plant began commercial operation. Not only are the SCS overhead costs not allocated to Southern Renewable Energy, but other costs allocated on the basis of MWs were not assigned to this

[22] Company Corrected Supplemental Response to OPC Document Request 34.
[23] Southern Company, 2010 10-K, p. I-1.

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company for the projected test year. Both of these factors overstate the costs included in the Company's projected 2012 test year expenses because the Company used 2009 data to allocate projected 2012 test year expenses.

Q. IS THERE A PROBLEM WITH THE FINANCIAL FACTOR USED TO ALLOCATE COSTS?

A. Yes. As described above, the Company used a "financial" factor to allocate many administrative and general expenses. This factor consists of the average of net fixed assets, operating expenses, and operating revenue.[24] I have concerns that given the differences between the nonregulated companies and the regulated electric companies, including revenue in the allocation factor will overstate the allocations to regulated companies and understate the allocations to the nonregulated companies.

Q. CAN YOU GIVE AN EXAMPLE OF HOW USING THIS COULD BIAS THE ALLOCATION FACTORS?

A. Yes. For example, the revenue per kWh of Gulf Power in 2010 was 9.88 cents, yet Southern Power's revenue per kWh was 4.72 cents. Southern Power sells its power at the wholesale level and therefore its revenue per kWh is lower than the other operating companies. Thus the lower relative level of revenue may not be indicative of the benefits or the level of service provided by SCS to Southern Power.

[24] Southern Company Services Cost Accountability and Control Manual, 2011 Edition, p. 11; Response to OPC Document Request 31.

Q. WHAT ARE THE OTHER PROBLEMS WITH USING A REVENUE ALLOCATION FACTOR?

A. Including a revenue allocation factor tends to under allocate costs to new nonregulated companies. Generally, new companies that are in the start-up phase of operations produce little revenue relative to the level of effort and management activities focused on these new ventures. Similarly, a revenue allocator will tend to over allocate costs to companies that are more capital intensive because they need to generate more revenue to produce the same return on investment as a less capital intensive company.

Moreover, using a revenue allocator will automatically increase the allocation of SCS expenses to Gulf Power (and its sister operating companies) with the implementation of a rate increase, despite the fact that there has been no change in Gulf Power's operations or the effort required by SCS to provide services to Gulf Power. There is no logic to this result, and it clearly demonstrates that the use of a revenue component in the allocation factor is inappropriate.

Allocation factors should be based upon cost-causative relationships to the extent possible and also recognize the benefits received from the service provided.[25]

Q. DO YOU HAVE A SCHEDULE THAT EXAMINES THE COMPONENTS OF THE FINANCIAL ALLOCATOR?

A. Yes. Schedule KHD-7 sets forth the three different factors that make up the financial allocator. As depicted on this schedule, the factors for use in 2011, which were also used for

[25] Accounting for Public Utilities, LexisNexis, 19-11.

the 2012 projected test year, are based upon 2009 data. This schedule shows some interesting relationships. For example, while Southern Company has $18.5 million in assets, it has only $.207 million in operating expenses and $0 in operating revenue.

An examination of the relationship between the operating companies and the unregulated companies tends to show that their operating expense percentages are greater than the net plant percentages; yet when examining the same statistics for Southern Power, its operating expense percentages are much less than the net plant percentages.

Q. ARE THERE ANY PROBLEMS WITH THE EXPENSE FACTORS USED FOR THE FINANCIAL FACTOR?

A. Yes. Although I do not have the components that make up the expenses included in the factor, it appears that the expense portion of the factor includes fuel and purchased power expenses. Fuel and purchased power should not be included in the expense portion of the factor because this factor is used to allocate primarily overhead costs and the administrative and general functions performed by SCS. Including these expenses over allocates costs to the regulated operating companies and under allocates the costs to the nonregulated companies.

Q. HOW DO YOU RECOMMEND THAT THE PROBLEMS IDENTIFIED ABOVE BE CORRECTED?

A. I recommend that the Commission make several adjustments to the allocation factors. First, the Commission should update the data used in the allocation factors, where possible, with

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2010 data. The factors that I was able to update with 2010 data include: Financial Factor, Sales for Resale, Customer, Employee, Employee (Generation), Employee (Transmission), Employee (East), Employee (West), and Capitalization.

Q. WHAT IS THE NEXT CHANGE TO THE ALLOCATION FACTORS THAT YOU RECOMMEND?

A. I recommend that the Commission adjust the financial factor to remove revenue from the composite factor consisting of revenue, net fixed assets, and operating expenses. Including revenue in the allocation factor over allocates costs to the regulated companies and under allocates cost to the nonregulated companies. Revenues are not a good benchmark for allocating overhead-type costs. As explained earlier, a revenue allocator will automatically increase the allocation of SCS expenses to Gulf Power (and its sister operating companies) with the implementation of a rate increase, despite the fact that there has been no change in Gulf Power's operations or the effort required by SCS to provide services to Gulf Power.

I also recommend that the Commission exclude fuel and purchased power from the expense portion of the factor. Including fuel and purchased power will again over allocate costs to the regulated electric companies and under allocate costs to nonregulated companies.

Q. ARE YOU AWARE OF ANY INSTANCES WHERE AN AFFILIATE HAS NOT BEEN ALLOCATED COSTS FROM SCS?

A. Yes. Southern Renewable Energy was a recently formed unregulated affiliate, and to date no costs have been allocated to it from SCS. Thus I believe it is equitable to assess a two percent compensation payment, to be discussed later, to help offset the fact that Southern Renewable Energy was not allocated any of these costs.

Q. ARE YOU AWARE OF ANY AUTHORITATIVE SOURCES THAT RECOGNIZE THE IMPORTANCE OF BENEFITS IN DISTRIBUTING COMMON COSTS?

A. Yes. The Cost Accounting Standards Board (CASB) issues several cost account standards that relate to cost allocations and the allocation of costs to affiliates. The principles outlined by the CASB were succinctly summarized in the publication Accounting for Public Utilities:

> (1) Expenses are to be directly assigned to the maximum extent possible;
> (2) Centralized corporate functions or management staff costs should be accumulated into homogenous cost pools;
> (3) Such cost pools should be allocated using representative bases that reflect cost causation or benefits, where identifiable; and
> (4) Where direct causal relationship or benefits cannot be determined or a direct relevant allocation base cannot be identified, cost pools may be allocated on some other reasonable basis that reflects the benefits of the services received.[26]

Q. DO YOU HAVE A RECOMMENDATION THAT WILL BALANCE THE BENEFITS RECEIVED BY THE NONREGULATED COMPANIES FROM THEIR ASSOCIATION WITH THE REGULATED OPERATING COMPANIES?

A. Yes. I recommend that the Commission assess a two percent compensation payment on the revenue earned by the nonregulated companies. This revenue should be allocated to the regulated companies on the basis of the amount of revenues earned by the nonregulated

[26] Accounting for Public Utilities, LexisNexis, 19-11.

companies. This two percent compensation payment allocated from the nonregulated companies to the regulated operating companies will compensate the regulated operating companies for the significant intangible benefits that the regulated operating companies developed over the years and have provided to the nonregulated companies at no cost simply by their close affiliation and association.

Q. HAS THE COMMISSION IMPOSED A COMPENSATION PAYMENT IN PRIOR CASES?

A. Yes. the Commission imposed such a compensation payment on United Telephone Company of Florida's ("UTF") long distance subsidiary United Telephone Long Distance, Inc. ("UTLD") to ensure customers were compensated for the intangible benefits it receives by the use of the parent company's name, logo, and reputation. In upholding the Commission's decision to impose a compensation payment (which the Supreme Court equated to a royalty), the Supreme Court quoted the following from the Commission's order:

> We [the Commission] find it is in the public interest to require UTLD to compensate UTF for the many intangible benefits it receives, including, but not limited to the following: the use of the United name; the use of the United logo; reliance on the United reputation; immediate access to financing; and the ability to capitalize, through contractual arrangements, on a trained, skilled workforce.
>
> UTLD's relationship to UTF avoids all the start-up costs a fledgling competitor faces when it enters the long distance market. UTF is essentially a one-stop-shopping center for all of UTLD's technical, personnel, administrative, informational and financial needs. We find it unfair to allow UTLD to rely on these benefits without compensating UTF.

> Accordingly, the compensatory fee reflects our belief that these benefits were established and are being maintained by the monopoly company, UTF, at ratepayers' expense. The actual fee to be collected shall equal 2.8% of the difference between net revenues (gross revenues minus uncollectibles) and originating and terminating access charges. However, in no event shall the fee exceed, on an after tax basis, 17.5% of UTLD's net operating income to be computed without the fee....
>
> Finally, we recognize that in the future additional services will be provided by the unregulated entity. The result will be a vast pool of resources developed and maintained at the expense of the monopoly's ratepayers but used increasingly by unregulated operations. Therefore, by our action in this docket, we announce our intention to require payments to regulated utilities for intangible benefits provided to nonregulated affiliates.[27]

The Supreme Court found the compensation payment imposed by the Commission was supported by competent, substantial evidence; authorized by statute; and constitutionally permissible.[28]

Q. WHAT IS THE INCREASE IN REVENUE TO THE COMPANY'S REGULATED OPERATION WITH THE IMPOSITION OF A TWO PERCENT COMPENSATION PAYMENT?

A. A two percent compensation payment assessed against the nonregulated revenue to [redacted] would result in an increase to the Company's test year revenue of $1.5 million.

[27] United Telephone Long Distance, Inc. v Katie Nichols et al., 546 So. 2d 717, 719 (Fla. 1989).[27]
[28] Id. at 720.

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Q. LET'S DISCUSS THE ALLOCATION FACTORS THAT YOU RECOMMEND FOR THE ALLOCATION OF SCS EXPENSES. DO YOU HAVE A SCHEDULE THAT SHOWS YOUR RECOMMENDED ALLOCATION FACTORS?

A. Yes. Schedule KHD-8 depicts the changes to the allocation factors that I recommend. My recommended changes both increase and decrease factors for Gulf Power and the other operating companies.

Q. WHAT IS THE RESULT OF YOUR RECOMMENDED CHANGES TO THE SCS ALLOCATION FACTORS?

A. Schedule KHD-9 shows the impact by FERC account for my recommended changes in the allocation factors. As shown, in total, my recommended allocation factor changes reduce the expenses to the Company by $832,284.

V. Nonregulated Services and Products

Q. LET'S TURN TO THE NEXT SECTION OF YOUR TESTIMONY. DOES THE COMPANY PROVIDE NONREGULATED SERVICES AND PRODUCTS?

A. Yes. The Company offers several products and services that are not regulated nor tariffed by the Commission. The revenues and costs for these products and services appear to be recorded below-the-line for ratemaking purposes. Similar to situations with nonregulated affiliates, because these profits are recorded below-the-line for ratemaking purposes, there is an incentive to shift costs to the regulated operations which will yield higher profits for Gulf Power and its parent company. Like the provision of goods and services between regulated and nonregulated affiliates, the Commission should ensure that the

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regulated operations of Gulf Power do not subsidize the nonregulated operations.

Q. **DOES THE COMMISSION HAVE ANY RULES GOVERNING THE COSTS CHARGED BETWEEN REGULATED AND NONREGULATED OPERATIONS OF ELECTRIC UTILITIES?**

A. Yes. According to the Commission's Cost Allocation and Affiliate Transactions Rule, 25-6.1351(1), F.A.C., the "purpose of this rule is to establish cost allocation requirements to ensure proper accounting for affiliate transactions and *utility nonregulated activities* so that these transactions and activities are not subsidized by utility ratepayers." (emphasis added). Utility nonregulated activities should be covered by this rule, and the Commission can utilize the same principles embodied in subsection (3) of Rule 25-6.1351, F.A.C., as guidelines for examining the relationship between the Company's regulated and nonregulated operations, thus, ensuring that the regulated operations do not subsidize the nonregulated operations.

Q. **DOES THE COMPANY'S COST ACCOUNTABILITY AND CONTROL MANUAL EXPLAIN HOW THE NONREGULATED COSTS AND REVENUES ARE ACCOUNTED FOR RATEMAKING OR ACCOUNTING PURPOSES?**

A. No. There is no discussion in the manual about how the costs associated with providing these services or products are treated for ratemaking or accounting purposes.

Q. **WOULD YOU DESCRIBE THE NONREGULATED SERVICES AND PRODUCTS THAT ARE OFFERED BY THE COMPANY?**

A. Yes. The Company offers three different products and services that are not regulated by the Commission: Premium Surge, Commercial Surge, and AllConnect. Gulf Power describes Premium Surge as a

> … residential program that provides the installation and service of warranted surge protection equipment on a customer's electric meter, telephone and coaxial cable or Satellite TV service entrances, backed by the device manufacturer. The warranty limit is $50,000 per occurrence up to $5,000 per appliance. Fees associated with this product include: $24.99 Install fee; $9.99 monthly service fee (1 meter, 2 phone lines, 1 coaxial cable); $1.50 per additional phone or coaxial line. Installation and service is provided through a third party contractor.[29]

Q. HOW WOULD YOU DESCRIBE COMMERCIAL SURGE?

A. Commercial Surge is a commercial program like the residential program that offers the installation and service of surge protection equipment on a customer's electric service entrance. The warranty limit is $10,000 per occurrence. The cost of the product includes a $50.00 installation fee; a single phase protection fee of 14.99 per month per installed device; and a three-phase protection fee of $19.99 per month per installed device. The Company provides a 10 percent discount for customers with three or more meters. Installation and service is provided through third party contractors.

Q. WHAT IS THE ALLCONNECT PROGRAM?

A. AllConnect is a service designed to allow consumers to select their electricity, local telephone, long distance, cable, home security, and newspaper providers and arrange hook-ups at the time they initiate service with Gulf Power. The Company's customer

[29] Company Response to OPC Interrogatory 65.

service representatives offer this option to the customer upon completion of their phone contact for electric service. The script used by the customer service representatives is shown on Schedule KHD-10. With the customer's permission, they are connected to an AllConnect customer service representative who assists the Gulf customer with the hook-up and initiation of other utilities and services for their home. In return for this referral, AllConnect shares 20 percent of all revenues generated from the customer initiating additional utility or media hook-ups through AllConnect. Gulf does not charge customers for this service.[30] This revenue, however, is booked below-the-line despite the fact that the Company incurs little costs associated with earning this revenue, and this revenue could not be earned if it were not for the regulated operations.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S NONREGULATED OPERATIONS AND HOW ITS COSTS ARE ACCOUNTED FOR RATEMAKING OR ACCOUNTING PURPOSES?

A. I have several concerns. First, there are substantial benefits to the Company's nonregulated operations being associated with the regulated company. These benefits include the use of Gulf Power's name, logo, reputation, goodwill, and corporate image; being associated with a large, financially strong, well-entrenched electric company; use of the personnel; and use of Gulf Power's facilities and website. All of these benefits were developed by the regulated operations. However, the nonregulated operations obtain these significant intangible benefits for being associated with the regulated utility operations at no cost.

[30] Company Response to OPC Document Request 131.

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Q. HAVE YOU EXAMINED ANY DATA WHICH INDICATES THAT GULF POWER'S NONREGULATED OPERATIONS ARE UNDER ALLOCATED COSTS?

A. Yes. I examined the return on net investment earned by the Company's nonregulated operations as a gauge of whether or not the costs have been properly assigned or allocated. To the extent the return on investments appears abnormal, the Commission should be concerned about the attribution of costs between the Company's regulated and nonregulated operations.

Q. WHAT RETURN ON INVESTMENT DID THE COMPANY'S NONREGULATED OPERATIONS EARN?

A. As shown on Schedule KHD-11, based upon the data supplied by the Company for revenues, expenses, and net investment of the nonregulated operations, this segment of Gulf Power earned a return of 21.6 percent in 2009, 24.2 percent for 2010, and 28.9 percent for the projected test year of 2012. Such high returns on investment are abnormal and strongly suggest that the costs attributed to the nonregulated operations are seriously understated.

