BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130040-EI

PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY.
_______________________________/

VOLUME 7

Pages 1206 through 1436

PROCEEDINGS: HEARING

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

DATE: Monday, September 9, 2013

TIME: Commenced at 9:37 a.m.
Concluded at 10:01 a.m.

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

NO EXHIBITS MARKED OR ADMITTED IN THIS VOLUME

P R O C E E D I N G S

(Transcript follows in sequence from Volume 6.)

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the WCF Hospital Utility Alliance ("HUA").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my direct testimony is to address the allowed return on equity and capital structure for ratemaking purposes for Tampa Electric Company ("Tampa Electric" or "Company").

Q. Please summarize your Direct Testimony.

A. I recommend that the Florida Public Service Commission ("Commission") approve a rate of return on equity ("ROE") for Tampa Electric of 9.30%. This recommendation is based on the results from my Discounted Cash Flow ("DCF") analyses for a comparison group of electric companies that has similar bond ratings to Tampa Electric. I also employed the Capital Asset Pricing Model ("CAPM"), but did not directly incorporate the results into my recommendation. In my opinion, a return on equity of 9.30% is a reasonable, even generous, estimate of the required return on equity for an electric company such as Tampa Electric. As I will demonstrate in the following sections of my testimony, the market evidence I have examined supports my ROE recommendation.

I also recommend that the Commission reject the return on equity recommendation of 11.25% of Mr. Robert Hevert, witness for Tampa Electric. As I will demonstrate in Section IV of my Direct Testimony, Mr. Hevert's analyses systematically overstate the current investor required ROE for Tampa Electric.

Q. What exhibits are you sponsoring as a part of your Direct Testimony?

A. I am sponsoring the following exhibits as a part of my Direct Testimony:

Exhibit No. ___(RAB-1) - Resume and Testimony Experience of Richard A Baudino

Exhibit No. ___(RAB-2) - Historical Bond Yields

Exhibit No. ___(RAB-3) - FOMC June 19, 2013 Press Release

Exhibit No. ___(RAB-4) - Historical Daily VIX Values

Exhibit No. ___(RAB-5) - Excerpts from TECO Energy Dec. 31, 2012 SEC 10-K

Exhibit No. ___(RAB-6) - Excerpts from TECO Energy Investor Presentations

Exhibit No. ___(RAB-7) - Tampa Electric Discovery Responses

Exhibit No. ___(RAB-8) - Comparison Group Dividend Yield Calculations

Exhibit No. ___(RAB-9) - Comparison Group Growth and DCF ROE Calculation

Exhibit No. ___(RAB-10) - CAPM ROE Analysis - Comparison Group

Exhibit No. ___(RAB-11) - CAPM Analysis - Historic Market Premium

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Exhibit No. ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2002 through May 2013. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. Exhibit No. ___(RAB-2) shows that the yields on long-term Treasury and utility bonds have declined substantially since early 2002. For example, the average public utility bond yield in January 2002 was 7.69% and the 20-year Treasury Bond yield was 5.69%. As of May 2013 the average public utility bond yield was 4.24% and represents a decline of 345 basis points, or 3.45% from January 2002. Likewise, the 20-year Treasury bond declined to 2.73% in May 2013, a decline of 2.96% from January 2002. Interest rates during 2013 have been at historically low levels.

In 2008, world financial markets experienced tumultuous changes and volatility not seen since the Great Depression. As noted in the SBBI 2009 Yearbook, both large and small company stocks declined around 37% for the year.[1] Investors, in a flight to quality and safety, also pulled their funds out of those corporate bonds that were perceived to be higher risk and invested in the safety of Treasury securities. The 2009 SBBI Yearbook reported that long-term Treasury Bonds returned 25.87% during 2008, while long-term corporate bonds returned 8.78%. Thus, bonds significantly outperformed stocks in 2008. The stocks of electric utilities did not fare well during the financial market upheaval of 2008. The Dow Jones Utility Average

1 *2009 Ibbotson SBBI Classic Yearbook*, Morningstar, page 11.

was down from its opening level in January 2008 of 532.50 to 370.76 at the end of December, a decline of 30.4%. This decline was smaller than the decline in the overall stock market. Utility bond yields also increased significantly during the year, rising from 6.08% in January to a high of 7.80% in November. As investors flocked to the safety of Treasury securities, the yield spread between long-term Treasury securities and the index of public utility bonds widened from 1.73% in January to 3.69% in December, the highest spread during the entire period shown in Exhibit No. ___(RAB-2).

In 2009 and continuing through 2012, utility bond yields fell significantly from November 2008 levels, as did the spread between public utility bond yields and long-term Treasuries. The average utility bond yield in December 2012 was 4.1%, a decline of 370 basis points, or 3.70%, from November 2008. At the end of December 2012 the yield spread between utility bonds and the long-term Treasury bond declined to 1.63%. This is much closer to the historical spread.

On June 19, 2013, the Federal Reserve issued a Federal Open Market Committee ("FOMC") press release indicating that it intended to extend what has been termed "Operation Twist." This refers to the Federal Reserve maturity extension program whereby the Federal Reserve redeems or sells shorter-term treasury securities and uses the proceeds to buy longer-term securities. In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its

> dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative. [Exhibit No. ____(RAB-3) at p. 1].

By reducing the supply of longer-term Treasury securities, the prices of these securities will rise, putting downward pressure on long-term interest rates.

Q. Please compare current financial market conditions with the conditions that were present in Tampa Electric's last rate case, Docket No. 080317-EI.

A. Tampa Electric's last rate case began in August 2008 and the Commission issued its Final Order on April 30, 2009. As I stated earlier, the latter part of 2008 was marked by a severe financial crisis. In 2009 the financial markets began to slowly recover from the tumultuous volatility and substantial losses sustained in 2008 and the country had fallen into a deep recession. The yield on the average public utility bond was 6.48% in August 2008 and by the time the Commission issued its Final Order, that bond yield had risen to 6.9%. The Commission noted on page 47 of its Order that the witnesses in the case recognized that the economy was not in a "normal or stable state."[2] The Commission authorized an ROE of 11.25% with a range of plus

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2 Order No. PSC-09-0283-FOF-EI, *In re: Petition for rate increase by Tampa Electric Co.*, Docket No. 080317-EI, at p. 47 (issued Apr. 30, 2009).

or minus 100 basis points.

Since 2009, financial markets have recovered from the tumult of 2008 and interest rates are near historic lows. The Dow Jones Utility Average, which closed at 334.20 in April 2009, closed at 482.16 as of May 30, 2013, a rise of approximately 44%.

In addition the Chicago Board of Options Exchange ("CBOE") VIX index, a well-known measure of stock market volatility has declined significantly since 2009. At the end of April 2009 the VIX stood at 36.5. At the end of June 2013, the VIX stood at 16.86, indicating far less stock market volatility at the time of this proceeding vis-à-vis Tampa Electric's last rate case. Exhibit No. ____(RAB-4)

Q. What does this suggest for the return on equity in this proceeding?

A. It suggests that the ROE in this case should be considerably lower than in Tampa Electric's last rate case. My ROE analysis in the next section of my testimony supports this conclusion.

Q. How does the investment community regard the electric utility industry as a whole?

A. The June 21, 2013 Value Line report on the Electric Utility (Central) group of companies noted the following regarding the effect of the current low interest rate environment on electric utilities:

> Since mid-May, the prices of most electric utility stocks have declined, while the Value Line Composite Average is almost unchanged. Even so, most electric utility issues are up solidly year to date, and are still trading within their 2016-2018

> Target Price Ranges. Historically, this is an indication that these equities are expensively priced. Income-oriented investors don't have a lot of options, with money market and savings instruments having such low yields. They must be cognizant of the market risks they are assuming when they purchase stocks for their generous dividends.

Q. Briefly describe Tampa Electric Company.

A. Tampa Electric is a wholly owned electric operating subsidiary of TECO Energy, Inc. ("TECO Energy"). According to TECO Energy's 2012 10-K Report, during calendar year 2012, Tampa Electric generated $1,981.3 million in revenues, 48% derived from residential sales, 31% from commercial sales, 9% from industrial sales, and 12% from other sources, including bulk power and sales for resale. Exhibit No. ____(RAB-5) at p. 5. Tampa Electric derives 61% of its generation from coal and 39% from natural gas. The Company's owned generating units supply 94% of total system load requirements, with the remaining 6% coming from purchased power. Exhibit No. ____(RAB-5) at p. 6.

Tampa Electric's "[f]uel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the [Commission's] cost-recovery clauses." Exhibit No. ____(RAB-5) at p. 9. According to TECO Energy's 2012 10-K, "Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the [environmental cost recovery clause]." Exhibit No. ____(RAB-5) at p. 8. Tampa Electric expects to undertake capital investments from 2013 through 2017 totaling approximately $2.3 billion. Exhibit No. ___ (RAB-7) at p. 7. These expenditures will support system growth and reliability, environmental compliance and computer system improvements.

Q. What are the current bond ratings for Tampa Electric?

A. Tampa Electric's senior unsecured bond ratings are currently A3 from Moody's Investor's Services ("Moody's") and BBB+ from Standard and Poor's ("S&P"). Both of these rating agencies have stable ratings outlooks for the Company.

In its Credit Opinion dated May 30, 2013, Moody's noted the following ratings drivers for Tampa Electric:

- Supportive Florida regulatory framework that provides timely recovery of prudently incurred costs and investments.
- Strong credit metrics elevated by bonus depreciation.
- Sizeable increase in capital expenditures funded through debt and parent contributions.
- Solid liquidity profile.

In its Summary Analysis dated June 17, 2013, S&P assigned Tampa Electric an excellent business risk profile and a significant financial risk profile. With respect to business risk, S&P's ratings scale ranges from vulnerable to excellent, meaning that Tampa Electric is at the top of the scale. S&P stated that Tampa Electric's excellent business risk reflects monopolistic, rate-regulated electric and gas businesses that provide an essential service. S&P also stated:

> Tampa Electric Co.'s service territory has faced a strong downturn due to the slowed economy and depressed housing market. However, recent housing statistics and state unemployment rates signal a slow but recovering economy. Although historically high growth rates seen in the past in these areas may take some time to come back, Florida continues to offer attractive incentives that should favor its economy.