Q. ARE COSTS ASSIGNED TO THESE PRODUCTS AND SERVICES?

A. Yes. The Company's response to Citizen's Interrogatory 65 indicates that there are direct costs associated with the provision of these nonregulated services and products; however, no overhead costs are allocated or assigned to the Premium Surge and Commercial Surge protection products.[31] Regarding the AllConnect service, the Company's response specifically indicated that "[d]irect labor expenses for Gulf's personnel are charged through Gulf's payroll system."[32]

Q. ARE THE CUSTOMERS THAT PURCHASE THE NONREGULATED SERVICES AND PRODUCTS THE SAME CUSTOMERS TO WHOM THE COMPANY PROVIDES ELECTRIC SERVICE?

A. Yes. All customers that purchase the three nonregulated products and services are Gulf Power ratepayers. There is not one non-ratepayer who purchases these products and services from or through Gulf Power. The ability of the Company to earn an excessive rate of return from these nonregulated products and services is a function of the regulated electric operations and not some extraordinary effort of the Company's nonregulated operations. Without the close association with and good will of the regulated electric utility, Gulf Power could not offer these nonregulated products and services.

Q. HOW CAN THE COMMISSION ENSURE THAT THE REGULATED OPERATIONS DO NOT SUBSIDIZE THE NONREGULATED OPERATIONS?

A. There are at least three options the Commission should consider. First, it could require the Company to properly allocate all overhead costs to the nonregulated operations; however, this fails to consider the significant benefits the nonregulated operations gain from the regulated operations. In addition to allocating costs to the nonregulated affiliates, the Commission should assess a compensation payment for the intangible

[31] Company Response to OPC Interrogatory 254.
[32] Company Response to OPC Interrogatory 65.

benefits the nonregulated operations receive from their association with the regulated electric company. Clearly, there are no overhead costs assigned or allocated to provision of this service. Thus a compensation payment similar to the one set forth in the United Telephone case discussed earlier could be assessed.

Q. WHAT IS THE SECOND METHOD THE COMMISSION CAN USE?

A. The Commission could determine a reasonable rate of return that should be achieved by the nonregulated operations. Anything in excess of this return should be returned to ratepayers.

Q. WHAT IS THE THIRD OPTION?

A. The Commission could move the revenues, expenses, and investments above-the-line for purposes of establishing rates in this proceeding.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission choose the third option that I have offered and essentially treat these revenues, expenses, and investments above-the-line for rate setting purposes. The Company has failed to demonstrate that costs have been properly allocated to these nonregulated operations. In addition, the Company has not shown that it has been compensated for the use of its reputation, goodwill, logo, and trained personnel.

To implement this recommendation, I developed an adjustment to test year revenue by using the return on rate base recommended by Dr. Woolridge of 5.45 percent. The difference between the allowed net operating income and the achieved net operating income, grossed up for income taxes, is the amount of revenue that should be moved above-the-line for rate setting purposes. As shown on Exhibit KHD-12, I recommend an adjustment to test year revenue of $.572 million.

In addition, I recommend that the Commission order the Company to conduct a thorough examination of these operations and develop cost allocation procedures that can be used to allocate costs to these nonregulated operations. These procedures can then be examined and audited as part of the Company's next rate proceeding. However, until the Company properly accounts for these costs, the Commission should treat all amounts above-the-line for ratemaking purposes.

Q. IF THE COMMISSION DOES NOT ADOPT YOUR PRIMARY RECOMMENDATION, DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes. I recommend that the Commission require that the nonregulated operations provide the Company a compensation payment of at least two percent of annual revenue. This is much lower than the high-end of the compensation payment of 17 percent ordered by the Commission in the United Telephone case just discussed which set a maximum of 17 percent of net operating income.

REDACTED VERSION

VI. Other Affiliate Adjustments

Q. DO YOU HAVE ANY OTHER AFFILIATE ADJUSTMENTS?

A. Yes. I have several adjustments that relate to SCS Work Orders charged to Gulf Power which are shown on Schedule KHD-13.

Q. WOULD YOU PLEASE ADDRESS YOUR FIRST ADJUSTMENT?

A. Yes. In response to Citizens' Interrogatory 229, the Company provided some specific details concerning work orders charged to the Company by SCS. Several of these work orders, in my opinion, should not be charged to Gulf Power. For example, the 2012 test year includes $294,765 to support SouthernLINC (a nonregulated affiliate). According to Southern Company's Form 10-K, "SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast."[33] In addition, SouthernLINC was primarily responsible for a decrease in non-electric operating revenues in 2009 and 2010, and Southern Company attributed the decreased revenues of $19 million in 2010 and $25 million in 2009 to "to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry."[34] SouthernLINC's website shows that its regional wireless coverage map coincides with the service territories of Southern Company's regulated utilities.[35]

[33] Southern Company, Form 10-K, p. I-1.
[34] Southern Company, Form 10-K, p. II-19.
[35] SouthernLINC regional coverage map, available at http://www.southernlinc.com/coverage.aspx.

REDACTED VERSION

According to the response to Citizens' Interrogatory 229, all affiliates are responsible for the total SouthernLINC charges that are not able to be recovered through commercial revenues[36] The Company's response indicates that in 2012, the charges to Gulf Power are projected to increase because of the "larger than anticipated drop in commercial customer revenue, thus the total SouthernLINC bill to each affiliate increased."[37] SouthernLINC is an unregulated affiliate, and its losses should not be subsidized by Gulf Power's ratepayers. Therefore, I recommend that the Commission remove $294,765 from the test year associated with the projected increase in 2012 test year expenses, $79,141 of which is related to capital.

Q. **WOULD YOU PLEASE DISCUSS YOUR NEXT ADJUSTMENT?**

A. Yes. The next adjustment shown on Schedule KHD-13 relates to Work Order 466909. According to Gulf, the Work Order relates to a system-wide project to investigate an asset management system to keep track of distribution assets, i.e., poles, switches, reclosers, etc. The Company proposes to increase the dollars associated with this Work Order by $344,204 or 587 percent. This increase in cost was booked to FERC Account 588, Miscellaneous Distribution Expenses. The description of the Work Order suggests that the proposed increase in expenditures should be offset by cost savings, which do not appear to be included in the test year. In addition, the Company has not provided any information regarding the cost effectiveness of the proposed costs. Moreover, the abbreviated description suggests that the costs could be capitalized as opposed to

[36] Company Response to OPC Interrogatory 229.
[37] Company Response to OPC Interrogatory 229.

REDACTED VERSION

expensed. Based upon the Company's failure to justify the increase in costs for this Work Order, I recommend that the costs be disallowed, for an adjustment of $387,596.

Q. WHAT IS YOUR NEXT ADJUSTMENT?

A. My next adjustment relates to Work Order 46C805 for Wireless Systems. According to the Company, after the conversion to Enterprise Solutions, it became necessary for billing from the Georgia Power Company ("GPC") Oakbrook Warehouse to flow through the SCS Work Order system and then get billed to the individual operating companies. This Work Order amounted to $2.2 million charged to Gulf Power. According to the Company's response to Citizens' Interrogatory 229, the "dollars in this Work Order are for capital equipment required for such projects as Converge Networks."[38] Gulf also states that these costs should be offset with a reduction of direct bill materials from GPC. The Company has provided no documentation or other evidence that the savings that will offset these capital dollars have been reflected in the test year. In the absence of such a showing, I recommend that $387,596 be removed from the test year.

Q. WHAT IS YOUR NEXT GROUP OF ADJUSTMENTS?

A. The Citizens requested that the Company provide additional supporting documentation for selected Work Orders included in the test year. The Company was unable to provide several of the requested Work Orders, which show the purpose of the Work Order, the method used to allocate costs, and the client company. I recommend that the Commission disallow all of the expenses associated with these Work Orders since the Company was unable to provide the Work Orders demonstrating the need, the method used to allocate

[38] Response to OPC Interrogatory 229.

the costs, and the company(ies) the costs should be charged to. As shown on Schedule KHD-13, the Work Orders are: 46EZBL, 46IDMU, 46LRBL, 47VSES, 47VSTB, 47VSTH, 47VSZ1, and 47VSZ5. These Work Orders total $190,945. Without supporting documentation for the need of these services, the expenses should be removed from test year expenses, which results in an adjustment of $186,780.

Q. WHY DO YOU RECOMMEND THAT $116,841 BE DISALLOWED FOR THE WORK ORDER ACCOUNTING – COMPTROLLER?

A. According to the description, Work Order 471701 (Accounting-Comptroller) relates to the accumulation of costs associated with a Securities and Exchange Commission inquiry of the Southern Electric System that was initiated in 1989. It is not clear what service is being provided to Gulf and its customers as a result of the Work Order or if the description remains valid today. In the absence of supporting documentation showing that the costs booked to this Work Order are beneficial to Gulf Power and its customers I recommend that the cost in the amount of $116,841 be removed from the test year expenses.

Q. WORK ORDER 473401 STATES THAT IT RELATES TO SOUTHERN COMPANY HUMAN RESOURCES MANAGEMENT. WHY DO YOU RECOMMEND THAT THIS COST NOT BE RECOVERED FROM CUSTOMERS?

A. The description for the increase in Work Order 473401 relative to 2011 indicates that it relates to consulting funds for an outside benefits review. The Company's reason for the budget increase relative to 2011 suggests that this benefits review does not occur on an annual basis. Therefore, I recommend that this expense be amortized over two years and that $18,067 be removed from the test year.

Q. ARE YOU MAKING THE SAME RECOMMENDATION CONCERNING THE WORK ORDER RELATED TO THE CUSTOMER SUMMIT WORK ORDER 49SWCS?

A. Yes. In response to Citizens' Interrogatory 229, the Company explained that the reason for the increase in Work Order 49SWCS from the 2011 budget to the 2012 budget was due to the fact that the customer summit is only held every other year. Therefore, I recommend that $20,831 be removed from the test year to reflect a two-year amortization of this expense.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WORK ORDERS 4Q51RC (SCGEN IT: SUPPORT OF RAILCAR MAINTENANCE) AND 4QPA01 (PAS CENTRAL SYSTEM INTEGRITY)?

A. For both of these work orders, the Company explained that the increase in the expense amount from the 2011 budget to the 2012 budget was due to moving a formerly capitalized item for Work Order 4Q51RC and a formerly CWIP classified Work Order 4QPA01 to expense. The Company has failed to demonstrate these costs should be expensed as opposed to capitalized. It has not provided any evidence that the costs are recurring in nature and should be included in test year expenses. Therefore, I recommend that the Commission reject these proposed reclassifications and reduce test year expenses by $20,102 and $102,411, respectively for these two items.

Q. YOUR SCHEDULE KHD-12 CONTAINS DISALLOWANCES FOR PUBLIC RELATIONS EXPENSES IN THE AMOUNT OF $17,482 ASSOCIATED WITH WORK ORDER 474401. DOES THE COMMISSION TYPICALLY ALLOW THESE TYPES OF EXPENSES?

A. No. The Commission has typically disallowed expenses that are public relations oriented, finding that they benefit stockholders, not customers. When discussing the inclusion of membership dues and contributions in a utility's test year expenses that are public relations oriented, the Commission found:

> We acknowledge that some benefits may be accrued as a result of these expenses. However, we agree with OPC that costs related to contributions and membership dues, which are public relations oriented, should be disallowed. These costs serve to improve the image of the company, resulting in a direct benefit to the utility's shareholders, not to the customers. This treatment has been consistently applied by the Commission, as evidenced by Orders Nos. PSC-93-0301-FOF-WS at 19-20 and PSC 96-1320-FOF-WS at 151-153, which Orders were officially recognized in this proceeding.[39]

In a water and wastewater case involving Southern States Utilities, Inc., the Commission made several findings on what was appropriate to charge customers as it related to public relations-related expenses.

> Mr. Ludsen disagreed with OPC that a public relations retainer is generally not a proper charge for rate case expense. Although he did not know specifics about the charge, Mr. Ludsen stated that the uniform rate investigation benefitted this case because of broader customer input. Mr.

[39] Florida Public Service Commission, United Water Florida Inc., Docket No. 960451-WS PSC-97-0618-FOF-WS, May 30, 1997.

REDACTED VERSION

Ludsen did not think that SSU was trying to enhance its image, but instead trying to inform customers through brochures about the issues in the case.

When asked about legislative charges from the Messer Vickers law firm, Mr. Ludsen could not explain to what those related. He agreed, in general, that legislative expenses should not be charged to customers. Specifically, Mr. Ludsen agreed that charges from Landers and Parsons for preparing testimony for a Senate hearing should be removed.

Mr. Ludsen's response to why open houses with customers, in addition to the Commission hearings, should be charged to customers was that it was a benefit to the case. If it benefitted the case, then it benefitted the customers. He did admit that those open houses were not required by the Commission.

...

We believe that if SSU sees a need to inform its customers or the press about the issues in the case beyond what our rules require, then those expenditures must be borne by SSU, not the customers. Accordingly, all charges related to telemarketing, public relations, uniform rate bill inserts, mailings and door hangers, cellular telephone bills and bus transportation shall be removed. Mr. Ludsen was unable to justify why a banquet or lunch was necessary and reasonable; accordingly, this amount shall be removed. As agreed to by Mr. Ludsen, any legislative or lobbying charges shall also be removed.[40]

Furthermore, the Commission ordered that image-enhancing advertising expenses be removed in Gulf Power's last rate case:

We find that the ads in Part C of Exhibit 22 are purely image enhancing. Gulf does not refute this. For this reason the cost of the ads shall not be included in base rates, and Gulf shall not be allowed to recover the advertising expense of $539,000 ($550,000 system).[41]

Based upon past precedent, the Commission should continue its policy and remove these expenses from the test year.

[40] Florida Public Service Commission, Southern States Utilities, Inc. Docket No. 950495-WS; Order No. PSC-96-1320-FOF-WS, October 30, 1996.
[41] Florida Public Service Commission, Gulf Power Company. Docket No. 010949-EI; Order No. PSC-02-0787-FOF-IE, June 10, 2002.

REDACTED VERSION

Q. WHAT IS YOUR RECOMMENDATION ABOUT WORK ORDER 471501 (INVESTOR-RELATIONS-GENERAL)?

A. I recommend that the Commission move this item below-the-line for ratemaking purposes. This expense is for the benefit of stockholders, not ratepayers. The Commission has removed costs related to shareholder costs in prior rate cases. In Order No. PSC-96-1320-FOF-WS, the Commission found that:

> Through the ROE leverage formula, we have allowed recovery of costs associated with being a publicly traded utility. Specifically, in the calculation of the appropriate cost of equity, we recognized an additional 25 basis points to the otherwise determined cost of equity to provide for these costs. To ask SSU's ratepayers to pay 25 basis points on ROE in addition to the amount requested by SSU would be duplicative. We also question whether the benefits SSU receives from MP&L are worth $208,776 to the ratepayers in Florida. Consequently, we shall disallow all of the utility's requested shareholder services expenses of $208,776.[42]

I recommend that the Commission continue its practice and remove these expenses, in the amount of $96,851 from the test year.

Q. WOULD YOU ADDRESS WORK ORDERS 473ECO AND 473ECS?

A. Yes. These two Work Orders are related to Chief Operating Officer legal expenses and External Affairs legal matters. It is not clear that the costs charged to these two accounts benefit ratepayers. Therefore, unless the Company is able to demonstrate that these expenses are beneficial to ratepayers, I recommend that they be excluded from test year expenses. As shown on Schedule KHD-12 they amount to $33,690.

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[42] Florida Public Service Commission, Southern States Utilities, Inc. Docket No. 950495-WS; Order No. PSC-96-1320-FOF-WS, October 30, 1996.

REDACTED VERSION

Q. WHAT IS YOUR RECOMMENDATION CONCERNING WORK ORDER 486030 RELATED TO AIRCRAFT?

A. The increase in expenses for Work Order 486030 from the test year relate to an unexplained increase in aircraft expenses and amount to a 97 percent increase over the 2011 amount. I recommend that the increase over the budgeted 2011 amount be removed from test year expenses. The adjustment to test year expenses is $101,859. In addition, there is outstanding discovery on aircraft lease expenses that were being negotiated between OPC and the Company at the time of the filing of my testimony. Depending on the timing of these negotiations and the additional information supplied by the Company, it may be necessary to supplement my testimony on these expenses.

Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENT THAT YOU RECOMMEND CONCERNING THE WORK ORDERS JUST DISCUSSED?

A. As shown on Schedule KHD-13 the adjustments reduce total company test year capital by $.467 million and expenses by $1.3 million.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

BY MR. SAYLER:

Q. And you have prepared a summary of your testimony today?

A. Yes, I have.

Q. All right. Would you please summarize your testimony for this Commission?

A. Yes. Good morning, Commissioners. My testimony addresses the transactions between Gulf Power and its affiliates. Gulf Power is a wholly owned subsidiary of Southern Company. Southern Company has both regulated and non-regulated subsidiaries. Gulf Power had nearly $81 million in transactions with its affiliates during the test year. The majority of Gulf Power's affiliate transactions are with Southern Company Services, of which $56 million was included in the test year.

It's important to closely examine affiliate transactions to ensure that customers of the regulated utility are not subsidizing the operations of the non-regulated companies. This Commission has consistently held that the standard in evaluating affiliate transactions is whether or not they exceed the going market rate or are otherwise inherently unfair.

In the first section of my testimony, I examine the methodology used to allocate costs from

Southern Company Services to Gulf Power and its sister companies. Southern Company Services provides a variety of services to Gulf Power and also to non-regulated companies. The services provided by Southern Company Services include, but is not limited to, legal, accounting, human resource, customer operations, engineering, information resources, and executive management.

Southern Company's non-regulated subsidiaries receive significant benefits from their association with Gulf Power and its sister operating companies. These benefits include the operating company's reputation, goodwill, corporate image, being associated with a large, financially strong, well-entrenched electric companies, and using the personnel of Southern Company Services, who was established for the purposes of serving the regulated companies.

The balance of the significant benefits received by non-regulated companies from their association with -- to balance, I'm sorry, to balance the significant benefits that Gulf Power receives from being associated with -- let me start over.

To balance significant benefits received by the non-regulated companies from their association with Gulf Power, I recommend that the Commission assess a

2 percent compensation payment on the revenue earned by the non-regulated affiliates. This recommendation results in an increase to Gulf Power's test year revenue of $1.5 million.

My next recommendation focuses on the allocation factors used to distribute costs from Southern Company Services to Gulf Power and Southern Company's non-regulated affiliates. There are several problems with these allocation factors.

First, the factors used to allocate projected 2012 expenses were based on 2009 data. I recommend that the Commission adopt the changes that I recommend and use the factors using 2010 data.

Second, the 2012 test year allocations do not consider the impact of Southern Renewable Energy, which was formed in 2010. Therefore, the costs from Southern Company Services have not been allocated to this non-regulated company.

Third, the financial allocation factor, which distributes a significant portion of the administrative and general expenses, has several problems. For example, including revenue in the financial factor tends to allocate costs to -- tends to underallocate costs to the new non-regulated companies and overallocate costs of the well-entrenched electric companies. New startup companies like Southern Renewable Energy produce little revenue, but yet they require a much greater level of effort from management. On the expense side, the financial factor includes fuel and purchased power, which overallocates costs to the regulated companies.

To overcome these problems, I recommend that the Commission remove the revenue component from the financial allocation factor and to remove the fuel and purchased power expenses from the expense component of the factor. My recommended adjustments would reduce test year expenses by $832,000.

I am also addressing Gulf Power's non-regulated operations. Gulf Power offers three different non-regulated products and services, specifically, Premium Surge, Commercial Surge, and AllConnect. Again, there are substantial benefits to Gulf Power's non-regulated operations of being associated with the regulated company. In addition, all of the companies that purchase these three services are Gulf Power ratepayers.

I recommend that the Commission treat these revenues, expenses, and investments above the line for ratemaking purposes. For all intents and purposes, Gulf Power and its stockholders bear little or no risk that might suggest that the earnings of these non-regulated services and products should be recorded below the line. My adjustment would increase test year revenue by $572,000.

My final recommendation relates to specific service company work orders that I recommend be removed from the test year. My adjustments in this area lack supporting details -- because of lacking supporting details, I recommend that be test year investments be reduced by $467,000 and test year expenses be reduced by 1.4 million.

That completes my summary.

COMMISSIONER BROWN: We tender our witness for cross.

CHAIRMAN GRAHAM: Intervenors? Staff?

CROSS-EXAMINATION

BY MR. YOUNG:

Q. Ms. Dismukes, do you have your testimony with you?

A. Yes, I do.

Q. Can you turn to your Exhibit KHD-13?

A. Okay.

Q. At the bottom of KHD-13, "Capitalized," do you see that?

A. Yes, I do.

Q. And you see FERC account number 308?

A. Yes.

Q. Is that the correct account number?

A. That is the account number that was provided by the company. We asked them to map the work orders to the FERC accounts, and in their response to the Citizens' Sixth Set of Interrogatories, Interrogatory 229 -- it's actually on page 7 -- that account number is reflected for that particular work order.

Q. Subject to check, if the response to the interrogatory had a different account number, that number would change to that account; correct?

A. Yes.

MR. YOUNG: All right. No further questions.

CHAIRMAN GRAHAM: Commissioners? Commissioner Brown.

COMMISSIONER BROWN: Just one question. Good morning, Ms. Dismukes. Nice to see you back.

THE WITNESS: Thanks.

COMMISSIONER BROWN: Do you happen to know why Gulf used 2009 data in the allocation factors?

THE WITNESS: They indicated, I believe, in their rebuttal testimony that -- and they did update it in their rebuttal testimony -- that it wasn't available at the time they filed their rate case, but that's not correct. They filed their rate case -- I believe it was in July of 2011. Is that right?

And usually your financial information, 10-Ks and information like that is available in April. So the information would have been available to them in a formal setting by April, and it would have been informally available to them in a period before that.

COMMISSIONER BROWN: Okay. Thank you.

CHAIRMAN GRAHAM: Redirect?

MR. SAYLER: No, sir.

CHAIRMAN GRAHAM: Exhibits.

MR. SAYLER: The Office of Public Counsel would move in Ms. Dismukes' exhibits on page 12, and they're numbered 39 through 51.

CHAIRMAN GRAHAM: Page 11?

MR. SAYLER: Page 11, yes, sir.

CHAIRMAN GRAHAM: Thirty-nine --

MR. SAYLER: Through 51.

CHAIRMAN GRAHAM: Through 51 will be entered into the record.

(Exhibit Numbers 39 through 51 were admitted into the record.)

MR. SAYLER: And Number 207 on page 32.

CHAIRMAN GRAHAM: And enter 207.

(Exhibit Number 207 was admitted into the record.)

THE COURT: And may our witness be excused?

CHAIRMAN GRAHAM: If there's no objections, we will excuse the witness.

MR. SAYLER: Thank you, Mr. Chairman. Thank you, Ms. Dismukes.

CHAIRMAN GRAHAM: Next witness?

MR. McGLOTHLIN: OPC calls Dr. J. Randall Woolridge.

Dr. Woolridge, have you been sworn?

THE WITNESS: No, I haven't been. I have not.

CHAIRMAN GRAHAM: Is there anybody else in the audience that has not been sworn that's going to testify?

(Witness sworn.)

Thereupon,

J. RANDALL WOOLRIDGE

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. McGLOTHLIN:

Q. Please state your name and your business address.

A. My name is the initial J. Randall Woolridge, and that's spelled W-o-o-l-r-i-d-g-e. My business address is 310 South Allen Street, State College, Pennsylvania.

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

A. I'm a professor of finance at Penn State University.

Q. Dr. Woolridge, at our request did you prepare and submit on behalf of the Office of Public Counsel direct testimony in this docket on October 14, 2011?

A. Yes.

Q. Do you have that before you?

A. Yes.

Q. And have you prepared an errata sheet to that testimony?

A. Yes.

MR. McGLOTHLIN: We have distributed that and ask for a number to be assigned.

CHAIRMAN GRAHAM: We'll assign Number 208 to that. We'll call it Errata to Woolridge Direct Testimony?

MR. McGLOTHLIN: Yes.

(Exhibit Number 208 was marked for identification.)

BY MR. McGLOTHLIN:

Q. Other than the changes reflected on the errata sheet, Dr. Woolridge, do you have any changes or corrections to make to your prefiled testimony?

A. No.

Q. Do you adopt that prefiled testimony as your testimony here today?

A. Yes.

Q. Did you also prepare some exhibits that accompanied the prefiled testimony?

A. Yes.

MR. McGLOTHLIN: They're been assigned Exhibits 52 through 65 inclusive. And I request that the prefiled testimony be inserted at this point.

CHAIRMAN GRAHAM: We will insert Dr. Woolridge's prefiled direct testimony into the record as though read.

DIRECT TESTIMONY

OF

J. RANDALL WOOLRIDGE

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 110138-EI

I. IDENTIFICATION OF WITNESS AND SUMMARY OF TESTIMONY

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Exhibit JRW-1.

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

A. I have been asked by the Florida Office of Public Counsel ("OPC") to provide an opinion as to the overall fair rate of return or cost of capital for Gulf Power Company ("Gulf Power" or "Company") and to evaluate Gulf Power's rate of return testimony in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review my cost of capital recommendation for Gulf Power. Second, I provide an assessment of capital costs in today's capital markets. Third, I discuss the selection of a proxy group of electric utility companies for estimating the cost of capital for Gulf Power. Fourth, I present my recommendations for the Company's capital structure and debt cost rate. Fifth, I discuss the concept of the cost of equity capital, and then estimate the equity cost rate for Gulf Power. Sixth, I provide a critique of Gulf Power's rate of return testimony. Finally, I discuss why it is appropriate to include a parent debt adjustment to Gulf's income tax expense calculation.

Q. PLEASE REVIEW YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR GULF POWER.

A. I have employed the Company's proposed capital structure, but I adjusted the Company's proposed short-term and long-term cost rates. I applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a proxy group of publicly-held electric utility companies ("Electric Proxy Group"). My analysis indicates that an equity cost rate of 9.25% is appropriate for Gulf Power. Using my capital structure and debt and equity cost rates, I recommend an overall rate of return of 5.89% for Gulf Power. This recommendation is summarized in Exhibit JRW-2. On another related matter, I also provide an evaluation of Mr. Teel's discussion of the Parent Debt Adjustment Rule 25-14.004, F.A.C.

Q. PLEASE SUMMARIZE THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. Gulf Power witness Mr. Richard J. McMillan provides the Company's proposed capital structure and long-term debt cost rate, and Dr. James H. Vander Weide recommends a common equity cost rate for Gulf Power. Gulf Power's recommended capital structure includes 1.30% short-term debt, 47.83% long-term debt, 5.31% preferred stock, and 46.87% common equity. Gulf Power uses short-term and long-term debt cost rates of 2.12% and 5.45%, a preferred stock cost rate of 6.65% and an equity cost rate of 11.7%.

I have used the Company's proposed capital structure ratios. I have adjusted the proposed short-term and long-term debt cost rates and the preferred stock cost rate to reflect current market interest rates. I have recommended an equity cost rate of 9.25% for Gulf Power. Gulf Power witness Dr. James H. Vander Weide's proposed common equity cost rate is 11.7%. Both Dr. Vander Weide and I have applied the DCF and the CAPM approaches to a proxy group of publicly-held companies. Dr. Vander Weide has also used a Risk Premium ("RP") approach to estimate an equity cost rate for Gulf Power. Dr. Vander Weide employs a proxy group of twenty-four electric utilities. I have employed a proxy group of twenty-eight electric utilities that is quite similar to Dr. Vander Weide's group. In his DCF approach, Dr. Vander Weide uses a quarterly DCF model and relies exclusively on the projected earnings per share ("EPS") growth rates of Wall Street analysts. I provide empirical evidence that demonstrates the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased. Consequently, in developing a DCF growth rate, I have used both historic and projected growth rate measures and have evaluated growth in dividends, book value, and earnings per share.

The RP and CAPM approaches require an estimate of the base interest rate and the equity risk premium. In both approaches, Dr. Vander Weide's base interest rate is above current market rates. However, the major area of disagreement involves our significantly different views on the alternative approaches to measuring the equity risk premium, as well as the magnitude of equity risk premium. Dr. Vander Weide's equity risk premiums are excessive and do not reflect current market fundamentals. As I highlight in my testimony, there are three methodologies for estimating an equity risk premium – historic returns, surveys, and expected return models. Dr. Vander Weide uses a historical equity risk premium which is based on historic stock and bond returns. He also calculates an expected risk premium in which he applies the DCF approach to the S&P 500 and public utility stocks. I provide evidence that risk premiums based on historic stock and bond returns are subject to empirical errors which result in upwardly biased measures of expected equity risk premiums. I demonstrate that Dr. Vander Weide's projected equity risk premiums, which use analysts' EPS growth rate projections, include unrealistic assumptions regarding future economic and earnings growth and stock returns. Finally, I demonstrate that Dr. Vander Weide's market and equity risk premiums are well above the market and equity risk premiums used in the real world of finance.

Finally, Dr. Vander Weide makes two unwarranted adjustments in developing an equity cost rate. In his DCF, RP, and CAPM approaches, Dr. Vander Weide makes an unnecessary adjustment for flotation costs. This serves to inflate his DCF equity cost rate. In addition, Dr. Vander Weide also makes an overall leverage adjustment to his equity cost rate estimate. This adjustment is based on the leverage difference between the market value capital structures of his electric utility group and Gulf Power's book value capital structure, which is used for ratemaking purposes. The adjustment increases his equity cost rate estimate by 90 basis points. In my testimony I discuss why this adjustment is not appropriate and highlight the fact that it produces illogical results.

In the end, the most significant areas of disagreement in measuring Gulf Power's cost of capital are: (1) the appropriate debt and preferred stock cost rates; (2) the dividend yield in the quarterly DCF model; (3) Dr. Vander Weide's exclusive use of the projected growth rates of Wall Street analysts to measure expected DCF growth; (4) the base interest rate as well as the market or equity risk premium in the RP and CAPM approaches; (5) Dr. Vander Weide's unwarranted flotation cost adjustments to his equity cost rate results; and (6) an erroneous leverage adjustment based on the market value capital structures of his proxy group.

II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN U.S. MARKETS.

A. Long-term capital cost rates for U.S. corporations are a function of the required returns on risk-free securities plus a risk premium. The risk-free rate of interest is the yield on long-term U.S Treasury bonds. The yields on ten-year U.S. Treasury bonds from 1953 to the present are provided on page 1 of Exhibit JRW-3. These yields peaked in the early 1980s and have generally declined since that time. In the summer of 2003, these yields hit a 60-year low at 3.33%. They subsequently increased and fluctuated between the 4.0% and 5.0% levels over the next four years in response to ebbs and flows in the economy. Ten-year Treasury yields began to decline in mid-2007 at the beginning of the current financial crisis. In 2008 Treasury yields declined to below 3.0% as a result of the expansion of the mortgage and subprime market credit crisis, the turmoil in the financial sector, the government bailout of financial institutions, and the economic recession. Overall, these economic developments led investors to seek out low risk investments. These yields have declined from 2.5% to just below 2.0% during the past six months.