With respect to "significant" financial risk, S&P noted that Tampa Electric's financial profile "reflects the consolidated financial measures of its parent, TECO Energy." S&P's ratings scale ranges from "highly leveraged" to "minimal".

TECO Energy's Chief Executive Officer ("CEO") stated in a May 2012 presentation that "TECO Energy expects to generate significant free cash flow after dividends for the next several years", there were "[n]o significant TECO Energy debt maturities until 2015", and TECO Energy expects "cash generation to retire 2015 debt." Exhibit No. ____(RAB-6) at p. 12. In addition, Schedule D-4a, page 2, of Tampa Electric's MFRs show that Tampa Electric will not have any long term debt maturing until April, 2016.

According to S&P's June 17, 2013 Summary Analysis, TECO Energy has announced that "it had entered into a stock purchase agreement to acquire New Mexico Gas Co." S&P's assessment of Tampa Electric's financial risk "previously assumed that the proceeds from [TECO Energy's sale of its] Guatemala assets would be used for reduction of debt" but now S&P's assessment "assumes that this cash will be used for the acquisition" of New Mexico Gas Co.

Additionally, Witness Callahan noted on page 22 of her testimony that the Regulatory Research Associates ("RRA") ranked the Commission as "Above Average 3" on a scale that runs from Above Average 1 to Below Average 3. As such, there are only three state/district regulatory bodies out of the 51 jurisdictions evaluated by RRA that have a better ranking than the Commission. Exhibit No. ____ (SWC-1), Document No. 9 (Alabama, Virginia, and Wisconsin). Notably, the rankings "are intended to be comparative in nature" and are based on a curve so that the majority of jurisdictions receive a ranking of Average 2. Exhibit No. ____ (RAB_7) at pp. 20-21.

Q. Mr. Baudino, what is your conclusion regarding the financial health and overall risk of Tampa Electric?

A. Since its last rate proceeding before the Commission, the Company has had low cost access to capital markets for its construction program and for other corporate purposes. Tampa Electric spent approximately $1.476 billion on capital expenditures from 2009 through 2012. Exhibit No. ____(RAB-7) at p. 1. During that time, Tampa Electric (1) entered a debt exchange in December 2010 with a principal amount of approximately $232 million, maturing in approximately 11 years, at a coupon rate of 5.4%, (2) issued $250 million of 30-year bonds in June 2012 at a coupon rate of 4.10% and (3) issued $225 million of 10-year bonds in September 2012 at a coupon rate of 2.60%. MFR Schedule D-4a at p. 3.

Tampa Electric also benefits from several Commission-approved cost recovery clauses that reduce its business and financial risk profiles and help stabilize its revenues and earnings. Its bond ratings currently enjoy a stable credit outlook from Moody's and S&P. Overall Tampa Electric remains an electric utility with solid financial health and an excellent business risk position.

As I described earlier in my testimony, current interest rates are at or near historic lows. This suggests a much lower return on equity, other things equal, for Tampa Electric than the Commission approved in Docket No. 080317-EI.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Tampa Electric.

A. I employed a Discounted Cash Flow ("DCF") analysis for a group of comparison electric companies to estimate the cost of equity for the Company's regulated electric operations. I also employed several Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope") and

Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922) ("Bluefield").

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and growth over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of comparable investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk and expected return. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. **What are the major types of risk faced in holding the stock of utility companies?**

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), and quality of management are several factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Other things being equal, as the percentage of debt interest to total income increases, so does the financial risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. **Are there any sources available to investors that quantify the risks facing a company?**

A. Yes. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and S&P perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflects these risks. These ratings are widely available and relied upon by investors.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is based on the discounted present value of future cash flows to the investor. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Tampa Electric?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Tampa Electric. Since Tampa Electric is a subsidiary of TECO Energy, it is not publicly traded, thus one cannot estimate a DCF cost of equity on this company directly. It is necessary to use a group of companies that are similarly situated and have reasonably similar risk profiles to Tampa Electric.

Q. Please describe your approach for selecting a comparison group of electric companies.

A. I used several criteria to select a comparison group. First, using the July 2013 issue of AUS Utility Reports, I selected electric companies whose bonds were rated Baa/BBB by either Moody's or S&P. Tampa Electric currently carries senior unsecured bond ratings of BBB+ from S&P and A3 from Moody's, so using the either/or criterion for a BBB/Baa rating assures that the companies in the comparison group carry bond ratings that are slightly below or similar to Tampa Electric. In fact, using a slightly lower Moody's bond rating than Tampa Electric's A3 rating suggests that my ROE analysis is conservative.

From this group, I then eliminated companies that had recently cut or eliminated dividends, were recently or currently involved in merger activities, or had recent experience with significant earnings fluctuations. Companies that did not pass these screens are not appropriate candidates to which one can apply the DCF formula because of unrepresentative market prices (in terms of companies that are merger candidates) or non-constant growth in earnings or dividends. I also eliminated any companies that had recently been or were currently being restructured in a significant way. These screens eliminated the following companies:

- El Paso Electric Company - resumed dividend payments in 2011 after several years of no dividends.
- Entergy Corporation - pending sale of transmission assets to ITC Corporation.
- FirstEnergy Corporation - unstable earnings per share in 2011 and 2012, reduced unregulated earnings.
- NV Energy Inc. - pending acquisition by MidAmerican Energy Holdings Company.
- OGE Energy Corp. - affect on stock price from formation of Master Limited Partnership with CenterPoint Energy.
- PNM Resources - non-constant dividend and earnings growth rates from Value Line (12.5% and 12.0%, respectively).
- TECO Energy - pending purchase of New Mexico Gas Company.

I also eliminated Ameren Corporation and Edison International from the group because Value Line noted that these companies are being affected by low power prices and/or activities associated with their merchant and unregulated generation assets.[3] According to Value Line, Edison International is a different company in 2013 than it was in 2012. Edison International booked a $5.11 per share loss from its discontinued unregulated power generating business. Likewise, Value Line

3 Value Line Investment Survey, report for Ameren dated June 21, 2013 and for Edison International dated May 3, 2013.

reported that Ameren discontinued its merchant generation business and booked an $0.82 per share loss in the March quarter of 2013. Value Line currently forecasts negative earnings and book value growth rate for Ameren.

Finally, I eliminated PG&E Corporation due to ongoing effects from a gas pipeline explosion.[4] This uncertainty is affecting near-term earnings growth forecasts for PG&E.

The resulting comparison group of 16 electric companies that I used in my analysis is shown in the table below.

4 Value Line Investment Survey, report for PG&E dated May 3, 2013.

TABLE 1
ELECTRIC UTILITY COMPARISON GROUP

		S&P	Moody's
1	American Electric Power Co.	BBB	Baa2
2	Black Hills Corporation	BBB+	A3
3	Cleco Corporation	BBB	Baa2
4	CMS Energy Corporation	BBB/BBB-	Baa2
5	Consolidated Edison, Inc.	A-	A3/Baa1
6	Dominion Resources, Inc.	A	Baa1
7	Great Plains Energy Incorporated	BBB/BBB-	Baa1/Baa2
8	Hawaiian Electric Industries, Inc.	BBB-	Baa2
9	Otter Tail Corp.	BBB-/BB+	Baa2
10	Pepco Holdings, Inc.	A-/BBB+	Baa1/Baa2
11	Pinnacle West Capital Corp.	BBB+	Baa1
12	SCANA Corporation	BBB+	Baa1/Baa2
13	UIL Holdings Corporation	BBB	Baa2
14	UNS Energy Corp.	BBB-	Baa2
15	Westar Energy, Inc.	BBB+	A3
16	Wisconsin Energy Corporation	A-/BBB+	A2/A3

Q. **What was your first step in determining the DCF return on equity for the comparison group?**

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from January through June 2013. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the group is 4.00%. These calculations are shown in Exhibit No. ____(RAB-8).

Q. What was the range of monthly dividend yields during the six-month period?

A. Page 3 of Exhibit No. ____(RAB-8) shows that the monthly average yields for the comparison group ranged from 3.80% in April to 4.19% in January, with the most recent June yield being 4.11%. In my opinion, the average six-month yield of 4.00% is a reasonable proxy for the current dividend yield in this case.

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

In this analysis, I relied on three major sources of analysts' forecasts for growth. These sources are the Value Line Investment Survey, Zacks, and Thomson Financial.

Q. Please briefly describe Value Line, Zacks, and Thomson Financial.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers several thousand companies. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of data elements.

Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks is an investment service that gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth.

Like Zacks, Thomson Financial also provides investment research on numerous companies. Thomson also compiles and reports consensus analysts' forecasts of earnings growth. I obtained the Thomson Financial forecasts from Yahoo! Finance.

Both Zacks and Thomson Financial provide five-year earnings growth forecasts, which I have used in my DCF analyses.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and by virtue of their continual updating and marketing by their sponsor obviously fill a market demand for such information.

Q. How did you utilize your data sources to estimate growth rates for the comparison group?

A. Exhibit No.____(RAB-9) presents the Value Line, Zacks, and Thomson Financial forecasted growth estimates. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (5) of Exhibit No.____(RAB-9).

I also adjusted the Value Line dividend growth rate for Pinnacle West Capital Corp. to recognize 4 dividend payments in 2012, rather than the five declarations that were included by Value Line in the "Div'd Decl'd per sh" line in that Company's report. This reduced the three-year historical average dividends per share data that I used to calculate compound growth through the 2016 - 2018 time period. This had the effect of increasing the compound dividend growth rate from 2.0% to 3.62%.