Panel B on page 1 of Exhibit JRW-3 shows the differences in yields between ten-year Treasuries and Moody's Baa rated bonds since the year 2000. This differential primarily reflects the additional risk required by bond investors for the risk associated with investing in corporate bonds. The difference also reflects, to some degree, yield curve changes over time. The Baa rating is the lowest of the investment grade bond ratings for corporate bonds. The yield differential hovered in the 2.0% to 3.0% area until 2005, declined to 1.5% until late 2007, and then increased significantly in response to the current financial crisis. This differential peaked at 6.0% at the height of the financial crisis in early 2009, due to tightening in credit markets, which increased corporate bond yields, and the "flight to quality," which decreased treasury yields. The differential subsequently declined and has been in the 2.5% range over the past six months.

As previously noted, the risk premium is the return premium required by investors to purchase riskier securities. The risk premium required by investors to buy corporate bonds is observable based on yield differentials in the markets. The equity risk premium is the return premium required to purchase stocks as opposed to bonds. The equity risk premium is not readily measurable in the markets (as are bond risk premiums) since expected stock market returns are not readily observable. As a result, equity risk premiums must be estimated using market data. There are alternative methodologies to estimating the equity risk premium, and the alternative approaches and equity risk premium results are subject to much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5% to 7% range. However, studies by leading academics indicate the forward-looking equity risk premium is actually in the 4.0% to 5.0% range. These lower equity risk premium results are in line with the findings of equity risk premium surveys of CFOs, academics, analysts, companies, and financial forecasters.

Q. PLEASE DESCRIBE HOW THE FINANCIAL CRISIS HAS IMPACTED THE FINANCIAL MARKETS.

A. United States Treasury Rates have declined to levels not seen since the 1950s. This reflects the "flight to quality" in the credit markets, as investors have sought out low risk investments, and the massive monetary stimulus provided by the Federal Reserve Board. The credit market for corporate and utility debt experienced higher rates during the financial crisis.

However, the long-term credit market has improved significantly. The credit crisis was associated with concerns among credit providers – mainly financial institutions – in terms of making loans and investing in bonds due to the overleveraging and perceived weakness of the economy. Panel A of page 2 of Exhibit JRW-3 provides the yields on A, BBB+, and BBB rated public utility bonds. These yields peaked in November 2008, declined by about 200 to 300 basis points ("BPs") through the summer of 2010, and have since increased about 50 to 75 BPs. For example, the yields on "A" rated utility bonds, which peaked at over 7.50% in November of 2008, declined to 5.0% to 6.0% range in 2010. They have recently declined to the 4.5% range. Panel B of page 2 of Exhibit JRW-3 provides the yield spreads on A, BBB+, and BBB rated public utility bonds relative to Treasury bonds. These yield spreads increased dramatically in the third quarter of 2008 during the peak of the financial crisis and have since decreased to pre-crisis levels. For example, the yield spread between 30-year, 'A' rated utility bonds and 30-Year Treasury bonds, increased from 1.5% to 3.5% in November of 2008. This yield spread deceased to below 1.5% as of the summer of 2009, and has since declined below this figure.

In sum, while the economy continues to face significant problems, the actions of the government and Federal Reserve had a large effect on the credit markets. The capital costs for utilities, as measured by the yields on 30-year utility bonds, have declined to pre-financial crisis levels.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR GULF POWER.

A. To develop a fair rate of return recommendation for Gulf Power, I evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies ("Electric Proxy Group").

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF COMPANIES.

A. My Electric Proxy Group consists of twenty-eight electric utility companies. The selection criteria include the following:

1. Listed as Electric Utility by *Value Line Investment Survey* and listed as an Electric Utility or Combination Electric & Gas company in *AUS Utilities Report*;
2. At least 50% of revenues from regulated electric operations as reported by *AUS Utilities Report;*

3. An investment grade bond rating as reported by *AUS Utilities Report;*

4. Pays a cash dividend;

5. Not involved in an acquisition of another utility, and/or was not the target of an acquisition, in the past year; and

6. Analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters, and Zacks.

The Electric Proxy Group includes twenty-eight companies. Summary financial statistics for the proxy group are listed on page 1 of Exhibit JRW-4.[1] The median operating revenues and net plant for the Electric Proxy Group are $4,078.0M and $8,678.4M, respectively. The group receives 79% of revenues from regulated electric operations, has an A-/BBB+ bond rating from Standard & Poor's, a current common equity ratio of 45.4%, and an earned return on common equity of 10.3%.

IV. <u>CAPITAL STRUCTURE RATIOS AND DEBT COST RATES</u>

Q. WHAT IS GULF POWER'S CURRENT CAPITAL STRUCTURE FOR RATEMAKING PURPOSES?

A. Gulf Power's recommended capital structure as for ratemaking purposes of December 31, 2012, includes 1.70% short-term debt, 39.29% long-term debt, 4.36% preferred stock, 38.50% common equity, 1.27 % customer deposits, 15.34% deferred taxes, and 0.17% investment tax credit. Gulf Power's recommended capital structure for investor sources includes 1.30% short-term debt, 47.83% long-term debt, 5.31% preferred stock, and 46.87% common equity.

[1] In my testimony, I present financial results using both mean and medians as measures of central tendency. However, due to outliers among means, I have used the median as a measure of central tendency.

Q. WHAT CAPITAL STRUCTURE ARE YOU EMPLOYING FOR GULF POWER?

A. I am using the Company's recommended capital structure. Page 2 of Exhibit JRW-5 provides the capital structures for Gulf Power and Southern Company. The Company's recommended capital structure is in line with its recent capital structure as well as the capital structure of Southern Company. In addition, as discussed above, the current common equity ratio for the Electric Proxy Group is 45.4%.[2]

Q. WHAT SENIOR CAPITAL COST RATES ARE HAVE BEEN USED BY GULF POWER?

A. The Company uses projected short-term and long-term debt cost rates of 2.12% and 5.45% and a preferred stock cost rate of 6.65%. These projections were made as of September 2010. The short-term debt cost rate is based on a projected London Interbank Offered Rate ("LIBOR") rate of 3.15% as of December 31, 2012. The current LIBOR rate is 0.25%. The long-term debt cost rate includes bond issues at 6.50% in 2011, and 8.05% and 7.70% in 2012. These projected rates are based on the yields on long-term U. S. Treasury bonds plus 190 basis points. The current yield on long-term U. S. Treasury bonds 2.80%. In addition, the current yield on long-term utility bonds is below 5.0%. Finally, the preferred stock cost rate includes a new issue at 7.45%, which is based on the long-term Treasury yields that are well above current yields.

Q. WHAT SENIOR CAPITAL COST RATES ARE YOU USING IN YOUR COST OF CAPITAL CALCULATION FOR GULF POWER?

[2] OPC witness Ramas has recommended an adjustment in her testimony to Accumulated Deferred Income Taxes which has not been reflected in my recommended capital structure amounts.

A. As indicated above, the senior capital cost rates developed by the Company were developed in September of 2010 and are based on projected short-term and long-term interest rates that are well in excess of the interest rates in the market today. Therefore, I am using the Company's projected 2011 senior capital cost rates as provided in MFR D-3, D-4, and D-5. I have made one adjustment to the long-term debt cost rate. The Company estimated a yield of 6.50% for a projected bond issue in April of 2011. The actual yield on the bonds issued in May of this year was 5.75%. With this adjustment, the short-term, long-term, and preferred stock cost rates as projected by Gulf Power are 0.35%, 4.98%, and 6.40%. These are the senior capital cost rates I have used in developing a cost of capital for Gulf Power.

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, are sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

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.

[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I performed a regression study between estimated return on equity ("ROE") and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Panels A-C of Exhibit JRW-6. The average R-squares for the electric, gas, and water companies are 0.65, 0.60, and 0.92, respectively.[5] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

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[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

[5] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

A. Exhibit JRW-7 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on long-term 'A' rated public utility bonds. These yields peaked in the early 2000s at over 8.0%, declined to about 5.0% in 2005, and rose to 6.0% in 2006 and 2007. They stayed in that 6.0% range until the third quarter of 2008 when they spiked to almost 7.5% during the financial crisis. They have since retreated and are now below 5.0%.

Page 2 of Exhibit JRW-7 provides the dividend yields for the proxy group. The dividend yields for the Electric Proxy Group generally declined slightly over the decade until 2007. They increased in 2008 and 2009 in response to the financial crisis, but declined in 2010 to about 4.75%.

Average earned returns on common equity and market-to-book ratios for the group are on page 3 of Exhibit JRW-7. The average earned returns on common equity for the Electric Proxy Group were in the 9.0%-12.0% range over the past decade, and ended 2010 at 9.75%. The average market-to-book ratio for the group has been in the 1.20X to 1.80X during the decade. The average declined to about 1.20X in 2009, but increased to 1.30X in 2010.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-8 provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey* and are compiled annually by Aswath Damodoran of New York University.[6] The study shows that the investment risk of utilities is very low. The average beta for electric, water, and gas utility companies are 0.75, 0.70, and 0.65, respectively. These are well below the *Value Line* average of 1.15. As such, the cost of equity for utilities is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

[6] *Available* at http://www.stern.nyu.edu/~adamodar.

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the discounted cash flow ("DCF") model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my experience that this Commission has traditionally relied on the DCF method. I have also performed a capital asset pricing model ("CAPM") study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. DCF Analysis

Q. DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \dots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-9. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive ROEs. At that time its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. 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). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT JRW-10.

A. My DCF analysis is provided in Exhibit JRW-10. The DCF summary is on page 1 of this Exhibit, and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages of the Exhibit.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR THE PROXY GROUP?

A. The dividend yields on the common stock for the companies in the proxy group are provided on page 2 of Exhibit JRW-10 for the six-month period ending October 2011.

For the DCF dividend yields for the Group, I use the average of the six month and October 2011 dividend yields. The table below shows these dividend yields.

Proxy Group	October 2011 Dividend Yield	6-Month Average Dividend Yield	DCF Dividend Yield
Electric Proxy Group	4.4%	4.5%	4.45%

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4 and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, that pays dividends on a quarterly basis.[7]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

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[7] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

A. I will adjust the dividend yield by one-half (1/2) the expected growth, so as to reflect growth over the coming year.

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUP?

A. I have analyzed a number of measures of growth for companies in the Electric Proxy Group. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as published by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to virtually all investors and are presumably an important ingredient in forming expectations concerning future growth. 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.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. ARE YOU RELYING EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. No. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, and most significantly, it is well known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. This issue is addressed in later in my testimony.

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth rate forecasts, and therefore, stock prices reflect the upward bias. In other words, investors compensate for the upward bias in analysts' EPS growth rate forecasts by paying a lower price for the stock.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

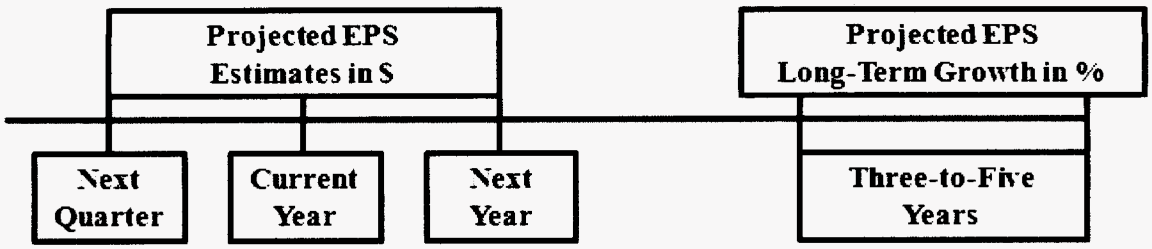
A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Since stock prices reflect the bias, it would affect the dividend yield. But, in the application of the DCF model, the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias.

Q. PLEASE DISCUSS THE SERVICES THAT PROVDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by a number of different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call and Reuters, among others. These services solicit and publish the EPS forecasts of analysts of investment and financial service firms and publish the average EPS estimates for future quarterly and annual time periods as well as the average long-term EPS growth rate forecasts.

Q. PLEASE PROVIDE AN EXAMPLE OF THESE EPS FORECASTS.

A. The following example provides the EPS forecasts compiled by Reuters for ALLETE Resources. The EPS estimates are in dollars and cents per share, and the services report the high, low and mean of the estimates collected for analysts. The long-term projected EPS growth rate is expressed in percentage terms. As shown in the figure below, the projected EPS near-term estimates are usually provided for the next quarter, the current fiscal year, and the next fiscal year. The long-term projected EPS growth rate is for a three-to-five year time period.



Consensus Earnings Estimates
ALLETE, Inc
www.reuters.com
August 5, 2011

	# of Estimates	Mean	High	Low
Earnings (per share)				
Quarter Ending Sep-11	4	0.54	0.57	0.51
Quarter Ending Dec-11	4	0.60	0.65	0.55
Year Ending Dec-11	4	2.50	2.60	2.45
Year Ending Dec-12	4	2.62	2.65	2.60
LT Growth Rate (%)	4	5.75	8.00	5.00

These figures can be interpreted as follows. The top line shows that four analysts provided EPS estimates for the quarter ending September 2011. The mean, high and low estimates are $0.54, 0.57, and $0.51, respectively. The second line shows the quarterly EPS estimates for the quarter ending December 2011. Lines three and four show the annual EPS estimates for the fiscal years ending December 2011 and 2012. The quarterly and annual EPS forecasts in lines 1-4 are expressed in dollars and cents. The long-term growth rate is expressed as a percent. For ALLETE, four analysts have provided long-term EPS growth rate forecasts, with mean, high and low growth rates of 5.75%, 8.00%, and 5.00%.

Q. WHICH OF THESE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. The DCF growth rate is the long-term projected growth rate in EPS, DPS, and BVPS. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model.

Q. PLEASE DISCUSS THE ISSUES IN USING THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings grow at a similar growth rate. Second, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. This issue is discussed at length later in my testimony.

Q. PLEASE DISCUSS THE DIFFERENT SOURCES OF ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS

A. Thompson Reuters, based in New York, is a major provider of investment information and publishes analysts' EPS forecasts under different names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks are independently owned and publish their own set of analysts' EPS forecasts for companies. As far as I am aware, none of these services reveal: (1) the analysts who are solicited for forecasts; or (2) the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. Thompson Reuters and Zacks do provide limited EPS forecasts data free-of-charge on the internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as msn.money (http://money.msn.com). As such, Thompson Reuters and Zacks are the ultimate sources of EPS forecasts that are provided free-of-charge at different sites on the internet.

Q. WHAT ARE YOUR OBSERVATIONS ON THE ALTERNATIVE SOURCES OF ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS?

A. It is my experience that there is not one single figure that represents analysts' projected EPS growth rate for a company. Page 5 of Exhibit JRW-10 provides analysts' projected EPS growth rates for the proxy group companies as published by Reuters, Yahoo, and Zacks. These are the primary providers of analysts' EPS growth rate forecasts available free-of-charge on the internet. As previously indicated, I/B/E/S is not a free service. These data were collected on October 3, 2011. Of the twenty-eight companies, only three (Avista, IDACORP, and MGE) have the same growth rate forecast from the three services. In addition, only six of the companies have the same growth rate forecasts from Yahoo and Reuters, both of which have Thompson Reuters as the source of projected long-term earnings growth rate forecasts.