I also utilized the sustainable growth formula in estimating the expected growth rate. The sustainable growth method, also known as the retention ratio method, recognizes that the firm retains a portion of its earnings to fuel growth in dividends. These retained earnings, which are plowed back into the firm's asset base, are expected to earn a rate of return. This, in turn, generates growth in the firm's book value, market value, and dividends.

The sustainable growth method is calculated using the following formula:

$$G = B * R$$

Where: *G = expected retention growth rate*
B = the firm's expected retention ratio
R = the expected return

In its proper form, this calculation is forward-looking. That is, the investors' expected retention ratio and return must be used in order to measure what investors anticipate will happen in the future. Data on expected retention ratios and returns may be obtained from Value Line.

The expected sustainable growth estimates for the comparison group are presented in Column (3) on page 1 of Exhibit No. ____(RAB-9). The data came from the Value Line forecasts for the comparison group.

Q. How did you approach the calculation of earnings growth forecasts in this case?

A. For purposes of this case, I looked at two different methods for calculating the expected growth rates for my comparison group. For Method 1, I calculated the average of all the growth rates for the companies in my comparison group using Value Line, Zacks, and Thomson. For Method 2, I calculated the median growth rates for my comparison group. The median value represents the middle value in a data range and is not influenced by excessively high or low numbers in the data set. The median growth rate for each forecast provides additional valuable information regarding expected growth rates for the group.

I also excluded the Value Line earnings growth estimate of 21.50% for Otter Tail Corp. from the calculation of the average Value Line earnings growth estimate. Clearly, 21.50% is an anomalous percentage and would only serve to inflate the average earnings growth calculation for the comparison group. By way of comparison, the next highest growth rate estimate for the companies in my comparison group in 12.0%.

The expected growth rates produced from these two methods fall in a range from 3.31% to 5.95%.

Q. How did you proceed to determine the DCF return on equity for the electric comparison group?

A. To estimate the expected dividend yield (D_1) for the group, the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

I then added the expected growth rates to the expected dividend yield. The calculations of the resulting DCF returns on equity for both methods are presented on page 2 of Exhibit No. ____(RAB-9).

Q. Please explain how you calculated your DCF cost of equity estimates.

A. Page 2 of Exhibit No. ____(RAB-9) presents the DCF results utilizing the two different methods I described earlier. Method 1 utilizes the average growth rates for the comparison group. I used the Value Line earnings and dividend growth forecasts and the consensus analysts' forecasts. The average for the comparison group is 9.32% and the midpoint is 9.08%.

Method 2 employs the median growth rates from Value Line, Zacks, and Thomson. The average DCF return on equity is 9.08% and the midpoint of the results is 8.73%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away risks specific to a particular company so that the investor is left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[5] There is evidence that beta is not the primary factor in determining the risk of a security. Beta coefficients usually describe only a small amount of total investment risk. Finally, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for June 25, 2013. This edition covers nearly 7,000 stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth in earnings and book value for the companies Value Line follows. I have presented these two growth rates and the average on page 2 of Exhibit No.____(RAB-10). The average growth rate is 11.43%. Combining this growth rate with the average expected dividend yield of the Value Line companies of 0.71% results in an expected market return of 12.18%. The detailed calculations are shown on page 1 of Exhibit No.____(RAB-10).

5 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206– 211, 2007 edition.

I also considered a supplemental check to this market estimate. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2013 Valuation Yearbook.* Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit No. ____(RAB-11) presents the calculation of the market return using the historical data.

Q. Please address the use of historical earned returns to estimate the market risk premium.

A. The use of historic earned returns on the S&P 500 to estimate the current market risk premium is rather suspect because it naively assumes that investors currently expect historic risk premiums to continue unchanged into the future regardless of present or forecasted economic conditions. Brigham, Shome, and Vinson noted the following with respect to the use of historic risk premiums calculated using the returns as reported by Ibbotson and Sinquefield (referred to in the quote as "I&S"):

> There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet can result in significant differences in the final outcome.[6]

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6 Brigham, E.F., Shome, D.K. and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost

In summary, the use of historic earned returns should be viewed with a great deal of caution. There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from January through June 2013. The 20-year Treasury bond is often used by rate of return analysts as the risk-free rate, but it contains a significant amount of interest rate risk. Interest rate risk is the inverse relationship between interest rates and prices. Generally, the longer the term of the bond, the more risk the investor assumes regarding changes in interest rates over time. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM may be estimated.

Q. What is your estimate of the market risk premium?

A. Exhibit No.____(RAB-10), line 9 of page 1, presents my estimates of the market risk premium based on a DCF analysis applied to current market data. The market risk premium is 9.42% using the 20-year Treasury bond and 11.31% using the five-year Treasury bond.

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of Equity," *Financial Management*, Spring 1985, pp. 33-45.

Utilizing the historical Ibbotson data on market returns, the market risk premium ranges from 4.70% to 6.70%. This is shown on Exhibit No.____(RAB-11).

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric company comparison group from most recent Value Line reports. The average of the Value Line betas for the electric group is .71.

Q. Please summarize the CAPM results.

A. The CAPM results using the 20-year and five-year Treasury bond yields and Value Line market return data range from 8.89% to 9.44%. Exhibit No. ___ (RAB-10) at p. 1, line 14.

The CAPM results using the historical Ibbotson data range from 6.10% to 7.52%. These results are shown on Exhibit No.____(RAB-11).

<u>**Conclusions and Recommendations**</u>

Q. Please summarize the cost of equity you recommend the Commission adopt for Tampa Electric.

A. I recommend that the Commission adopt the DCF model I developed and the cost of equity estimates for the comparison group of electric utility companies that I compiled. The results for the electric company comparison group using the constant-growth DCF model and the expected growth rate forecasts ranged from 8.73% to

9.32%. Based on this range of results, I recommend that the Commission adopt a 9.30% return on equity for Tampa Electric in this proceeding, which is at the top end of reasonable returns established by these estimates of investor required ROEs. I offer this recommendation to the Commission as a just and reasonable estimate of investor return on equity requirements for an electric utility such as Tampa Electric.

Finally, it should be noted that most of the CAPM results are significantly lower than the DCF results in this proceeding. This is especially the case with the historical formulation of the CAPM. I do not rely on the CAPM for my ROE recommendation, but these results suggest that my recommended ROE of 9.30% is generous based on current capital market conditions.

Capital Structure and Weighted Cost of Capital

Q. Did you review Tampa Electric's requested capital structure?

A. Yes. The Company's requested capital structure and weighted cost of capital is presented in Schedule D-1A and is supported by the Direct Testimony of Tampa Electric witnesses Hevert and Callahan. Tampa Electric's proposed equity ratio for purposes of this case is 54.2%.

Q. How does Tampa Electric's proposed level of equity compare to the equity levels for the companies in your comparison group?

A. Tampa Electric's proposed level of equity is significantly higher than the average of the companies in my comparison group. Table 2 below presents the common equity ratios for the comparison group. I obtained the data from the Value Line Investment Survey and from AUS Utility Reports, July 2013.

TABLE 2
COMPARISON GROUP CAPITAL STRUCTURES

		2012 Value Line Common Equity	AUS Common Equity
1	American Electric Power Co.	49.4%	45.0%
2	Black Hills Corporation	56.8%	49.5%
3	Cleco Corporation	54.4%	53.1%
4	CMS Energy Corporation	31.6%	30.1%
5	Consolidated Edison, Inc.	54.1%	49.8%
6	Dominion Resources, Inc.	38.2%	33.4%
7	Great Plains Energy Incorporated	54.4%	46.1%
8	Hawaiian Electric Industries, Inc.	53.1%	47.4%
9	Otter Tail Corp.	54.4%	54.6%
10	Pepco Holdings, Inc.	52.7%	42.3%
11	Pinnacle West Capital Corp.	55.4%	53.0%
12	SCANA Corporation	45.6%	43.7%
13	UIL Holdings Corporation	41.1%	38.9%
14	UNS Energy Corp.	37.7%	37.0%
15	Westar Energy, Inc.	48.8%	45.7%
16	Wisconsin Energy Corporation	48.0%	44.9%
	Average	48.5%	44.7%

Source: Value Line Reports 2013; AUS Utility Reports, July 2013

It is clear from Table 2 that Tampa Electric's equity ratio greatly exceeds the average equity ratio of the comparison group. This suggests that Tampa Electric's lower financial risk relative to the comparison group should result in a lower required return on equity by investors in Tampa Electric. However, for purposes of this case, I will recommend an ROE for Tampa Electric consistent with the ROE results from the comparison group. This underscores the reasonableness of my ROE recommendation for Tampa Electric in this proceeding.

Q. Please provide Tampa Electric's proposed capital structure and your calculation of its weighted cost of capital.

A. Please refer to Table 3 below for the calculation of my recommended weighted cost of capital for Tampa Electric. Using the Company's requested capital structure, the weighted cost of capital is 5.91%.

TABLE 3
HUA ADJUSTED WEIGHTED COST OF CAPITAL

	Amount	Pct.	Cost	Weighted Cost
Long-Term Debt	$1,525,392	35.15%	5.40%	1.90%
Short-term Debt	$24,646	0.57%	1.47%	0.01%
Customer Deposits	$112,864	2.60%	2.20%	0.06%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	1,833,899	42.26%	9.30%	3.93%
ADIT	835,173	19.24%	0.00%	0.00%
Tax Credits	7,999	0.18%	8.54%	0.02%
Totals	$4,339,973	100.00%		5.91%

IV. RESPONSE TO TAMPA ELECTRIC TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. Robert Hevert?

A. Yes.

Q. Please summarize Mr. Hevert's testimony and approach to return on equity.

A. Mr. Hevert employed three methods to estimate the investor required rate of return for Tampa Electric: (1) the constant growth DCF model, (2) the CAPM, and (3) the bond yield plus risk premium model. On page 19 of his Direct Testimony, Mr. Hevert explained that he relied on the results of the constant growth DCF model and considered the CAPM and risk premium approaches as "corroborating methodologies." Mr. Hevert also devoted Section VII of his Direct Testimony to a discussion of business risks facing Tampa Electric. In Section VIII, Mr. Hevert included a discussion of current capital market conditions and analyzed yield spreads in support of his 11.25% ROE recommendation.

With respect to the DCF model, Mr. Hevert developed a proxy group consisting of eleven companies using several selection criteria. His constant growth DCF results ranged from 8.80% to 13.19%.

With respect to the CAPM, Mr. Hevert's results ranged from 7.42% to 12.20%.

Finally, Mr. Hevert's formulation of the bond yield plus risk premium approach resulted in a ROE range of 10.23% to 10.76%.

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for Tampa Electric of 10.50% to 11.50%, concluding that the cost of equity for Tampa Electric is 11.25%

Q. Please summarize your conclusions with respect to Mr. Hevert's ROE recommendation of 11.25%.

A. Mr. Hevert's analyses systematically overstated the investor required ROE for a regulated electric company such as Tampa Electric.

First, Mr. Hevert included proxy company growth rates that are excessive and unrepresentative of investor expected long-run growth rates for regulated electric utility companies like Tampa Electric. Adjusting Mr. Hevert's DCF analysis to remove these excessive growth rates appreciably lowers his DCF ROE.

Second, Mr. Hevert's CAPM range of results is biased upward by using forecasted Treasury Bond yields. Forecasted bond yields are not appropriate for formulating a CAPM ROE. Instead, current market bond yields should be used because they reflect current investor expectations and market return requirements. Mr. Hevert's CAPM results using the current Treasury Bond yield are similar to mine, although he should also have used the 5-year Treasury Bill as an appropriate proxy for the risk-free rate of return. Mr. Hevert also included a CAPM analysis using the Sharpe ratio, which is an inappropriate modification to the traditional CAPM analysis that should be rejected by the Commission.

Third, Mr. Hevert's bond yield plus risk premium analysis is also inflated by using forecasted bond yields. In addition, the risk premium method is far less precise that the DCF method, which uses current market data that are more reflective of investor required returns today.

DCF Analyses

Q. Please summarize Mr. Hevert's approach to the DCF model and its results.

A. Mr. Hevert began his DCF analysis with the selection of a proxy group of companies. Mr. Hevert discusses his approach and the selection criteria he used beginning on page 14 of his Direct Testimony. After applying these screening criteria, Mr. Hevert went on to eliminate Edison International and Integrys Energy Group. His final proxy group of eleven companies is presented on page 17 of his Direct Testimony.

Q. What are Mr. Hevert's DCF ROE results using this proxy group?

A. Mr. Hevert summarized his DCF results on pages 26 and 27 of his Direct Testimony. The proxy group results range from 8.80% to 13.19%.

Q. Do these ranges represent reasonable estimates of the investor-required roe for a company like Tampa Electric?

A. No. Mr. Hevert's DCF results are significantly overstated.

Q. What is the main cause of Mr. Hevert's overstatement of the DCF model?

A. The main cause is Mr. Hevert's inclusion of excessive earnings growth forecasts that significantly bias his DCF results upward.

As I mentioned in Section III of my Direct Testimony, I omitted PNM Resources from my comparison group of electric companies. This is due to excessive, non-constant earnings and dividend growth rates currently being forecasted by Value Line for PNM. Mr. Hevert's Exhibit No. ___ (RBH-1), Document No. 2 clearly bears this out, with a Value Line earnings growth estimate of 16.00%. Including this growth rate in his DCF analysis biased his ROE result upward.

This is also the case for Otter Tail Corp. Mr. Hevert included a Value Line earnings growth estimate of 24.0% in his DCF ROE calculations, again biasing his results substantially upward.

Growth rates of 16% and 24% have no place in a DCF ROE analysis for regulated electric utilities. These growth rates are clearly the product of special circumstances with PNM Resources and Otter Tail and should be excluded from Mr. Hevert's analysis. Given the evidence concerning expected growth rates for my comparison group, 16% and 24% earnings growth rates are in no way representative of investors' anticipated performance for Tampa Electric.

Q. Did you prepare an analysis that adjusted for the excessive growth rates and resulting ROEs that you just discussed?

A. Yes. Please refer to Table 4, which presents adjusted results for Mr. Hevert's DCF analyses. I developed this table using Mr. Hevert's spreadsheet that was provided as part of his work papers. I chose to use the DCF ROE results from the 180-day average of stock prices for Mr. Hevert's group because I also used a six-month average of stock prices in my comparison group DCF analysis. Excluding Otter Tail and PNM Resources results in an average DCF ROE of 9.62%.

TABLE 4
ADJUSTED HEVERT GROUP DCF ROE

Company	Mean ROE
American Electric Power Company, Inc.	7.76%
Cleco Corp.	7.98%
Empire District Electric	12.79%
Great Plains Energy Inc.	10.81%
IDACORP, Inc.	6.93%
Otter Tail Corporation	16.90%
Pinnacle West Capital Corp.	11.29%
PNM Resources, Inc.	14.19%
Portland General Electric Company	7.91%
Southern Company	9.38%
Westar Energy, Inc.	11.76%
Group Average	10.70%
Group Average excl. Otter Tail and PNM	9.62%

Q. Are the revised results in Table 4 still overstated?

A. Yes. They are overstated because Mr. Hevert did not include Value Line's dividend growth forecasts. Currently, Value Line is forecasting lower near-term dividend growth than earnings growth. As may be seen from the results in my Exhibit No.____(RAB-9), median and average dividend growth for my comparison group is 3.31% and 4.29%, respectively. This is much lower than the earnings growth rates I used in my analysis, which range from 5.17% to 5.95%.

With respect to regulated utility companies, dividend growth provides the primary source of cash flow to the investor. It is certainly the case that earnings growth fuels dividend growth and should be considered in estimating the ROE using the DCF model. However, Value Line's dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. I weighted earnings growth 75% and dividend growth 25% in my growth calculations,[7] so I acknowledge that earnings growth is the primary factor considered by investors. But it should not be considered the only factor.

Q. What are the current dividend growth rates for the companies in Mr. Hevert's proxy group?

A. Table 5 below presents the Value Line projected dividend growth rates for the companies in Mr. Hevert's proxy group excluding PNM Resources. The average dividend growth rate for his proxy group is 4.91% and the median growth rate is 3.62%.

7 In other words, my average comparison group growth rate averaged three earnings growth estimates and one dividend growth estimate.

TABLE 5
HEVERT PROXY GROUP
DIVIDEND GROWTH RATES

Company	V/L Dividend Growth
American Electric Power Company, Inc.	4.09%
Cleco Corp.	10.00%
Empire District Electric	3.50%
Great Plains Energy Inc.	6.00%
IDACORP, Inc.	7.00%
Pinnacle West Capital Corp.	3.62%
Portland General Electric Company	3.50%
Southern Company	3.50%
Westar Energy, Inc.	3.00%
Average	4.91%
Median	3.62%

Q. What would be the resulting DCF ROE using the average dividend growth rate?

A. Excluding PNM Resources and Otter Tail, Mr. Hevert's proxy group dividend yield using the 180-day average stock price would be 4.11%. The resulting DCF ROE would then be:

4.11%(1 + (0.5 * 4.91%) + 4.21% =*
4.21% + 4.91% =
9.12% DCF ROE

CAPM

Q. Briefly summarize Mr. Hevert's approach to estimating the CAPM ROE.

A. On page 30 of his Direct Testimony, Mr. Hevert testified that he used three estimates of the yield on 30-year Treasury Bonds as proxies for the risk-free rate: the current

30-day average yield of 3.12%, a near-term projected yield of 3.25%, and a long-term projected yield of 5.10%. Mr. Hevert did not consider any shorter maturity bonds, such as the 5-year Treasury note.

Mr. Hevert then calculated two different ex-ante measures of total market returns. The first utilized an estimated total market return on the S&P 500 based on data from Bloomberg and Capital IQ. Total market returns from these two sources were rather close, with a 13.00% market return using Bloomberg data and a 12.93% return using Capital IQ data. The second utilized an approach that employed Mr. Hevert's estimate of the Sharpe ratio applied to the historical market risk premium of 6.60%, which resulted in an estimated market risk premium of 6.03%.

Mr. Hevert used two different estimates for beta: Bloomberg and Value Line.

Using the current 30-year Treasury bond yield, Mr. Hevert's CAPM results ranged from 7.42% to 10.22%. Using the forecasted long-term 30-year Treasury bond yield, his results ranged from 9.41% to 12.20%. CAPM results using the near-term projected bond yield did not differ significantly from the results using the current bond yield.

Q. Is it appropriate to use forecasted or projected bond yields in the CAPM?

A. No. Current interest rates embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted Treasury bond yields used by Mr. Hevert are speculative at best and may or may not come to pass. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates that should be used in both the CAPM and in the bond yield plus risk premium analysis. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

Q. Should Mr. Hevert have considered shorter term Treasury yields in his CAPM analyses?

A. Yes. In theory, the risk-free rate should have no interest rate risk. 30-year Treasury Bonds do tend to face this risk, which is the risk that interest rates could rise in the future and lead to a capital loss for the bondholder. Typically, the longer the duration of the bond, the more interest rate risk will increase. The 5-year Treasury note has much less interest rate risk than 20-year or 30-year Treasury Bonds and may be considered one reasonable proxy for a risk-free security. My CAPM analysis shows that the ROE using a 5-year Treasury note would be only 9.16%. This is much lower than any of the CAPM estimates provided by Mr. Hevert.

Q. Do you agree with adjusting the historical risk premium using the Sharpe ratio?

A. No, I do not. Mr. Hevert's use of the Sharpe ratio substantially deviates from common formulations of the CAPM and, in my view, it is highly unlikely that investors would use such an unorthodox method to derive their expected market risk premium and CAPM return. Mr. Hevert provided no support that investors actually use the Sharpe ratio in the manner he put forward in his Direct Testimony. I recommend that the Commission reject Mr. Hevert's alternative CAPM using the Sharpe ratio.