Q. BASED ON THIS DISCUSSION, WHAT MEASURE OF ANALYSTS' LONG-TERM EPS GROWTH RATE FORECASTS ARE YOU USING?

A. I am using the average of three services published on the internet – Yahoo, Zacks, and Reuters – as the measure of analysts' projected long-term EPS growth rate forecast.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE GROUP AS PROVIDED IN THE *VALUE LINE INVESTMENT SURVEY.*

A. Historic growth rates for the companies in the Electric Proxy Group, as published in the *Value Line Investment Survey*, are provided on page 3 of Exhibit JRW-10. Due to the presence of outliers, I once again use the medians in the analysis. The historical growth measures in EPS, DPS, and BVPS for the Electric Proxy Group, as measured by the medians, range from -0.5% to 7.0%, with an average of 3.4%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUP.

A. *Value Line's* projections of EPS, DPS and BVPS growth for the companies in the Electric Proxy Group are shown on page 4 of Exhibit JRW-10. As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the Electric Proxy Group, the central tendency measure ranges from 3.5% to 5.5%, with an average of 4.4%.

Also provided on page 4 of Exhibit JRW-10 are the sustainable or prospective internal growth rates for the proxy group as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable or internal growth is significant and a primary driver of long-run earnings growth. For the Electric Proxy Group, the average prospective sustainable growth rate is 4.2%.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUP AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters publish Wall Street analysts' five-year EPS growth rate forecasts for the companies in the proxy group. These forecasts are provided for the companies in the Electric Proxy Group on page 5 of Exhibit JRW-10. The medians of the analysts' projected EPS growth rates for the Electric Group is 5.1%.[8]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUP.

A. The summary DCF growth rate indicators for the Electric Proxy Group are shown on page 6 of Exhibit JRW-10. The average of the growth rate indicators for the Electric Proxy Group is 4.3%. The average *Value Line*'s projected growth rates in EPS, DPS, and BVPS is 4.4% and *Value Line*'s sustainable growth rate is 4.2 %. The average of analysts' projected EPS growth rates is 5.1%. The average of the projected and prospective growth rate indicators for the Group is 4.6%. Given these results, and giving more weight to the projections, an expected DCF growth rate in the 4.5% to 5.0% is reasonable. I will use the midpoint of this range, 4.75%, as my DCF growth rate for the Electric Proxy Group.

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[8] Since there appears to be overlap in analyst coverage between the three services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

Q. BASED ON THE ABOVE ANALYSIS, WHAT IS YOUR INDICATED COMMON EQUITY COST RATE FOR THE DCF MODEL?

A. My DCF-derived equity cost rates for the group is:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

DCF Equity Cost Rates

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**4.45%**	**1.02375**	**4.75%**	**9.3%**

These results are summarized on page 1 of Exhibit JRW-10.

C. <u>CAPM Results</u>

Q. PLEASE DISCUSS THE CAPM.

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), and is illustrated as follows:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk or unsystematic risk and (2) market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the "market" refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: (1) the risk-free rate of interest (R_f), (2) the beta (ß), and (3) the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium ($E(R_m) - (R_f)$). I discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-11.

A. Exhibit JRW-11 provides the summary results for my CAPM study. Page 1 shows the summary of the results, and pages 2-11 contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. The yields on 30-year Treasury bonds have varied considerably over the six months. These yields have been in the 3.0% to 4.5% range over the last six months. As of the beginning this month, the rate on 30-year U.S. Treasury Bonds was about 3.0%. Given the recent range of yields, and recognizing the recent decline in Treasury yields, I use 4.0%, as the risk-free rate, or R_f, in my CAPM.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-11, the slope of the regression line is the stock's beta. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher beta and greater than average market risk. A less steep line indicates a lower beta and less market risk.

Numerous online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which the beta is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the Electric Proxy Group, I use the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-11, the median beta for the companies in the Electric Proxy Group is 0.70.

Q. PLEASE DISCUSS THE ALTERNATIVE VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium - $(E(R_m) - R_f)$ - is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 ($E(R_m)$) minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. Page 4 of Exhibit JRW-11 highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson Approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5% to 7% above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) *ex post* returns are not the same as *ex ante* expectations, (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse, and (3) market conditions can change such that *ex post* historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies.[9] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[10]

In addition, there are a number of surveys of financial professionals regarding the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs which includes questions regarding their views on the current expected returns on stocks and

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[9] The problems with using *ex post* historical returns as measures of *ex ante* expectations will be discussed at length later in my testimony.

[10] R. Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).

bonds. Usually over 500 CFOs participate in the survey.[11] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters which is published as the *Survey of Professional Forecasters.*[12] This survey of professional economists has been published for almost 50 years. In addition, Pablo Fernandez conducts occasional surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.

Q. PLEASE PROVIDE A SUMMARY OF THE EQUITY RISK PREMIUM STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the equity risk premium.[13] Derrig and Orr's study evaluated the various approaches to estimating equity risk premiums as well as the issues with the alternative approaches and summarized the findings of the published research on the equity risk premium. Fernandez examined four alternative measures of the equity risk premium – historical, expected, required, and implied. He also reviewed the major studies of the equity risk premium and presented the summary equity risk premium results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the equity risk summary.

[11] *See* www.cfosurvey.org.

[12] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* (February 11, 2011). The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[13] *See* Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

Page 5 of Exhibit JRW-11 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the equity risk premium. In developing page 5 of Exhibit JRW-11, I have categorized the studies as discussed on page 4 of Exhibit JRW-11. I have also included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed. The Building Blocks approach is a hybrid approach employing elements of both historic and *ex ante* models.

Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

A. Ibbotson and Chen (2003) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[14] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and price-earnings ("P/E") ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation ("CPI"), dividend yield ("D/P"), real earnings growth ("RG"), repricing gains ("PEGAIN") and return interaction/reinvestment ("INT").[15] This is shown on page 7 of Exhibit JRW-11. The first column breaks the 1926-2000 geometric mean stock return of

[14] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, (January 2003).

[15] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

10.7% into the different return components demanded by investors: the historical U.S. Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph on page 7 of Exhibit JRW-11 shows current inputs to estimate an ex ante expected market return. These inputs include the following:

<u>CPI</u> – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. Long term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of gross domestic product ("GDP") growth, inflation, and market returns. In the first quarter 2011 survey, published on February 11, 2011, the average long-term (10-year) expected inflation rate as measured by the CPI was 2.30% (see Panel A of page 8 of Exhibit JRW-11).

The University of Michigan's Survey Research Center surveys consumers on their short-term (one-year) inflation expectations on a monthly basis. As shown on page 9 of Exhibit JRW-11, the current short-term expected inflation rate is 3.5%.

As a measure of expected inflation, I will use the average of the long-term (2.3%) and short-term (3.5%) inflation rate measures, or 2.8%.

D/P – As shown on page 10 of Exhibit JRW-11, the dividend yield on the S&P 500 has fluctuated from 1.0% to almost 3.5% over the past decade. Ibbotson and Chen (2003) report that the long-term average dividend yield of the S&P 500 is 4.3%. Currently, the S&P 500 dividend yield is 2.4%. I will use this figure in my ex ante risk premium analysis.

RG – To measure expected real growth in earnings, I use the historical real earnings growth rate of the S&P 500 and the expected real GDP growth rate. The S&P 500 was created in 1960 and includes 500 companies which come from ten different sectors of the economy. On page 11 of Exhibit JRW-11, real EPS growth is computed using the CPI as a measure of inflation. The real growth figure over 1960-2010 period for the S&P 500 is 2.6%.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of U.S. GDP.[16] Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 2.9% (see Panel B of page 8 of Exhibit JRW-11).

Given these results, I will use 2.75%, for real earnings growth.

PEGAIN – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The P/E ratios for the S&P 500 over the past 25 years are shown on page 10 of Exhibit JRW-11. The run-up and eventual peak in P/Es in the year 2000 is very evident in the chart. The average P/E declined until late 2006, and then increased to higher high levels, primarily due to the

[16]Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

decline in EPS as a result of the financial crisis and the recession. The current average P/E for the S&P 500 is approximately 13.0, which is in line with the historic average. Since the current figure is near the historic average, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return.

Q. GIVEN THIS DISCUSSION, WHAT IS THE EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS METHODOLOGY"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" set forth on page 7 of Exhibit JRW-11. As shown, my expected market return of 7.95% is composed of 2.8% expected inflation, 2.4% dividend yield, and 2.75% real earnings growth rate.

Q. IS AN EXPECTED MARKET RETURN OF 7.95% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter 2011 *Survey of Financial Forecasters*, published on February 11, 2011 by the Federal Reserve Bank of Philadelphia, the mean long-term expected return on the S&P 500 was 7.37% (see Panel D of page 8 of Exhibit JRW-11).

Q. IS AN EXPECTED MARKET RETURN OF 7.95% CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOs)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct a quarterly survey of corporate CFOs. The survey is a joint project of Duke University and *CFO*

Magazine. In the September 2011 survey, the mean expected return on the S&P 500 over the next ten years was 6.5%.[17]

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS THE EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. The current 30-year U.S. Treasury yield is approximately 3.00%. This ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 7.95% - 3.0% = 4.95%

Q. HOW ARE YOU USING THIS EQUITY RISK PREMIUM ESTIMATE IN YOUR CAPM EQUITY COST RATE STUDY?

A. This is only one estimate of the equity risk premium. As shown on page 5 of Exhibit JRW-11, I am also using the results of over thirty other studies and surveys to determine an equity risk premium for my CAPM.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-11.

A. Page 5 of Exhibit JRW-11 provides a summary of the results of the equity risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* equity risk premium studies, (3) equity risk premium surveys of CFOs, Financial Forecasters, analysts, companies and

[17] The survey results are available at www.cfosurvey.org.

academics, and (4) the Building Block approaches to the equity risk premium. There are results reported for over thirty studies, and the median equity risk premium is 5.03%.

Q. PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS?

A. The studies cited on page 5 of Exhibit JRW-11 include all equity risk premium studies and surveys I could identify that were published over the past decade and that provided an equity risk premium estimate. Most of these studies were published prior to the financial crisis of the past two years. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so they were not estimating an equity risk premium as of a point in time (e.g., the year 2001). To assess the effect of the earlier studies on the equity risk premium, on page 6 of Exhibit JRW-11 I have reconstructed page 5 of Exhibit JRW-11, but I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 5.10%.

Q. GIVEN THESE RESULTS, WHAT EQUITY RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. I use the median equity risk premium for the 2010-11 studies and surveys, which is 5.10%.

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CFOS AND FINANCIAL FORECASTERS?

A. Yes. My risk premium is below historic averages and therefore is consistent with surveys of CFOs and financial forecasters. In the September 2011 CFO survey conducted by *CFO Magazine* and Duke University, the expected 10-year equity risk premium was 4.2%. In addition, the financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on Panels D and E of page 8 of Exhibit JRW-11, the mean long-term expected stock and bond returns were 7.37% and 4.50%, respectively. This provides an *ex ante* equity risk premium of 2.87%.

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF FINANCIAL ANALYSTS AND COMPANIES?

A. Yes. Pablo Fernandez recently published the results of a 2011 survey of financial analysts and companies. This survey included over 6,000 responses. The median equity risk premium employed by both U.S. analysts and companies was 5.0% and 5.2%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. It published a study entitled "The Real Cost of Equity" in which the McKinsey authors developed an *ex ante* equity risk premium for the U.S. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[18]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy group are provided below:

$$K = (R_f) + \beta * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	**4.0%**	**0.70**	**5.10%**	**7.6%**

These results are summarized on page 1 of Exhibit JRW-11.

VI. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the proxy group of electric utility companies re indicated below:

	DCF	CAPM
Electric Proxy Group	**9.3%**	**7.6%**

[18] Marc H. Goedhart, *et al.*, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUP?

A. These results indicate that the appropriate equity cost rate for Gulf Power is in the 7.6% to 9.3% range. However, since I give greater weight to the results of the DCF model, I believe that the appropriate equity cost rate for Gulf Power is 9.25%.

Q. PLEASE INDICATE WHY A 9.25% RETURN IS APPROPRIATE FOR GULF POWER AT THIS TIME.

A. There are several reasons why 9.25% ROE is an appropriate for the Company in this case. First, as shown on Exhibit JRW-8, the electric utility industry is among the lowest risk industries as measured by beta. As such, the cost of equity capital for the industry is among the lowest in the U.S. according to the CAPM. Second, as shown in Exhibit JRW-3, capital costs for utilities, as indicated by long-term bond yields, have declined to their pre-financial crisis levels. Third, while the financial markets have recovered significantly in the past year, the economy has not. The economic times are still viewed as being difficult, with nearly nine percent unemployment. As a result, interest rates and inflation are at relatively low levels, and hence the expected returns on financial assets – from savings accounts to Treasury bills to common stocks – are low. Therefore, in my opinion, a 9.25% return is appropriate for Gulf Power.

VII. CRITIQUE OF GULF POWER'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE DR. VANDER WEIDE'S RATE OF RETURN RECOMMENDATION FOR GULF POWER.

A. Gulf Power witness Mr. Richard J. McMillan provides the Company's proposed capital structure and long-term debt cost rate, and Dr. James H. Vander Weide recommends a common equity cost rate for Gulf Power. Gulf Power's rate of return recommendation is summarized on page 1 of Exhibit JRW-12. Gulf Power's recommended capital structure includes 1.30% short-term debt, 47.83% long-term debt, 5.31% preferred stock, and 46.87% common equity. Gulf Power uses short-term and long-term debt cost rates of 2.12% and 5.45%, a preferred stock cost rate of 6.65% and an equity cost rate of 11.7%.

Q. WHAT ISSUES DO YOU HAVE WITH THE COMPANY'S COST OF CAPITAL POSITION?

A. The primary areas of disagreement in measuring Gulf Power' cost of capital are: (1) the appropriate debt and preferred stock cost rates for Gulf Power; (2) the dividend yield in the quarterly DCF model; (3) the exclusive use of the projected growth rates of Wall Street analysts to measure expected DCF growth; (4) the base interest rate as well as the market or equity risk premium in the RP and CAPM approaches; (5) unwarranted flotation cost adjustments to his equity cost rate results; and (6) an erroneous leverage adjustment based on the market value capital structures of his proxy group. The debt and preferred stock cost rate issues were discussed previously. The other issues are addressed below.

Q. PLEASE REVIEW DR. VANDER WEIDE'S EQUITY COST RATE APPROACHES.

A. Dr. Vander Weide uses an electric utility proxy group and employs DCF, CAPM, and RP equity cost rate approaches. Dr. Vander Weide's equity cost rate estimates for

Gulf Power are summarized in the in Panel A of Exhibit JRW-13. Based on these figures, he concludes that the appropriate equity cost rate for the Company is 11.7%.

Q. PLEASE DISCUSS YOUR ISSUES WITH DR. VANDER WEIDE'S RECOMMENDED EQUITY COST RATE.

A. Dr. Vander Weide's requested return on common equity is too high, primarily due to: (A) the use of a quarterly DCF dividend yield adjustment in his DCF approach; (B) an inflated growth rate in his DCF approach; (C) excessive equity risk premiums in his RP and CAPM approaches; (D) unwarranted flotation cost adjustments to his equity cost rate results; and (E) an erroneous leverage adjustment based on the market value capital structures of his proxy group. The flotation cost and leverage adjustment are discussed later in the testimony. The individual equity cost rate approaches are reviewed below.

A. <u>DCF Approach</u>

Q. PLEASE SUMMARIZE DR. VANDER WEIDE'S DCF ESTIMATES.

A. On pages 20-30 of his testimony and his Exhibit No. ___(JVW-1), Schedule 1, Dr. Vander Weide develops an equity cost rate by applying a DCF model to his group of electric utility companies. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. Dr. Vander Weide makes adjustments to the dividend yield to reflect the quarterly payment of dividends. Dr. Vander Weide uses one measure of DCF expected growth - the projected EPS growth rate forecasts from Wall Street analysts as provided by I/B/E/S. Dr. Vander Weide's DCF results are provided in Panel B of Exhibit JRW-13. Based on these figures, Dr. Vander Weide claims that the DCF equity cost rate for the Vander Weide Proxy Group is 10.7%.