Risk Premium

Q. Please summarize Mr. Hevert's risk premium approach.

A. Mr. Hevert developed a historical risk premium using Commission-allowed returns for regulated utility companies and 30-year Treasury bond yields from 1980 through February 13, 2013. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. His Exhibit No. ___ (RBH-1), Document No. 6 shows the risk premium return on equity to be in a range of 10.23% to 10.74%. The 10.74% result was derived using Mr. Hevert's projected Treasury Bond yield of 5.10%.

Q. Please respond to Mr. Hevert's risk premium analysis.

A. First, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time. As such, this approach is a "blunt instrument," if you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis over a certain period of time.

Second, I recommend that the Commission reject the use of the forecasted Treasury bond yield of 5.10% for the same reasons I described in my response to Mr. Hevert's CAPM approach.

Other ROE Considerations

Q. On page 45 of his Direct Testimony, Mr. Hevert concluded that Tampa Electric's capital spending program suggested an ROE above the mean results of his cost of equity analyses. Do you agree?

A. No. The Commission should not inflate Tampa Electric's ROE due to its capital spending program.

First, my ROE analyses do not support an ROE above 9.30% for Tampa Electric in today's capital markets. In this low interest rate environment, an 11.25% ROE can in no way be justified on the basis of current financial market evidence.

Second, any risk regarding the Company's capital spending program has already been accounted for in its BBB+/A3 bond ratings. By estimating the cost of equity using companies with similar bond ratings, the resulting ROE will need no further upward adjustment. Notably, besides the screens used to select his proxy group, Mr. Hevert did not perform any company by company study of the risks of the proxy companies he selected. Exhibit No. ___ (RAB-7) at pp. 2-3. In other words, he has not performed a comprehensive analysis to determine whether Tampa Electric is more risky than the proxy group he selected and should therefore be provided a ROE at the high end of his range of returns. Neither he, nor other Tampa Electric witnesses testifying concerning Tampa Electric's capital expenditures and rate of return, performed any study to compare the magnitude of Tampa Electric's forecasted capital expenditures with those of other electric utilities or the proxy group. Exhibit No. ___ (RAB-7) at pp. 4-7. In fact the only document that Tampa Electric could produce that purportedly compared Tampa Electric's forecasted capital expenditures to other utilities, actually compared TECO Energy's (not Tampa Electric) forecasted capital expenditures to other electric utility holding companies. Exhibit No. ___ (RAB-7) at pp. 8-12. In addition, that study showed that TECO Energy's forecasted capital expenditures (1) in 2013 were the 27th highest (in the lowest quintile), (2) in 2014 were the 24th highest (*i.e.*, in the bottom third), and (3) in 2015 were the 28th highest (again in the lowest quintile) out of 34 holding companies. Exhibit No. ____(RAB-7) at p. 10.

Third, it is important to note that Tampa Electric's 54.2% equity ratio is far higher than the average common equity ratio of my comparison group, which ranges from 44.7% to 48.5%. Given Tampa Electric's higher equity ratio, a further upward adjustment to the ROE is not justifiable. Obviously, investors would be pleased with a ROE of 11.25%, but Florida ratepayers would have to shoulder a burdensome increase in rates to support this ROE, compared to the 9.3% I recommend. I suggest to the Commission that my recommended 9.3% ROE represents a fair and reasonable balance of interests between ratepayers and shareholders. Notably, in May 2013, TECO Energy provided a presentation to investors suggesting that it expects that its cash flow will be sufficient to "[s]upport Tampa Electric's capital spending program without issuing equity." Exhibit No. ___ (RAB-6) at p. 6. In May 2012, TECO Energy asserted that it "expects to generate significant free cash flow after dividends for the next several years" and that it expected "cash generation to retire 2015 debt." Exhibit No. ____ (RAB-6) at p. 12.

Tampa Electric's purported need for a high common equity ratio and ROE to support its "financial integrity" is also not supported by the Company. Prior to filing its testimony, Tampa Electric failed to "quantify or compare the costs and benefits of maintaining or enhancing Tampa Electric's 'financial integrity.' " Exhibit No. ___ (RAB-7) at p. 13; *see* Exhibit No. ___ (RAB-7) at pp. 14-18.

Despite not studying the costs and benefits, Tampa Electric increased its investor sourced common equity ratio from 47.12% in the first quarter of 2007 to 53.78% in the fourth quarter of 2012. Exhibit No. ___ (RAB-7) at p. 28. There is also a noticeable increase in Tampa Electric's common equity ratio before it filed this rate case. From the first quarter of 2007 through the third quarter of 2012, Tampa Electric's common equity ratio never exceeded 52.04%, but now that Tampa Electric has filed for an increase in base rates, it common equity ratio has increased to 54.2%. Exhibit No. ___ (RAB-7) at p. 28.

Q. Beginning on page 45 of his Direct Testimony, Mr. Hevert discussed the need to reflect flotation costs in the allowed ROE, though he did not make a specific adjustment for flotation costs. Should the Commission add a flotation cost adjustment to the cost of equity for Tampa Electric?

A. No. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

In addition, TECO Energy recently stated that it will "[s]upport Tampa Electric's capital spending program without issuing equity." Exhibit No. ___ (RAB-6) at p. 6.

Q. On page 64 of his direct testimony, Mr. Hevert concluded that simply observing that long-term Treasury rates are at historically low levels is not a sufficient level of analysis to conclude that the cost of equity for regulated utilities is at a "commensurately low level." Please respond to Mr. Hevert's position here.

A. Although utility ROEs may not have fallen in lock step with Treasury bond yields, these lower yields indicate that required returns on common equity are indeed lower than they otherwise would be if Treasury yields were higher. Utility company stocks are interest rate sensitive and required returns tend to rise and fall with the general movement of interest rates.

Mr. Hevert's Exhibit No. ___ (RBH-1), Document No. 6 also provides support for the proposition that required ROEs are lower than they were during the time of Tampa Electric's last rate case. According to the allowed ROE data in Exhibit No. ___ (RBH-1), Document No. 6, the average allowed ROE from August 2008 through April 2009 was 10.5%. I would note that Tampa Electric's allowed ROE of 11.25% was by far the highest Commission-allowed ROE during that period. During 2013, the average allowed ROE was 9.75%. Thus, allowed ROEs have declined in connection with the decline in Treasury bond yields since the Company's last rate proceeding, although they have not declined as much.

In conclusion, current market evidence and recent Commission allowed returns all show that Mr. Hevert's recommended ROE of 11.25% for Tampa Electric is excessive, unreasonable, and should be rejected by the Commission.

Q. Does this complete your prepared direct testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY) DOCKET NO. 130040-EI
TAMPA ELECTRIC COMPANY)

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies, large consumers of electricity and other market participants. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the

Florida Public Service Commission ("Commission") in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to numerous industrial, commercial, Public Service Commission and utility clients, including international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. **Do you have previous experience in regulatory proceedings before the Commission?**

A. Yes. Initially in my career, as a Staff member of the Commission, I was involved in rate proceedings involving many of the electric utilities in the State of Florida, including Tampa Electric Company ("Tampa Electric," "TECO," or "Company"). Since that time, I have been involved in a number of Progress Energy and Florida Power and Light Company

("FPL") rate proceedings as well as a generic DSM proceeding for all Florida electric utilities.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the WCF Hospital Utility Alliance ("HUA"), a group of hospitals taking service from Tampa Electric.

Q. What is the purpose of your testimony?

A. I will address issues associated with Tampa Electric's proposed 12 Coincident Peak and 50% Average Demand ("12 CP and 50% AD") class cost of service study for production plant. As I will discuss, the Company's proposed class cost of service methodology to allocate fixed production costs is not reasonable and produces an unjustified cost shift to the general service demand ("GSD" or "general service demand") class.

The Company also has proposed to utilize a minimum distribution system ("MDS" or "minimum distribution system") methodology to classify and allocate distribution function costs. The Company's testimony appears to support the use of that methodology only if the Commission adopts the Company's proposed 12 CP and 50% AD class cost of service study. However, an interrogatory response provided by Tampa Electric witness William Ashburn appears to clarify that it is the Company's intent to support the use of the MDS methodology regardless of the class cost of service methodology the Commission requires for production plant. I strongly support the use of an MDS methodology. I will discuss the Company's MDS analysis and recommend that it be adopted by the Commission in this case regardless of the class cost of service methodology the Commission requires.

While Tampa Electric has presented a 12 CP and $1/13^{th}$ AD class cost of service study, the Company did not include its MDS distribution cost classification and allocation methodology in this study. Though I generally believe it would be most appropriate to use a winter peak or a summer/winter peak methodology to allocate Tampa Electric's fixed production costs to rate classes, I will present a 12 CP and $1/13^{th}$ AD methodology that incorporates the Company's MDS methodology for allocating distribution costs and recommend adoption of this study by the Commission in this case.

I will also discuss Tampa Electric's proposed revenue allocation to rate classes of its requested $133.645 million base rate revenue increase.[1] While I do not oppose the Company's general methodology to allocate the approved revenue increase to rate classes, the specific allocation proposed by Tampa Electric, which is based on its recommended class cost of service methodology, is not reasonable. I will present a more accurate revenue allocation based on the HUA recommended 12 CP and $1/13^{th}$ AD + MDS analysis cost of service study.

Finally, I will address Tampa Electric's proposed general service rate class rate design. Specifically, I discuss the proposed increases to the GS energy and demand charges and will recommend an alternative based on cost of service unit cost results.

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[1] Tampa Electric's total revenue increase request is $134.841 million, comprised of a $133.645 million base rate increase and a $1.194 million increase in service charges.

Q. Would you summarize your conclusions and recommendations?

A. Yes.

- **Tampa Electric has based its proposed rate class increases on the results of its 12 CP and 50% Average Demand cost of service study. As I discuss in this testimony, the Company's proposal is unreasonable and not supported by any substantial evidence. Tampa Electric's proposal is not consistent with cost causation and has not been justified by the Company in this case. The main attribute of Tampa Electric's proposed 12 CP and 50% AD methodology is to shift costs without sufficient justification to general service demand customers. The Commission should adopt a 12 CP and 1/13th AD production demand method in this case.**

- **Tampa Electric has developed a reasonable Minimum Distribution System analysis to classify and allocate distribution costs to rate classes. This study follows the methodologies discussed by the National Association of Regulatory Utility Commissions ("NARUC") in its Electric Utility Cost Allocation Manual and is also consistent with widely used distribution cost of service methods adopted by regulatory commissions in other states. The Company's MDS study should be adopted by the Commission, together with a 12 CP and 1/13th AD production demand allocation method. The MDS analysis demonstrates that existing rates, without recognition of the minimum costs of connecting/serving a customer, will cause GSD customers to subsidize other customers.**

- **Any Commission approved revenue increase in this case should be apportioned to rate classes based on the results of the HUA recommended 12 CP and 1/13th AD + MDS class cost of service study so that class rate of return parities are set to 1.0, subject to the restriction that no rate class receives an increase greater than 150% of the system average base rate increase and that no class receives a rate decrease.**

- **Tampa Electric's proposed General Service Demand class rate design should be modified to provide a more reasonable balance between the proposed increases in the energy charges and the demand charge of the rate, following unit cost of service results.**

II. COST ALLOCATION ISSUES

Q. Have you reviewed the class cost of service studies filed by Tampa Electric in this case?

A. Yes. Consistent with the instructions for the Minimum Filing Requirements ("MFR"), Tampa Electric has prepared a 12 CP and 1/13th average demand based cost of service study in this case, but also has developed a 12 CP and 50% AD methodology. The Company recommends adoption by the Commission in this case of the 12 CP and 50% AD method. Tampa Electric also proposes a minimum distribution system methodology to classify and allocate distribution costs if the Commission adopts its recommended 12 CP and 50% AD method.

Q. Do you agree with the Company's class cost of service proposals?

A. In part. While I support the Company's proposed adoption of the MDS method to classify and allocate distribution costs, I strongly oppose Tampa Electric's recommendation to utilize a 12 CP and 50% AD methodology to allocate fixed production demand costs. I will address Tampa Electric's MDS methodology more fully in a subsequent section of my testimony.

With regard to Tampa Electric's 12 CP and 50% AD proposal, this production demand method is not supportable by any reasonable economic analysis or principle and simply results in a substantial cost shift to the general service class. Tampa Electric witness Ashburn's testimony does not provide any reasonable basis to adopt this method beyond a general observation that energy usage is a factor in determining what type of generation to install (i.e., base load vs. intermediate vs. peaking). However, there is no evidence presented to justify assigning 50% of fixed production demand related costs on the basis of rate class energy use, including energy use during off-peak periods as opposed to any other percentage, or to demonstrate that assignment of 50% of fixed production costs on the basis of energy use is more appropriate than an assignment of 8% as would occur under the 12 CP and 1/13th AD class cost of service methodology the Commission has required for FPL and which the Commission has required other utilities to present in their MFRs. In fact, it appears that the cost shifting that occurs from this method may be one of the "principles" used by the Company. This is suggested by Tampa Electric's request for adoption of a 12 CP and 50% AD methodology, but lack of any analysis of whether a 12CP and 50% AD methodology is consistent with cost causation on Tampa Electric's system.

As I will discuss, this production cost allocation methodology unreasonably assigns fixed generation costs to higher load factor general service demand class customers who efficiently use the Company's generating capacity at relatively consistent levels throughout the day and throughout the year, therefore helping to defray the cost of such capacity. The price signals that would be sent to customers, if the Company's recommended methodology were adopted, would be counter to the efficient use of the Company's costly generating unit resources. It links off-peak energy usage to generation resource additions. That link, of course, is contrary to logic and erroneous. Off peak use of the utility's generation resources helps defray the fixed costs of those assets that otherwise would have to be recovered from peak period use.

Q. Would you discuss the problems that you have identified with Tampa Electric's proposed 12 CP and 50% AD production demand allocation method?

A. The 12 CP and 50% AD method is essentially a 50/50 demand/energy weighted allocation method. Its proponents generally argue that energy use or system load factor impacts the economic tradeoffs among the types of generation resources selected to meet customer demands. These advocates argue that the higher cost of base load capacity is only incurred because of the fuel savings that are provided by a base load (or intermediate load) resource relative to a simple cycle combustion turbine. Thus, the 12 CP and 50% AD method can generally be thought of as a substitution of capital investment in lieu of burning higher cost fuel in peaking units. The "capital substitution" methodology is a production cost allocation method that attempts to capture the economic trade-offs between high capital cost base load (or, perhaps intermediate load) generating resources that have lower operating costs (*i.e.*, lower fuel costs/mWh due to fuel type or lower heat rates), versus lower capital cost resources (such as simple cycle combustion turbines) that have higher operating costs (*i.e.*, higher fuel costs due to use of oil or natural gas, or higher heat rates). The concept underlying the "capital substitution" method is that higher energy use creates incentives to substitute higher capital cost resources for lower capital cost resources – thus, creating a linkage between energy use and capital costs.

Q. How is the principle of "cost causation" used to develop a class cost of service analysis?

A. As described on page 38 of the NARUC Electric Utility Cost Allocation Manual, "Cost causation is a phrase referring to an attempt to determine what, or who, is causing the costs to be incurred by the utility." In order to assess each rate class' share of total jurisdictional costs, all of the Company's costs are first functionalized into the major functions provided by the utility: production, transmission, distribution and customer related costs (such as customer accounting). For example, production costs, which would include generation plant in service, depreciation reserves and other rate base related costs, depreciation expense, O&M expenses, fuel and purchased power are assigned to the production function. Once functionalized, these costs are then classified as either demand related, energy related, or customer related. Finally, the functionalized and classified costs are then allocated to rate classes based on allocation factors tied to cost causation. Fixed demand related costs are generally caused by the need for generation resources to meet peak demands; energy related costs, such as fuel expenses, are caused by the total amount of energy use of each rate class.

Q. Does Tampa Electric's testimony in this case in support of its proposed 12 CP and 50% AD method provide any substantive evidence to justify allocation of 50% of the Company's fixed production demand costs on the basis of energy?

A. No. Tampa Electric witness Ashburn simply asserts that it reflects some measure of cost responsibility, but offers no specific evidence. He also cites as support the conclusion that the increase in the percentage of average demand in the production demand allocation factor from 8% using the 12 CP and 1/13th AD method to 25% under Tampa Electric's last approved method "resulted in a reduced revenue requirement allocation to the residential and small commercial rate classes" and that the proposed increase in the percentage to 50% "will further reduce that allocation."[2] A large, if not controlling, rationale for the Company's proposal in this case appears to be the end result, which is a cost shift to large customers. But simply deciding to switch cost responsibility, without a substantive link to cost incurrence, is not supported by traditional ratemaking and is thus not a good ratemaking policy.

Q. Why is it important to perform a reasonable allocation of costs to rate classes?

A. There are a number of reasons to do so. First, economic efficiency requires that rates reflect underlying costs. For example, while one could just divide Tampa Electric's total fuel costs by the number of customers on the system and send each customer a uniform

[2] Ashburn Direct Testimony at page 33.

bill, that approach would clearly be unfair and result in a substantial misallocation of resources by overpricing energy related fuel costs to most customers and under-pricing it to higher load factor customers. Cost causation dictates that these energy related costs be assigned on the basis of the energy (kWh) use of each rate class. Similarly, fixed demand related costs, such as the return on generation plant investment and fixed production O&M are incurred by the utility to meet the peak demand of its customers. Once these plants are constructed, these demand related costs are fixed and do not vary with the amount of energy used by customers. As a result, economic efficiency is best achieved by allocating fixed demand related costs on the basis of class peak demand.

In addition to economic efficiency, a related reason for allocating costs on the basis of cost causation is to prevent cross-subsidization of one rate class by another. Cross-subsidization occurs when one set of customers pays in excess of cost and another pays less than the cost of serving that set of customers.

Tampa Electric is proposing that this Commission adopt a methodology that classifies half of all of the Company's fixed production costs as demand related, compared to the current Tampa Electric method that classifies 75% of fixed production costs as demand related, which is already 25% less than strict cost causation would dictate. Strict cost causation, absent any other evidence to the contrary, would argue for a coincident peak allocator to assign cost responsibility for fixed, demand related costs. In the case of Tampa Electric, such an allocator would be a winter CP allocator or a combined winter/summer CP allocator. At a minimum, production demand related fixed costs should be allocated on the basis of 12 CP. The Commission has adopted a 12 CP and 1/13th allocator in many prior electric utility rate cases. While this allocator does include a small energy component, the practical effect of the 12 CP and 1/13th AD allocator is very close to a 100% demand 12 CP allocation method.

Moreover, Tampa Electric already classifies the Polk Unit 1 gasifier and the Big Bend Unit 4 scrubber as 100% energy. Its new proposal in this case further moves additional fixed production demand costs (rate of return, depreciation, fixed O&M expense) to an energy allocation. This means that customer usage in off-peak hours, weekends, off-peak months are deemed to cause the Company to install additional generation resources. There is no evidence to support this assertion; rather, the evidence refutes it.

Q. What evidence refutes Tampa Electric's purported justification for allocating 50% of fixed production costs as energy-related?

A. The theory relied on by Tampa Electric --"capital substitution"-- is that higher capital cost resources are procured because of the fuel savings, and those resources benefit customers relative to basic simple cycle combustion turbines (Ashburn Direct Testimony at page 32). While it is true that the Company has a substantial amount of coal fired generation, it has had this capacity for many years. The relevant price information that should be conveyed to Tampa Electric's customers must be premised on forward looking economic decisions, not decisions that were made 20 or 30 or more years ago. Tampa Electric's most recently installed base load coal unit became commercial in 1985 and was planned in the early 1980's. Its other coal units (Big Bend 1-3) became commercial beginning in 1970.