Q. PLEASE DISCUSS THE ADJUSTMENT TO THE DIVIDEND YIELD TO REFLECT THE QUARTERLY PAYMENT OF DIVIDENDS.

A. In Exhibit___(JVW-2), Schedule 2, Dr. Vander Weide discusses his quarterly DCF model. Dr. Vander Weide's approach compounds the quarterly dividend payment over the year to compute the dividend yield. This compounding process results in an overstated dividend yield.

There are several issues with the quarterly adjustment process. First, as discussed earlier in my testimony, the appropriate dividend yield adjustment for growth in the DCF model is the expected dividend for the next quarter multiplied by four. The quarterly adjustment procedure is inconsistent with this approach. The quarterly model includes an adjustment to reflect the time value of money. Each quarterly dividend is compounded to the end of the year using the long-term growth rate as the compounding factor. As such, this approach presumes that investors require additional compensation during the coming year because their dividends are paid out quarterly instead of being paid all in a lump sum. The error in this logic and approach is that the investor receives the money from each quarterly dividend and has the option to reinvest it as he or she chooses. This reinvestment generates its own compounding, but it is outside of the dividend payments of the issuing company. Dr. Vander Weide's approach serves to duplicate this compounding process, thereby inflating the return to the investor.

Finally, as previously discussed, the appropriate growth rate adjustment to the dividend yield in the DCF model is complicated because companies change their quarterly dividend payments at different times during the year. This means that it is not appropriate to make a full-year adjustment to the dividend yield. Therefore, I have adjusted the dividend yield for the Electric Proxy Group by 1/2 the expected growth rate. This is consistent with the approach used by the Federal Energy Regulatory Commission.[19]

Q. PLEASE CRITIQUE DR. VANDER WEIDE'S DCF GROWTH RATE MEASURES.

A. Dr. Vander Weide uses the projected EPS growth rate forecasts of Wall Street analysts as compiled by I/B/E/S in estimating as his DCF growth rate. His market-value weighted average for the group is 6.0%.

Q. PLEASE DISCUSS THE PRIMARY ERROR IN DR. VANDER WEIDE'S DCF GROWTH RATE ANALYSIS.

A. The primary issue is that Dr. Vander Weide relied exclusively on the long-term EPS growth rate forecasts of Wall Street analysts in developing a DCF growth rate. This is an error. These growth rate forecasts are overly optimistic and upwardly biased. The results of the research on Wall Street analysts' EPS growth rate forecasts are unambiguous on this issue.

Q. PLEASE REVIEW THE ACADEMIC RESEARCH ON THE ACCURACY OF ANALYSTS' NEAR-TERM EPS ESTIMATES AND LONG-TERM EPS GROWTH RATE FORECASTS.

A. There is a long history of studies that evaluate how well analysts forecast near-term EPS estimates and long-term EPS growth rates. Most of the early studies evaluated the

[19] Opinion No. 414-A, *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶61,084 (1998) .

accuracy of earnings forecasts for the next quarter or the next year. These studies demonstrate that analysts make overly optimistic EPS earnings forecasts (Stickel (1990); Brown (1997); Chopra (1998)).[20] Harris (1999) published the first study examining the accuracy of long-term EPS growth rate forecasts.[21] He evaluated the accuracy of analysts' long-term EPS forecasts over the 1982-1997 time period. He concluded the following: (1) the accuracy of analysts' long-term EPS forecasts is very low; (2) a superior long-run method to forecast long-term EPS growth is to assume that all companies will have an earnings growth rate equal to historic GDP growth; and (3) analysts' long-term EPS forecasts are significantly upwardly biased, with forecasted earnings growth exceeding actual earnings growth by seven percent per annum. Subsequent studies by DeChow, P., A. Hutton, and R. Sloan (2000), and Chan, Karceski, and Lakonishok (2003) also conclude that analysts' long-term EPS growth rate forecasts are overly optimistic and upwardly biased.[22]

More recent studies have shown that the optimistic bias tends to be larger for longer-term forecasts and smaller for forecasts made nearer to the EPS announcement date. Richardson, Teoh, and Wysocki (2004) report that the upward bias in earnings growth rates declines in the quarters leading up to the earnings announcement date.[23] They call this result the "walk-down to beatable analyst forecasts." They hypothesize that the walk-down might be driven by the "earning-guidance game," in which

[20] S. Stickel, "Predicting Individual Analyst Earnings Forecasts," *Journal of Accounting Research*, Vol. 28, 409-417, 1990. Brown, L.D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal*, Vol. 53, 81-88, 1997, and Chopra, V.K., "Why So Much Error in Analysts' Earnings Forecasts?" *Financial Analysts Journal*, Vol. 54, 30-37 (1998).
[21] R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999).
[22] P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research (2000)* and K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643–684, (2003).
[23] S. Richardson, S. Teoh, and P. Wysocki, "The Walk-Down to Beatable Analyst Forecasts: The Role of Equity Issuance and Insider Trading Incentives," *Contemporary Accounting Research*, pp. 885–924, (2004).

analysts give optimistic forecasts at the start of a fiscal year, then revise their estimates downwards until the firm can beat the forecasts at the earnings announcement date.

In sum, there have been many studies of analysts' earnings forecasts. The studies conclude (almost unanimously) that analysts' earnings forecasts of short-term earnings estimates and long-term earnings growth rates are overly optimistic. In terms of analysts' projections of long-term earnings growth, all previous studies have come to this conclusion.

Q. PLEASE DISCUSS YOUR STUDY OF THE ACCURACY OF ANALYSTS' LONG-TERM EARNINGS GROWTH RATES.

A. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In Panel A of page 1 of Exhibit JRW-14, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate for the past twenty years.

The following example shows how the results can be interpreted. For the 3-5 year period prior to the first quarter of 1999, analysts had projected an EPS growth rate of 15.13%, but companies generated an average annual EPS growth rate over the 3-5 years of only 9.37%. This projected EPS growth rate figure represented the average projected growth rate for over 1,510 companies, with an average of 4.88 analyst forecasts per company. For the entire twenty-year period of the study, for each quarter there were, on average, 5.6 analysts' EPS projections for 1,281 companies. Overall, my findings indicate that forecast errors for long-term estimates are predominantly positive, which indicates an upward bias in growth rate estimates. The mean and median forecast errors over the observation period are 143.06% and 75.08%, respectively. The forecasting errors are negative for only eleven of the eighty quarterly time periods: five consecutive quarters starting at the end of 1995, and six consecutive quarters starting in 2006. As shown in Panel A of page 1 of Exhibit JRW-14, the quarters with negative forecast errors were for the 3-5 year periods following earnings declines associated with the 1991 and 2001 economic recessions in the U.S. Thus, there is evidence of a persistent upward bias in long-term EPS growth forecasts.

The average 3-5 year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1988 to 2008 are shown in Panel B of page 1 of Exhibit JRW-14. In this graph, no comparison to actual EPS growth rates is made, and hence, there is no follow-up period. Therefore, since companies are not lost from the sample due to a lack of follow-up EPS data, these results are for a larger sample of firms. Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until 1995 and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted EPS growth has since declined to the 15.0% range.

Q. HAVE THE MARKETS OBSERVED THE UPWARD BIAS IN ANALYSTS' GROWTH RATE FORECASTS THAT YOU OBSERVE?

A. Yes. Page 2 of Exhibit JRW-14 provides an article published in the *Wall Street Journal*, dated March 21, 2008, that discusses the upward bias in analysts' EPS growth rate forecasts.[24] In addition, a recent *Bloomberg Businessweek* article also highlighted the upward bias in analysts' EPS forecasts, citing a study by McKinsey Associates. This article is provided on pages 3 and 4 of Exhibit JRW-14. The article concludes with the following:[25]

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Q. PLEASE ADDRESS THE COMPARATIVE ACCURACY OF ANALYSTS' EPS FORECASTS AND HISTORIC AND TIME-SERIES ESTIMATES OF EPS GROWTH.

A. As highlighted by the classic study by Brown and Rozeff (1976) and the other studies that followed, analysts' forecasts of quarterly earnings estimates are superior to the estimates derived from historic and time-series analyses.[26] This is often attributed to the information and timing advantage that analysts have over historic and time-series analyses. However, more recently Bradshaw, Drake, Myers, and Myers (2009) discovered that time-series estimates of annual earnings are more accurate over longer horizons than analysts' forecasts of earnings. As the authors state, "These findings suggest an incomplete and misleading generalization about the superiority of analysts' forecasts over even simple time-series-based earnings forecasts."[27]

With respect to long-term earnings growth, analysts' forecasts of long-term growth have not been found to be superior to other historic growth rate measures. Harris

[24] Andrew Edwards, "Study Suggests Bias in Analysts' Rosy Forecasts," *Wall Street Journal* (March 21, 2008), p. C6.
[25] Roben Farzad, 'For Analysts, Things are Always Looking Up,' *Bloomberg Businessweek* (June 14, 2010), pp. 39-40.
[26] L. Brown and M. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings," *The Journal of Finance* 33 (1): pp. 1-16 (1976).
[27] M. Bradshaw, M. Drake, J. Myers, and L. Myers, "A Re-examination of Analysts' Superiority Over Time-Series Forecasts," Workings paper, (1999), http://ssrn.com/abstract=1528987.

(1999) concluded that historic GDP growth was superior to analysts' forecasts for long run earnings growth. These results are supported by empirical results of Chan, Karceski, and Lakonishok (2003).

Q. WHAT IMPACT HAVE NEW STOCK MARKET AND REGULATORY DEVELOPMENTS HAD ON ANALYSTS' EPS GROWTH RATE FORECASTS?

A. Analysts' EPS growth rate forecasts have subsided somewhat since the stock market peak of 2000. Two regulatory developments over the past decade have potentially impacted analysts' EPS growth rate estimates. First, Regulation Fair Disclosure ("Reg FD") was introduced by the Securities and Exchange Commission ("SEC") in October of 2000. Reg FD prohibits private communication between analysts and management so as to level the information playing field in the markets. With Reg FD, analysts are less dependent on gaining access to management to obtain information and therefore, are not as likely to make optimistic forecasts to gain access to management. Second, the conflict of interest within investment firms with investment banking and analyst operations was addressed in the Global Analysts Research Settlements ("GARS"). GARS, as agreed upon on April 23, 2003, between the SEC, NASD, NYSE and ten of the largest U.S. investment firms, includes a number of regulations that were introduced to prevent investment bankers from pressuring analysts to provide favorable projections.

The impact of these regulatory developments on the accuracy of short-term EPS estimates was addressed in a recent study by Hovakimian and Saenyasiri (2009).[28] They investigate analysts' forecasts of annual earnings for the following time periods: (1) the time prior to Reg FD (1984-2000); (2) the time period after Reg

[28] A. Hovakimian and E. Saenyasiri, "Conflicts of Interest and Analysts Behavior: Evidence from Recent Changes in Regulation," *Financial Analysts* Journal (July-August, 2010), pp. 96-107.

FD but prior to GARS (2000-2002);[29] and (3) the time period after GARS (2002-2006). For the pre-Reg FD period, Hovakimian and Saenyasiri find that analysts generally made overly optimistic forecasts of annual earnings. The forecast bias was higher for early forecasts and steadily declined in the months leading up to the earnings announcement. The results are similar for the time period after Reg FD but prior to GARS. However, the bias was lower in the later forecasts (the forecasts made just prior to the announcement). For the time period after GARS, the average forecasts declined significantly, but a positive bias remains. In sum, Hovakimian and Saenyasiri find that: (1) analysts make overly optimistic short-term forecasts of annual earnings; (2) Reg FD had no effect on this bias; and (3) GARS did result in a significant reduction in the bias, but analysts' short-term forecasts of annual earnings still have a small positive bias.

Whereas Hovakimian and Saenyasiri evaluated the impact of regulations on analysts' short-term EPS estimates, there is little research on the impact of Reg FD and GARS on the long-term EPS forecasts of Wall Street analysts. My study with Patrick Cusatis did find that the long-term EPS growth rate forecasts of analysts did not decline significantly and have continued to be overly-optimistic in the post Reg FD and GARS period.[30] Analysts' long-term EPS growth rate forecasts before and after GARS are about two times the level of historic GDP growth. These observations are supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the

[29] Whereas the GARS settlement was signed in 2003, rules addressing analysts' conflict of interest by separating the research and investment banking activities of analysts went into effect with the passage of NYSE and NASD rules in July of 2002.

[30] P. Cusatis and J. R. Woolridge, "The Accuracy of Analysts' Long-Term EPS Growth Rate Forecasts," Working Paper, (July 2008).

continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. "You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed. Research remains rosy and many believe it always will.[31]

Q. HOW DO THESE OBSERVATIONS COMPARE WITH THE FINDINGS OF A RECENT MCKINSEY STUDY ON THE IMPACT OF THESE REGULATIONS ON THE ACCURACY OF ANALYSTS' EPS GROWTH RATE FORECASTS?

A. McKinsey recently published a study entitled "Equity Analysts: Still too Bullish" in which they reported on a study of the accuracy on analysts long-term EPS growth rate forecasts. They concluded that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic.

They made the following observation (emphasis added):[32]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to

[31] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation," *Wall Street Journal*, p. C1, (January 27, 2003).
[32] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

> reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. <u>Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.</u> (Emphasis added.)

Q. ARE YOUR OBSERVATIONS REGARDING THE UPWARD BASIS OF ANALYSTS' EPS GROWTH RATE FORECASTS APPLICABLE TO UTILITY COMPANIES?

A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for utility companies, I conducted a study similar to the one described above using a group of electric utility companies. The results are shown on Panels A and B of page 5 of Exhibit JRW-14. The projected EPS growth rates for electric utilities have been in the 4% to 6% range over the last twenty years, with the recent figures approximately 5%. As shown, the achieved EPS growth rates have been volatile and on average, below the projected growth rates. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 4.59% and 2.90%, respectively.

Overall, the upward bias in EPS growth rate projections for electric utility companies is not as pronounced as it is for all companies. Nonetheless, the results here are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly-biased for utility companies.

Q. WHAT ABOUT *VALUE LINE*'S GROWTH RATE FORECASTS?

A. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in Panel A of Page 6 of Exhibit JRW-14. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 1,996 firms. The average projected EPS growth rate was 14.45%. This is high given that the average historical EPS growth rate in the U.S. is about 7%. A major factor seems to be that *Value Line* only predicts negative EPS growth for 56 companies. This is less than three percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

To put this figure in perspective, I screened the *Value Line* companies to see what percent of companies covered by *Value Line* had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 2,147 companies. The results are shown in Panel B of page 6 of Exhibit JRW-14 and indicate that the average 5-year historic growth rate was 8.38%, and *Value Line* reported negative historic growth for 654 firms which represents 30.4% of these companies.

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that the analysts at *Value Line* are similar to their Wall Street brethren in that they are reluctant to forecast negative earnings growth.

Q. DR. VANDER WEIDE HAS DEFENDED THE USE OF ANALYSTS' EPS FORECASTS IN HIS DCF MODEL BY CITING A STUDY HE PUBLISHED WITH DR. WILLARD CARLETON. PLEASE DISCUSS DR. VANDER WEIDE'S STUDY.

A. Dr. Vander Weide cites the study on page 25 of his testimony. In the study, Dr. Vander Weide performs a linear regression of a company's stock price to earnings ratio (P/E) on the dividend yield payout ratio (D/E), alternative measures of growth (g), and four measures of risk (beta, covariance, r-squared, and the standard deviation of analysts' growth rate projections). He performed the study for three one-year periods – 1981-1982, and 1983 – and used a sample of approximately 65 companies. His results indicated that regressions measuring growth as analysts' forecasted EPS growth were more statistically significant that those using various historic measures of growth. Consequently, he concluded that analysts' growth rates are superior measures of expected growth.