During this period, such factors as the Fuel Use Act that precluded or discouraged the installation of gas fired generation may have had a significant impact on the decisions regarding the type of generating capacity that was added to Tampa Electric's system. The "Powerplant and Industrial Fuel Use Act" was signed into law in 1978. Its key provisions prohibited the use of natural gas or petroleum as an energy source in any new electric power plant and prohibited the construction of any new electric power plant without the capability to use coal or any alternate fuel as a primary energy source. It would make no economic sense to send price signals to Tampa Electric's customers in 2014, based on economic relationships and/or government policies that existed 44 years ago but which are vastly different today.

Based on Tampa Electric's recently filed 10-Year Site Plan, the Company is planning on a combination of Combined Cycle Gas Turbines ("CCGT") and simple cycle Combustion Turbines ("CT") as feasible generation resource additions in the future. This is consistent with my experience for other utilities throughout the U.S., including FPL. With environmental restrictions (in particular the Environmental Protection Agency ("EPA") Green House Gas New Source Performance Standards for Coal Units rulemaking) and lower natural gas prices, new coal fired power plants are not economic compared to CCGT and CT resources. To test the reasonableness of Mr. Ashburn's testimony in support of Tampa Electric's recommended 12 CP and 50% AD method, I developed a set of screening curves that evaluate the relative economics of a higher cost CCGT compared to a CT.

Q. Would you describe the specific analysis that you developed?

A. Table 1 below summarizes CCGT and CT costs based on the U.S. Department of Energy, Energy Information Administration ("EIA") Annual Energy Outlook forecast for 2013 ("AEO 2013"). This forecast, which is prepared annually by EIA, provides projections of a significant number of energy industry metrics, including the U.S. electric utility industry. As part of its forecast, EIA prepares a set of assumptions that are incorporated into its models. Among these assumptions are a set of capital and operating costs for CCGT and CT generation resources. The data summarized in Table 1 is contained in EIA's January 2013 report entitled "Levelized Cost of New Generation Resources" in the Annual Energy Outlook 2013. Baron Exhibit__(SJB-2) contains an excerpt from this report.

Table 1
U.S. Average Levelized Costs (2011 $/mWh) - C/O Date: 2018*

	Conventional Combined Cycle	Advanced Combustion Turbine
Capacity Factor	87.0%	30.0%
Capital	15.8	30.4
Fixed O&M	1.7	2.6
Var O&M + Fuel	48.4	68.2
Total	65.9	101.2
Total Capital Cost/mW	$ 120,415	$ 79,891
Fixed O&M/mW	$ 12,956	$ 6,833
Total Fixed Cost/mW	$ 133,371	$ 86,724
Total Variable Cost/mWh	$ 48.40	$ 68.20

*Source: Energy Information Administration Annual Energy Outlook 2013, "Levelized Cost of New Generation Resources."

The cost data presented in Table 1, as noted in the table, are levelized $2011 costs for a

Conventional CCGT and an Advance CT, both with a commercial operation date of 2018. This comparison provides a reasonable estimate of the economic trade-offs between lower and higher capital cost resources. As shown in the table, the annual levelized fixed cost of a conventional CCGT is $133/kW, while for an Advanced CT the annual levelized fixed cost is $87/kW. The variable operating costs of the two resources are $48/mWh and $68/mWh respectively. Using this information, a screening curve comparison can be developed to identify the breakeven capacity factor or "hours use" of a kW of capacity between the two resources. A screening curve is a cost curve for the resource, reflecting both fixed costs (capital, O&M expense) and variable costs (fuel, variable O&M expense) at various capacity factor (hours use) levels. It is designed to compare the cost of alternative resources at different usage levels. Table 2 shows the resulting all-in levelized costs at various capacity factors.[3]

[3] The EIA data is presented in terms of constant dollar ($2011) levelized costs for ease of comparison.

Table 2
Screening Curve Analysis: CCGT vs. CT

Capacity Factor	mWh	Total Busbar Cost CCGT	Total Busbar Cost CT
4.0%	350	$ 429.03	$ 315.70
5.0%	438	$ 352.90	$ 266.20
10.0%	876	$ 200.65	$ 167.20
15.0%	1,314	$ 149.90	$ 134.20
20.0%	1,752	$ 124.53	$ 117.70
26.8%	2,348	$ 105.21	$ 105.14
30.0%	2,628	$ 99.15	$ 101.20
35.0%	3,066	$ 91.90	$ 96.49
40.0%	3,504	$ 86.46	$ 92.95
45.0%	3,942	$ 82.23	$ 90.20
50.0%	4,380	$ 78.85	$ 88.00
55.0%	4,818	$ 76.08	$ 86.20
60.0%	5,256	$ 73.78	$ 84.70
65.0%	5,694	$ 71.82	$ 83.43
70.0%	6,132	$ 70.15	$ 82.34
75.0%	6,570	$ 68.70	$ 81.40
80.0%	7,008	$ 67.43	$ 80.58
85.0%	7,446	$ 66.31	$ 79.85
90.0%	7,884	$ 65.32	$ 79.20
95.0%	8,322	$ 64.43	$ 78.62
100.0%	8,760	$ 63.63	$ 78.10

For example, the CCGT resource has a $2011 levelized total cost of $78.85 at a 50% capacity factor. This means that the CCGT would cost $78.85 per kW if it were operated for 4,380 hours per year. The CT cost, at the same 4,380 hour of operation would cost $88.00 per kW.

As shown in Table 2, the breakeven hours-use of the conventional CCGT and the advanced CT occurs at a capacity factor of 26.8%, which correlates with 2,348 hours of usage during the year. For operation at 2,348 hours or below, the CT is less costly, while for operation above 2,348 hours, the CCGT is less costly due to its lower heat rate (btu/kWh).

Q. What are the cost of service implications of this screening curve analysis with regard to the 12 CP and 50% AD methodology?

A. The screening curve economic comparison shows that beyond 2,348 hours of annual operation (27% of the hours of the year), the CCGT is less expensive and would be selected as the least cost resource. As long as the system's energy needs required the generation resource to operate at least 2,348 hours during the year, the least cost resource is the CCGT. Energy usage beyond 2,348 mWh per mW has no impact on the economic decision to select the higher capital cost CCGT resource (over the lower capital cost CT). Thus, from a cost of service/cost responsibility standpoint, any energy usage in hours greater than the top 2,348 peak hours during the year do not "cause" the higher capital costs of the CCGT resource (compared to the CT). Translating this into a class cost responsibility framework, energy usage in the remaining 6,432 hours during the year does not impose any additional capital costs on the system. This result is particularly important in assessing the reasonableness of the Company's proposed 12 CP and 50% AD method, which assigns fixed generation resource costs to rate classes on the basis of the classes' average demand during all 8,760 hours of the year. The screening curve economic analysis shows that energy usage in the 6,432 hours beyond the breakeven hours (2,348) is not responsible for any additional CCGT capacity costs (*i.e.*, those CCGT capital costs in excess of CT capital costs). Assigning 50% of all Tampa Electric fixed generation costs on the basis of class average demand, based on a theory that customers with higher load factors are causing these higher CCGT costs to be incurred, is contrary to the economic evidence of cost responsibility that shows that kWh energy usage in excess of a system-wide 26.8% load factor does not influence the decision concerning what type of generating unit to install. Perhaps that is why the Company does not base its request for use of the 12CP and 50% AD methodology on a cost causation analysis.

Q. **Is there additional evidence that shows that larger customers with higher load factors, such as those that take service under the GSD rate schedule, do not cause the incurrence of the excess CCGT costs in proportion to their annual energy usage?**

A. Yes. That is evident when one examines consumption patterns during the months that experience the highest load hours of the year as compared to the consumption patterns in other months.

Q. **In which months of the year do the highest 2,348 load hours occur?**

A. Using the hourly loads provided by Tampa Electric in response to The Florida Industrial Users Group First Set of Production of Documents request No. 3, I analyzed Tampa Electric's projected 2014 load data. Based on this analysis, the highest 2,348 hourly loads of the Company occur primarily in the summer months. Table 3 summarizes these results, together with the percentage share of energy usage for the residential class and for rate schedule GSD each month.

Table 3
Distribution of Highest 2,348 Load Hours
Test Year 2014

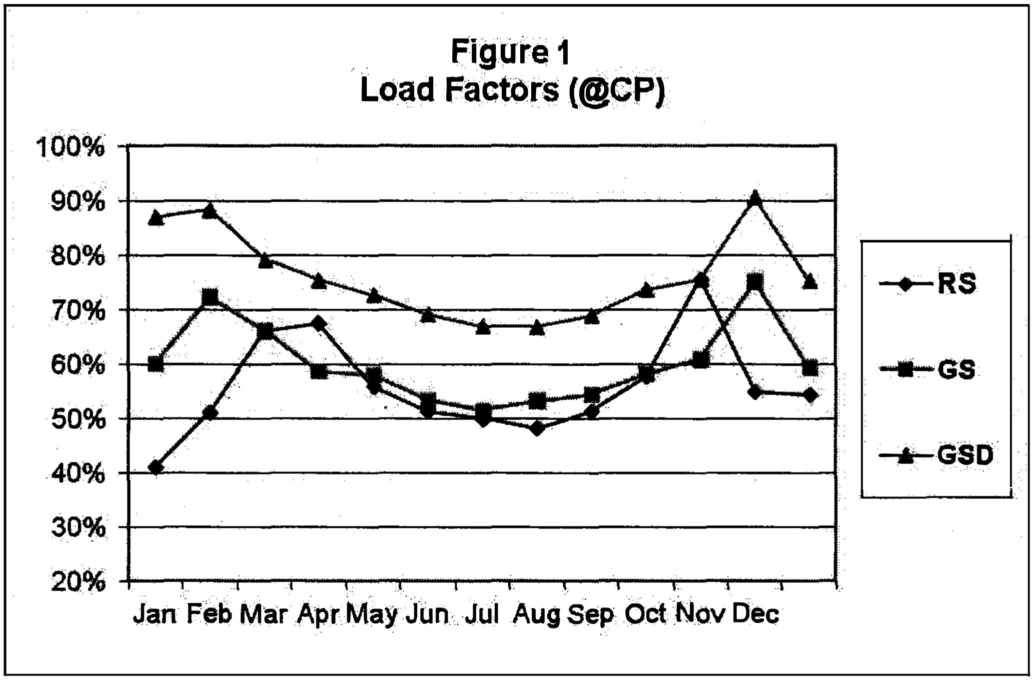
		Distribution of Sales	
Month	# of Hours	RS	GSD
Jan	80	8.2%	7.7%
Feb	35	7.0%	7.3%
Mar	45	6.4%	7.4%
Apr	108	6.5%	7.8%
May	267	7.7%	8.2%
Jun	373	9.8%	9.1%
Jul	379	10.5%	9.2%
Aug	372	10.4%	9.1%
Sep	359	10.7%	9.5%
Oct	232	8.8%	8.8%
Nov	52	7.0%	8.1%
Dec	46	6.9%	7.9%
Total	2,348	100.0%	100.0%
% Jun-Sep	63.2%	41.5%	36.8%