Q. PLEASE CRITIQUE DR. VANDER WEIDE'S STUDY.

A. Before highlighting the errors in the study, it is important to note that the study was published twenty years ago, used a sample of only sixty-five companies, and evaluated a three-year time period (1981-83) that was over twenty-five years ago. Since that time, many more exhaustive studies have been performed using significantly larger data bases and, from these studies, much has been learned about Wall Street analysts and their stock recommendations and earnings forecasts. Nonetheless, there are several errors that invalidate the results of the study.

Q. PLEASE DESCRIBE THE ERRORS IN DR. VANDER WEIDE'S STUDY.

A. The primary error in the study is that his regression model is misspecified. As a result, he cannot conclude whether one growth rate measure is better than the other. The misspecification results from the fact that Dr. Vander Weide did not actually employ a modified version of the DCF model. Instead, he used a "linear approximation." He used the approximation so that he did not have to measure k, investors' required return, directly; instead, he used some proxy variables for risk. The error in this approach is there can be an interaction between growth (g) and investors' required return (k) which could lead him to conclude that one growth rate measure is superior to others. Furthermore, due to this problem, analysts' EPS forecasts could be upwardly biased and still appear to provide better measures of expected growth.

There are other errors in the study as well that further invalidate the results. Dr. Vander Weide does not use both historic and analysts' projections growth rate measures in the same regression to assess if both historic and forecasts should be used together to measure expected growth. In addition, he did not perform any tests to determine if the difference between historic and projected growth measures is statistically significant. Without such tests, he cannot make any conclusions about the superiority of one measure versus the other.

B. <u>Risk Premium ("RP") Approach</u>

Q. PLEASE REVIEW DR. VANDER WEIDE'S RP ANALYSIS.

A. On pages 30-38 of his testimony and in Exhibit No. ___(JVW-1), Schedules 1-4, Dr. Vander Weide develops an equity cost rate using expected (ex ante) and historical (ex post) RP models. Dr. Vander Weide's RP results are provided in Panels C and D of Exhibit JRW-13. In his ex ante RP approach, Dr. Vander Weide computes an expected stock return by applying the DCF model to the S&P utilities and the S&P 500 and uses the EPS growth rate forecasts of Wall Street analysts as his growth rate. He then subtracts the yield on 'A' rated utility bonds. In his historic RP model, Dr. Vander Weide's computes a historical risk premium as the difference in the arithmetic mean stock and bond returns. The stock returns are computed for different time periods for several different indexes, including S&P and Moody's electric utility indexes as well as the S&P 500. Both his ex ante and ex post RP studies include an adjustment for flotation costs. His ex ante and ex post RP studies provide equity cost rates of 11.0% and 10.8%.

Q. WHAT ARE THE ERRORS IN DR. VANDER WEIDE'S RP ANALYSES?

A. The errors in Dr. Vander Weide's RP equity cost rate approaches include: (1) an inflated base interest rate; (2) excessive risk premiums in both the ex ante and ex post RP studies; and (3) the inclusion of flotation costs. The flotation cost issue is addressed later in the testimony. The other two issues are discussed below.

Q. PLEASE DISCUSS THE BASE YIELD OF DR. VANDER WEIDE'S RISK PREMIUM ANALYSES.

A. The base yield in Dr. Vander Weide's RP analyses is the projected yield on 'A' rated utility bonds. There are two issues with his projected 6.15% 'A' rated utility bond yield. First, the yield is well above current market rates. As shown on Page 2 of Exhibit JRW-3, the current yield on long-term, 'A' rated public utility bonds is about 4.5%. Second, Vander Weide's base yield is erroneous and inflates the required return on equity in two ways. First, long-term bonds are subject to interest rate risk, a risk which does not affect common stockholders since dividend payments (unlike bond interest payments) are not fixed but tend to increase over time. Second, the base yield in Dr. Vander Weide's risk premium study is subject to credit risk since it is not default risk-free like an obligation of the U.S. Treasury. As a result, its yield-to-maturity includes a premium for default risk and therefore is above its expected return. Hence, using such a bond's yield-to-maturity as a base yield results in an overstatement of investors' return expectations.

Q. DR. VANDER WEIDE EMPLOYS A DCF-BASED EX ANTE RISK PREMIUM APPROACH. PLEASE DISCUSS THE ERRORS IN THIS APPROACH.

A. Dr. Vander Weide computes a DCF-based equity risk premium in Exhibit__(JVW-1), Schedule 2. Dr. Vander Weide estimates an expected return using the DCF model and subtracts a concurrent measure of interest rates. The expected return is computed for utilities using the DCF model with analysts' EPS growth rate forecasts for the growth rate. Then Dr. Vander Weide employs 'A' rated utility yields as a measure of interest rates. From the results of his study, he concludes that an appropriate ex ante risk premium is 4.90%.

The primary error in this approach is the DCF-based or ex ante risk premium. This ex ante risk premium uses of the EPS growth rate forecasts of Wall Street analysts as the one and only measure of growth in the DCF model. This issue was previously addressed. In short, as I discuss and demonstrate in Appendix A, analysts' EPS growth rate forecasts are upwardly biased estimates of actual EPS growth for companies in general as well as for electric utilities.

Q. PLEASE REVIEW DR. VANDER WEIDE'S EX POST OR HISTORIC RP STUDY.

A. Dr. Vander Weide performs an ex-post or historical RP study that appears in Exhibit__(JVW-1), Schedules 3 and 4. This study involves an assessment of the historical differences between S&P Public Utility Index and the S&P 500 stock returns stocks and bonds. This change suggests that the equity risk premium has declined.

Q. PLEASE DISCUSS THE PROBLEMS WITH USING HISTORIC STOCK AND BOND RETURNS TO ESTIMATE AN EQUITY RISK PREMIUM.

A. There are a number of flaws in using historic returns over long time periods to estimate expected equity risk premiums. These issues include:

1) Biased historical bond returns

2) Use of the arithmetic versus the geometric mean return

3) The large error in measuring the equity risk premium using historical returns

4) Unattainable and biased historical stock returns

5) Company Survivorship bias

6) The "Peso Problem" - U.S. stock market survivorship bias

These issues will be addressed in order.

1) <u>Biased Historical Bond Returns</u>

Q. HOW ARE HISTORICAL BOND RETURNS BIASED?

A. An essential assumption of these studies is that over long periods of time, investors' expectations are realized. However, the experienced returns of bondholders in the past invalidate this critical assumption. 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.

2) <u>The Arithmetic versus the Geometric Mean Return</u>

Q. PLEASE DISCUSS THE ISSUE RELATING TO THE USE OF THE ARITHMETIC VERSUS THE GEOMETRIC MEAN RETURNS IN THE

and public utility bond returns over various time periods between the years 1937-2010. From the results of his study, he concludes that an appropriate risk premium is 4.35%.

Q. PLEASE ADDRESS THE ISSUES INVOLVED IN USING HISTORICAL STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. Using the historical relationship between stock and bond returns to measure an ex ante equity risk premium is erroneous and, especially in this case, overstates the true market equity risk premium. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. Using historical returns to measure the ex ante equity risk premium ignores current market conditions and masks the change in the risk and return relationship between stocks and bonds. This change suggests that the equity risk premium has declined.

Q. PLEASE ADDRESS THE ISSUES INVOLVED IN USING HISTORICAL STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. Using the historical relationship between stock and bond returns to measure an ex ante equity risk premium is erroneous and, especially in this case, overstates the true market equity risk premium. The equity risk premium is based on expectations of the future and when past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. Using historical returns to measure the ex ante equity risk premium ignores current market conditions and masks the change in the risk and return relationship between

IBBOTSON METHODOLOGY.

A. The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[33] Since Dr. Vander Weide's historic study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric mean and not the arithmetic mean.

Q. **PLEASE PROVIDE AN EXAMPLE DEMONSTRATING THE PROBLEM WITH USING THE ARITHMETIC MEAN RETURN.**

A. To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is selling for $100 today, increases to $200 in one year, and then falls back to $100 in two years.

The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic

[33] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal*, pp. 38-47, (January-February, 1985).

mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. As further evidence of the appropriate mean return measure, the SEC requires equity mutual funds to report historic return performance using geometric mean and not arithmetic mean returns.[34] Therefore, the historic arithmetic mean return measures are biased and should be disregarded.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE DEBATE OVER THE USE OF THE ARITHMETIC VERSUS THE GEOMETRIC MEAN RETURN IN DEVELOPING AN EXPECTED MARKET RISK PREMIUM.

A. In measuring historic returns to develop an expected equity risk premium, finance texts will often recommend the use of an arithmetic mean return as a measure of central tendency. A common justification for using the arithmetic mean return is that since annual stock returns are not serially correlated, the best measure of a return for next year is the arithmetic mean of past returns. On the other hand, Damodaran suggests that such an estimate is not appropriate in estimating an equity risk premium:[35]

> "There are, however, strong arguments that can be made for the use of geometric averages. First, empirical studies seem to indicate that returns on stocks are negatively correlated over long periods of time. Consequently, the arithmetic average return is

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[34] SEC, Form N-1A.

[35] Aswath. Damodaran, "A New "Risky" World Order: Unstable Risk Premiums - Implications for Practice" NUU Working Paper, 2010, p. 25.

> likely to overstate the premium. Second, while asset pricing models may be single period models, the use of these models to get expected returns over long periods (such as five or ten years) suggests that the estimation period may be much longer than a year. In this context, the argument for geometric average premiums becomes stronger."

3) <u>The Error in Measuring Equity Risk Premiums with Historic Data</u>

Q. PLEASE DISCUSS THE ERROR IN MEASURING THE EQUITY RISK PREMIUM USING HISTORICAL STOCK AND BOND RETURNS.

A. Measuring the equity risk premium using historical stock and bond returns is subject to a substantial forecasting error. For example, the arithmetic mean long-term equity risk premium of approximately 6.5% has a standard deviation of over 20.0%. This may be interpreted in the following way with respect to the historical distribution of the long-term equity risk premium using a standard normal distribution and a 95%, +/- 2 standard deviation confidence interval: We can say, with a 95% degree of confidence, that the true equity risk premium is between -34.7% and +47.7%. As such, the historical equity risk premium is measured with a substantial amount of error.

4) <u>Unattainable and Biased Historic Stock Returns</u>

Q. YOU NOTE THAT HISTORIC STOCK RETURNS ARE BIASED USING THE IBBOTSON METHODOLOGY. PLEASE ELABORATE.

A. Returns developed using Ibbotson's methodology are computed on stock indexes and therefore: (1) cannot be reflective of expectations because these returns are unattainable to investors and (2) produce biased results. This methodology assumes: (1) monthly portfolio rebalancing and (2) reinvestment of interest and dividends. Monthly portfolio rebalancing presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption generates high transaction costs and thereby renders these returns unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[36]

Transaction costs themselves provide another bias in historic versus expected returns. In the past, the observed stock returns were not the realized returns of investors, due to the much higher transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades and the lack of low cost mutual funds like index funds.

5) <u>Company Survivorship Bias</u>

Q. HOW DOES COMPANY SURVIVORSHIP BIAS AFFECT THE HISTORIC EQUITY RISK PREMIUM?

A. Using historic data to estimate an equity risk premium suffers from company survivorship bias. Company survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform well were dropped from these indexes is not reflected. Therefore, these stock returns are upwardly biased because they only reflect the returns from more successful companies.

[36] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-86, (1983).

6) The "Peso Problem" - U.S. Stock Market Survivorship Bias

Q. WHAT IS THE "PESO PROBLEM," AND HOW DOES IT RELATE TO SURVIVORSHIP BIAS IN U. S. STOCK MARKET RETURNS?

A. The use of historic return data also suffers from the so-called "Peso Problem," which is also known as U.S. stock market survivorship bias. The "peso problem" issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the early 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression and other social, political, and economic events, the U.S. economy survived and did not suffer hyperinflation, invasion and/or the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations. Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the "peso problem" indicates that historic stock returns are overstated as measures of expected returns because the U.S. markets have not experienced the disruptions of other major markets around the world.

Q. DO YOU HAVE ANY OTHER THOUGHTS ON THE USE OF HISTORICAL RETURN DATA TO ESTIMATE AN EQUITY RISK PREMIUM?

A. Yes. Jay Ritter, a Professor of Finance at the University of Florida, identified the use of historical stock and bond return data to estimate a forward-looking equity risk premium as one of the "Biggest Mistakes" taught by the finance profession.[37] His argument is based on the theory behind the equity risk premium, the excessive results produced by historical returns, and the previously-discussed errors such as

[37] Jay Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research* (Summer 2002).

survivorship bias in historical data.

C. **CAPM Approach**

Q. PLEASE DISCUSS DR. VANDER WEIDE'S CAPM.

A. On pages 38-46 of his testimony and in Exhibit No. ___(JVW-1), Schedules 5-8, Dr. Vander Weide develops an equity cost rate using the CAPM and two different market risk premium approaches. Dr. Vander Weide's CAPM results are provided in Panels E and F of Exhibit JRW-13. Dr. Vander Weide estimates equity cost rates of 10.7% using his expected CAPM and 9.20% using his historical CAPM approach. He elects to not recommend the use of the CAPM results due to the notion that the CAPM underestimates the equity cost rate for companies such as utilities that have betas less than 1.0.

Q. WHAT ARE THE ERRORS IN DR. VANDER WEIDE'S CAPM ANALYSIS?

A. There are three flaws with Dr. Vander Weide's CAPM analysis: (1) his risk-free rate of 4.45%; (2) the historic and expected market risk premiums; and (3) the flotation cost adjustment. The flotation cost adjustment is discussed later in the testimony. The other issues are addressed below.

Q. PLEASE DISCUSS DR. VANDER WEIDE'S RISK-FREE RATE OF INTEREST IN HIS CAPM.

A. Dr. Vander Weide uses a risk-free rate of interest of 4.45% in his CAPM. This well in excess of the current yield on long-term Treasury bonds, which is less than 3.0%

Q. PLEASE ADDRESS THE PROBLEMS WITH DR. VANDER WEIDE'S HISTORIC CAPM.

A. Dr. Vander Weide's historical CAPM uses an equity risk premium of 6.7%, which is based on the difference between the arithmetic mean stock and bond income returns over the 1926-2010 period. The errors associated with computing an expected equity risk premium using historical stock and bond returns were addressed at length earlier in my testimony. In short, there is a myriad of empirical problems, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the 'Peso Problem'), the company survivorship bias (only successful companies survive – poor companies do not survive), and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). In addition, in this case, Dr. Vander Weide has compounded the error by using the bond income return and not the actual bond return. By omitting the price change component of the bond return, he has magnified the historic risk premium by not matching the returns on stock with the actual returns on bonds.

Q. PLEASE REVIEW THE ERRORS IN DR. VANDER WEIDE'S EQUITY OR MARKET RISK PREMIUM IN HIS EXPECTED CAPM APPROACH.

A. Dr. Vander Weide develops an expected equity risk premium for his CAPM of 8.85% in Exhibit No. ___(JVW-1), Schedule 8 by applying the DCF model to the S&P 500. Dr. Vander Weide estimates an expected market return of 13.3% using a dividend yield of 2.7% and an expected DCF growth rate of 10.6%. The most significant error with this approach is that the expected DCF growth rate is the projected 5-year EPS growth rate for the companies in the S&P 500 as reported by I/B/E/S. As explained below, this produces an overstated expected market return and equity risk premium.

Q. PLEASE REVIEW DR. VANDER WEIDE'S EQUITY OR MARKET RISK PREMIUM IN HIS CAPM APPROACH.

A. The primary problem with Dr. Vander Weide's CAPM analysis is the size of the market or equity risk premium. Dr. Vander Weide develops an expected market risk premium of 8.85% by: (1) applying the DCF model to the S&P 500 to get an expected market return; and (2) subtracting the risk-free rate of interest. Dr. Vander Weide's estimated market return of 13.3% for the S&P 500 equals the sum of the dividend yield of 2.7% and expected EPS growth rate of 10.6%. The expected EPS growth rate is the average of the expected EPS growth rates from I/B/E/S. The primary error in this approach is his expected DCF growth rate. As previously discussed, the expected EPS growth rates of Wall Street analysts are upwardly biased. Therefore, as explained below, this produces an overstated expected market return and equity risk premium.

Q. BEYOND YOUR PREVIOUS DISCUSSION OF THE UPWARD BIAS IN WALL STREET ANALYSTS' EPS GROWTH RATE FORECASTS, WHAT OTHER EVIDENCE CAN YOU PROVIDE TO DEMONSTRATE THAT DR. VANDER WEIDE'S S&P 500 GROWTH RATE IS EXCESSIVE?

A. A long-term EPS growth rate of 10.6% is not consistent with historic as well as projected economic and earnings growth in the U.S for several reasons: (1) Dr. Vander Weide's projected EPS growth rate of 10.6% is almost double long-term EPS and economic growth, as measured by GDP; (2) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future; and (3) over time, EPS growth tends to lag behind GDP growth.

The long-term economic, earnings, and dividend growth rate in the U.S. has only been in the 5% to 7% range. I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-15, and a summary is given in the table below.

GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.94%**
S&P 500 Stock Price Appreciation	**6.34%**
S&P 500 EPS	**6.81%**
S&P 500 DPS	**5.04%**
Average	**6.28%**

These results indicate that historically the long-run growth rate for GDP, S&P EPS, and S&P DPS in the 5% to 7% range. By comparison, Dr. Vander Weide's long-run growth rate projection of 10.6% is overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of EPS by almost 100% in the future and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-half of his projected growth rates.

Q. DO MORE RECENT DATA SUGGEST THAT THE U.S. ECONOMY GROWTH IS FASTER OR SLOWER THAN THE LONG-TERM DATA?

A. The more recent trends suggest that future economic growth will be lower than the long-term historic GDP growth. The historic GDP growth rates for 10-, 20-, 30-, 40- and 50-years are presented in Panel A of page 2 of Exhibit JRW-15. These figures clearly suggest that GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy. These figures indicate that Dr. Vander Weide's long-term growth EPS growth rate of 10.6% is inflated.

Q. WHAT LEVEL OF GDP GROWTH IS FORECASTED BY ECONOMISTS AND VARIOUS GOVERNMENT AGENCIES?

A. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of page 2 of Exhibit JRW-15. The mean 10-year nominal GDP growth forecast (as of February 2011) by economists in the recent *Survey of Professional Forecasters* is 5.2%. The Energy Information Administration (EIA), in its projections used in preparing *Annual Energy Outlook,* forecasts long-term GDP growth of 4.8% for the period 2009-2035. The Congressional Budget Office, in its forecasts for the period 2010 to 2021, projects a nominal GDP growth rate of 5.6%. As such, projections of nominal GDP growth provide additional evidence that Dr. Vander Weide's long-term EPS growth rate of 10.6% is overstated.

Q. PLEASE HIGHLIGHT THE RECENT RESEARCH ON THE LINK BETWEEN ECONOMIC AND EARNINGS GROWTH AND EQUITY RETURNS.

A. Brad Cornell of the California Institute of Technology recently published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth. He concludes with the following observations:[38]

> "The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms."

Given current inflation in the 2% to 3% range, the results imply nominal expected stock market returns in the 6% to 8% range. As such, Dr. Vander Weide's projected earnings growth rates and implied expected stock market returns are not indicative of the realities of the U.S. economy and stock market.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF DR. VANDER WEIDE'S EQUITY RISK PREMIUMS DERIVED FROM EXPECTED MARKET RETURNS.

A. Dr. Vander Weide's equity risk premium of 8.85% derived from his expected market return of 13.3% is not reflective of the risk premiums used in the real world of finance. Investment banks, analysts, companies, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment, and valuation decisions. I provided the results of over thirty academic studies and recent surveys of these financial professionals. These equity risk premium estimates are in the 4% to 5% range and not in

[38] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February, 2010), p. 63.

the 8%-10% range. On this issue, the opinions of CFOs are especially relevant. CFOs deal with capital markets on an ongoing basis since they must continually assess and evaluate capital costs for their companies. They are well aware of the historical equity risk premium results as published by Ibbotson Associates as well as Wall Street analysts' projections. Nonetheless, the CFOs in the September 2011 *CFO Magazine* – Duke University Survey of almost 500 CFOs shows an expected equity risk premium of 4.2% over the next ten years. In addition, surveys conducted in 2011 by Fernandez indicate that financial analysts and companies are using equity risk premiums of about 5.0%. As such, using these real world equity risk premiums, the appropriate equity cost rate for Gulf Power Company should be in the 8.0% to 9.0% range and not in the 11.0% range.

D. <u>Flotation Costs</u>

Q. PLEASE DISCUSS DR. VANDER WEIDE'S ADJUSTMENT FOR FLOTATION COSTS.

A. Dr. Vander Weide claims that an upward adjustment to the equity cost rate is warranted for flotation costs. This adjustment factor is erroneous for several reasons. First, he has not identified any actual flotation costs for the Company. Therefore, the Company is requesting annual revenues in the form of a higher return on equity for flotation costs that have not been identified. Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. In this case, Dr. Vander Weide justifies a flotation cost adjustment by referring to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.3X actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, electric utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Hence, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the

Company is receiving. The offering price which they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transaction costs, it has not accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in its DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

E. Leverage Adjustment

Q. PLEASE REVIEW DR. VANDER WEIDE'S LEVERAGE ADJUSTMENT.

A. Dr. Vander Weide has added a leverage adjustment of 90 basis points to the estimated equity cost rates that he estimated using the DCF, RP, and CAPM approaches. Dr. Vander Weide claims that this is needed since (1) market values are greater than book values for utilities and (2) the overall rate of return is applied to a book value capitalization in the ratemaking process. This adjustment is unwarranted for the following reasons:

(1) The market value of a firm's equity exceeds the book value of equity when the

firm is expected to earn more on the book value of investment than investors require. This relationship is described very succinctly in the Harvard Business School case study which I quote earlier in my testimony. As such, the reason that market values exceed book values is that the company is earning a return on equity in excess of its cost of equity;

(2) Despite Dr. Vander Weide's contention that this represents a leverage adjustment, there is no change in leverage. There is no need for a leverage adjustment since there is no change in leverage. The Company's financial statements and fixed financial obligations remain the same;

(3) Financial publications and investment firms report capitalizations on a book value and not a market value basis; and

(4) Dr. Vander Weide has presented his leverage adjustment in many rate cases before many regulatory commissions. In response OPC interrogatories, Dr. Vander Weide indicated that he: (1) has testified in over 400 cases before regulatory commissions; and (2) had been recommending the leverage adjustment to his cost of equity since the early 1990s. However, he could not identify any proceeding in which he has testified in which the regulatory commission had adopted his leverage adjustment.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT REGULATORY COMMISSIONS HAVE REJECTED DR. VANDER WEIDE'S LEVERAGE ADJUSTMENT?

A. I believe that Dr. Vander Weide's leverage adjustment has been rejected by regulatory commissions because it increases the ROEs for utilities that have high returns on common equity and decreases the ROEs for utilities that have low returns on common equity.

In the graphs presented in Exhibit JRW-6, I have demonstrated that there is a strong positive relationship between expected returns on common equity and market-to-book ratios for public utilities. Hence, in the context of Dr. Vander Weide's leverage adjustment, this means that: (1) for a utility with a relatively high market-to-book ratio (e.g., 2.5) and ROE (e.g., 12.0%), the leverage adjustment will increase the estimated equity cost rate, while (2) for a utility with a relatively low market-to-book ratio (e.g., 0.5) and ROE (e.g., 5.0%), the leverage adjustment will decrease the estimated equity cost rate. Therefore, the adjustment will result in even higher market-to-book ratios for utilities with relatively high ROEs and even lower market-to-book ratios for utilities with relatively low ROEs.

VIII. PARENT DEBT ADJUSTMENT

Q. PLEASE REVIEW THE COMMISSION'S POLICY REGARDING THE PARENT DEBT ADJUSTMENT TO REDUCE A UTILITY'S INCOME TAX EXPENSE RELATED TO ITS PARENT COMPANY'S DEBT.

A. Rule 25-14.004, F.A.C., provides that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." Further, Rule 25-14.004(3), F.A.C., states that "it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure."

In several recent cases, the Commission has found that the companies have not effectively rebutted the presumption that the parent debt adjustment should be applied.[39] In ruling that a parent debt adjustment was required in a case involving Indiantown Company, Inc., the Commission stated:

> Based on our analysis, the rule requires that a parent debt adjustment be made in this proceeding. Further, the rule does not allow for specific identification of debt from the parent to the subsidiary utility. Since the utility is included in the consolidated income tax returns of the parent, we believe that it would be very difficult to prove specific identification to only the utility. Rule 25-14.004(3), Florida Administrative Code, states that it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.[40]

Additionally, in the most recent Progress Energy Florida rate case, the Commission found that PEF had not demonstrated that the investment made by Progress Energy in PEF could be attributed to any source other than the general funds of the parent and that PEF did not meet its burden of proof to demonstrate its claim that all contributions made and expected to be made by Progress Energy to PEF in 2009 and 2010 would be from funds generated from common equity issuances at Progress Energy.[41]

Q. PLEASE PROVIDE YOUR ASSESSMENT OF GULF'S POSITION ON THE PARENT DEBT ADJUSTMENT.

A. Gulf witness Mr. Teel claims that the Parent Debt Adjustment should not be made in this case. He makes two arguments: (1) The parent debt adjustment was not an issue

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[39] See Order No. PSC-09-0411-FOF-GU, page 38, issued June 9, 2009, in Docket No. O80318-GU, In re: Petition for rate increase by Peoples Gas System; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009 in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

40 See Order No. PSC-OO-2054-PAA-WS, issued October 27, 2000, in Docket No. 990939-WS, In re: Application for rate increase in Martin County by Indiantown Company, Inc.

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

in the Company's last rate case; and (2) since the last rate case, Gulf Power has paid more in dividends to Southern than Southern has invested in capital contributions to Gulf Power.

The fact that the order in Gulf's last rate case was silent on the subject of a parent debt adjustment provides no support for Gulf's position in this current case. The parent debt adjustment applies unless Gulf can overcome the rebuttable presumption that the rule creates. In this regard, Mr. Teel says that Gulf sent more dividends to Southern Company over a period of years than the amount of equity that Southern invested in Gulf. The fallacy in this reasoning is that it is impossible to "trace dollars" (i.e., attribute particular monies to certain sources of funds). Further, as shown in Schedule D-2, the capital structure of Southern Company, after the elimination of subsidiary debt, has debt outstanding on an ongoing basis. Therefore, in the absence of an all equity capital structure at the parent level, a PDA is appropriate for Gulf Power.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON THE PARENT DEBT ADJUSTMENT.

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. McGLOTHLIN:

Q. Dr. Woolridge, please summarize your testimony for the Commissioners.

A. Good morning, Commissioners. My summary focuses on the appropriate return on equity for Gulf and discusses the most significant ROE issues in this proceeding.

In my opinion, under current market conditions, the appropriate ROE for Gulf is 9.25 percent. In contrast, Gulf witness Dr. Vander Weide has proposed a common equity cost rate of 11.7 percent.

According to the DCF model, the equity cost rate is computed as the dividend yield plus the expected long-term growth rate. There are two issues with this. The first issue is the DCF dividend yield adjustment. I've adjusted the dividend, the amount of the annual dividend by one-half the annual growth rate. This is because companies tend to increase their dividends at different times during the year. This is the approach employed by FERC in its application of the DCF model.

In contrast, Dr. Vander Weide uses a model in which each quarterly dividend is compounded at the end of the year by the long-term growth rate. This approach duplicates the compounding processes in the DCF model, and therefore overstates investors' required return.

The second issue is the DCF growth rate. To estimate the DCF growth rate, I have reviewed Value Line's projections for earnings, dividends, and book value per share, as well as sustainable growth. I've also used the EPS growth rates, the earnings per share growth rates of Wall Street analysts. Where I've used a variety of growth rate measures, Dr. Vander Weide has relied exclusively on one growth rate indicator, that being the projected earnings per share growth rates of Wall Street analysts.

There's a serious error in this approach. As I document in my testimony, a number of studies have evaluated the accuracy of the long-term earnings per share growth rate forecasts of Wall Street analysts. And I want to emphasize, these are the long-term growth rate forecasts, not the forecasts of quarterly and annual earnings. The results of the studies are unanimous. As summarized in the 2010 study by McKinsey, the long-term growth rate forecasts of Wall Street analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent compared to actual earnings growth of 6 percent. As such, relying exclusively on the long-term earnings per share growth rates of Wall Street analysts produces an upwardly biased DCF growth rate.

The risk premium and CAPM approaches require an estimate of the base interest rate and equity risk premium. Dr. Vander Weide employs base interest rates that are well above current market rates. For example, Dr. Vander Weide uses a long-term A-rated bond yield of 6.11 percent. The current yield on long-term A-rated utility bonds is 4.5 percent.

Dr. Vander Weide and I also disagree on the measurement and the magnitude of the equity risk premium. I demonstrate that Dr. Vander Weide's historic and projected equity risk premiums are excessive and include unrealistic assumptions of economic and earnings growth as well as stock returns. For example, Dr. Vander Weide's expected market risk premium presumes a long-term stock market return of 13.3 percent. This is simply unrealistic. In fact, as I point out in my testimony, Dr. Vander Weide's equity risk premiums are well above the equity risk premiums used in the real world of finance, as indicated by surveys of CFOs, companies, and economists.

Dr. Vander Weide's recommended ROE includes a leverage adjustment of 90 basis points. The problem with this is that financial publications and investment firms report capitalizations on a book value basis and not on a market value basis. As I show in my discussion of the capital structure, the book value capitalizations of my proxy group and Gulf are very similar. In fact, there is no change in leverage, because Gulf's financial statements and their financial obligations remain the same.

Furthermore, as I indicate, the leverage adjustment has not really been adopted by other state regulatory commissions. Therefore, in summary, it's my belief that the leverage adjustment is inappropriate in this proceeding as well.

MR. McGLOTHLIN: With several seconds to spare, Dr. Woolridge is available for cross-examination.

CHAIRMAN GRAHAM: And that is very well appreciated.

Intervenors, anything?

Staff?

MR. YOUNG: No questions.

CHAIRMAN GRAHAM: Commissioners?

Redirect.

MR. McGLOTHLIN: No redirect.

CHAIRMAN GRAHAM: Thank you, Dr. Woolridge.

MR. McGLOTHLIN: OPC moves Exhibits 52 through 65 inclusive and the errata sheet, which is 208.

CHAIRMAN GRAHAM: We'll move 52 through 65 into the record, and also Exhibit 208.

(Exhibit Numbers 52 through 65 and 208 were admitted into the record.)

CHAIRMAN GRAHAM: I think it's an opportune time to take a 10-minute break for the court reporter. We'll be back here at 35 after.

(Recess from 11:24 a.m. to 11:35 a.m.)

(Transcript continues in sequence in Volume 10.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1524 through 1736 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 18th day of December, 2011.

Mary Allen Neel

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