As can be seen in the table, the majority of the "highest load hours" occur during the summer months of June through September (63% of these high load hours occur in this period). Because rate schedule GSD has a flatter annual usage pattern over the year (due to its higher than average load factor), GSD consumes a relatively lower proportion of its energy in the summer months, compared to the residential class. Stated differently, the swing in percentages between the highest and lowest months for residential customers (*i.e.*, 10.7 -6.4 = 4.3 percentage points) is nearly twice as large as that experienced in serving GSD (*i.e.*, 9.5 – 7.3 = 2.3 percentage points). It is also very important to recognize that these percentages for rates Residential ("RS") and GSD summarize the total mWh during each month and do not differentiate between on-peak hours (when the highest loads occur) and off-peak hours. Most of the 2,348 hours that comprise the highest load hours occur during the four-month period from June through September.[4] While I do not have the breakdown of mWh usage by rate class on a monthly on-peak/off-peak basis, it seems reasonable to conclude consistent with the data set forth in Table 3, that a higher load factor rate class, such as GSD, would have a smaller proportion of its monthly usage during the June through September period.[5] This means that GSD's responsibility for load during the highest 2,348 hours of the year is likely to be much smaller than its overall percentage of energy use during each month.

Figure 1 contains an excerpt from the Company's workpapers that shows monthly coincident peak load factors for the residential, General Service Non-Demand ("GS") and GSD rate classes.

[4] While Tampa Electric is a traditionally winter peaking utility, there are many more high load hours during the summer months than during the winter months. The winter peaks tend to be short duration peaks driven by extreme weather, while the summer peaks are more extensive in duration.

[5] At an extreme of 100% load factor, the percentage of a rate class would have the same hourly mWh each hour of the month. In this case, the percentage of monthly on-peak energy use is exactly the percentage of the number of on-peak hours during the month. For example, in July, the number of on-peak hours using a typical "5 X 16" weekday period would be about 49%.

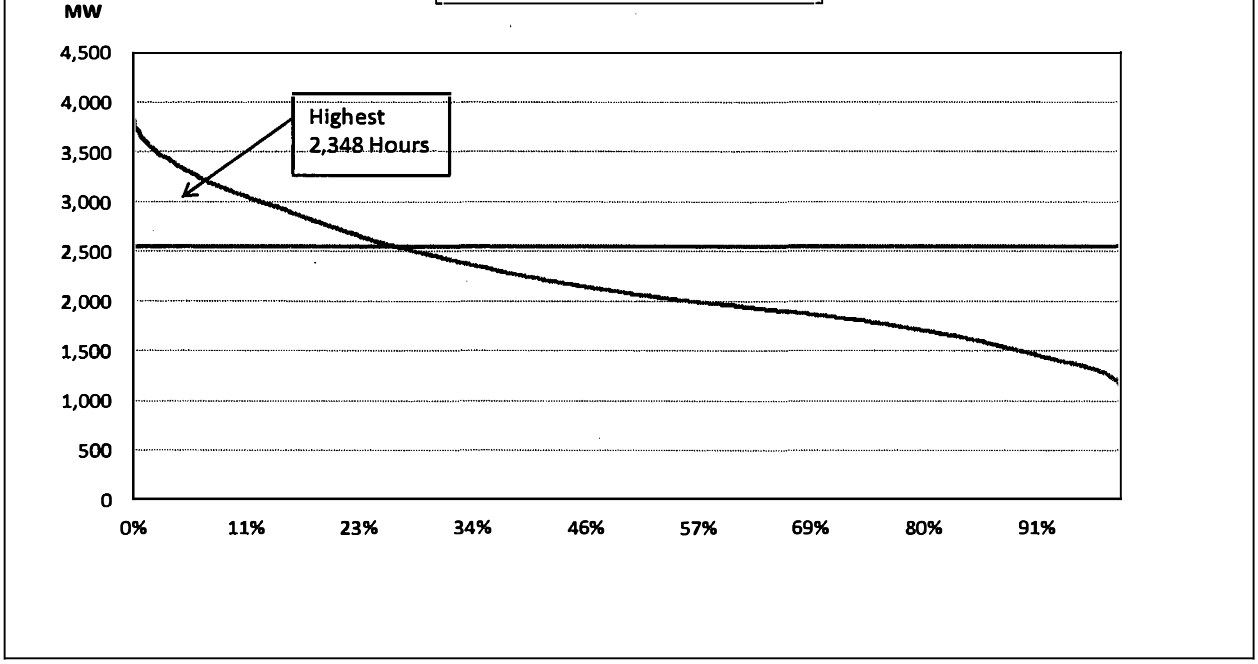


This confirms that the GSD class has higher monthly load factors, which means that the GSD class has a higher percentage of its monthly energy use relative to the RS and GS classes occurring in the months of October through May. As a result, the need for generating capacity to serve the significant loads that occur from June through September is caused to a large degree by the RS and GS rate classes, not GSD. Moreover, it is the extended duration of the need for that capacity that drives the decision to install CCGT, rather than CT, capacity.

Q. Do you have any additional evidence to support your contention that the RS and GS rate classes drive the need for CCGT, rather than CT, technology?

A. Yes. Figure 2 below shows Tampa Electric's projected 2014 annual load duration curve using this same hourly load data. The data representing the highest 2,348 hours of load clearly demonstrate that only a small portion of the total annual energy usage by customers impacts the resource economics trade-off decision.

Figure 2
TECO 2014 Load Duration Curve



Q. Do these results demonstrate that using annual energy ("AD") in the Company's 12 CP and 50% AD method improperly allocates cost?

A. Yes. Because only energy usage during the highest 2,348 load hours of the year are relevant to generation resource trade-offs (*i.e.*, the trade-off discussed by Mr. Ashburn at page 32 of his testimony between high capital cost/low operating cost units and low capital cost/high operating cost units), <u>and</u> the fact that the higher load factor GSD customer class has a lower share of this energy, the 50% AD method is incorrect. If a 50% energy component is to be used, it should only be based on each class's share of energy during the top 2,348 hours of the year. In addition, if such a method were to be adopted, the "demand" portion of the allocator should only be the peak month CP or perhaps the summer and winter peak month CPs, not CP demands in all 12 months. As a result, I could support a single CP or winter/summer CP methodology to allocate the fixed costs of production plant, or an alternative methodology that allocates the fixed costs strictly on a demand basis. In any event, based on my analysis, I believe a 12 CP and $1/13^{th}$ AD allocator would be far superior to the 12 CP and 50% AD methodology that Tampa Electric has proposed. Because the use of 12 CPs captures rate class usage during the 12 monthly peaks, plus the additional 1/13 energy (AD) component reflecting annual energy usage, this methodology, while still creating some subsidization by GSD customers, does a better job of capturing each rate class's cost responsibility for Tampa Electric's fixed production costs than Tampa Electric's proposed 12 CP and 50% AD methodology.

Q. Have you performed any additional analyses that demonstrate the unreasonableness of Tampa Electric's proposal?

A. Yes. Using the same EIA levelized cost data from the AEO 2013 forecast, I developed a screening curve analysis that compares a Conventional CCGT with a Conventional CT. The Conventional CT has somewhat different cost characteristics than the Advanced CT that I used in the screening curve analysis that I presented in Tables 1 and 2. Tables 4 and 5 summarize this analysis.

Table 4
U.S. Average Levelized Costs (2011 $/mWh) - C/O Date: 2018*

	Conventional Combined Cycle	Conventional Combustion Turbine
Capacity Factor	87.0%	30.0%
Capital	15.8	44.2
Fixed O&M	1.7	2.7
Var O&M + Fuel	48.4	80
Total	65.9	126.9
Total Capital Cost/mW	$ 120,415	$ 116,158
Fixed O&M/mW	$ 12,956	$ 7,096
Total Fixed Cost/mW	$ 133,371	$ 123,253
Total Variable Cost/mWh	$ 48.40	$ 80.00

*Source: Energy Information Administration Annual Energy Outlook 2013, "Levelized Cost of New Generation Resources."

Table 5
Screening Curve Analysis: CCGT vs. CT

Capacity Factor	mWh	Total Busbar Cost CCGT	CT
3.7%	320	$ 465.52	$ 465.48
5.0%	438	$ 352.90	$ 361.40
10.0%	876	$ 200.65	$ 220.70
15.0%	1,314	$ 149.90	$ 173.80
20.0%	1,752	$ 124.53	$ 150.35
26.8%	2,348	$ 105.21	$ 132.50
30.0%	2,628	$ 99.15	$ 126.90
35.0%	3,066	$ 91.90	$ 120.20
40.0%	3,504	$ 86.46	$ 115.18
45.0%	3,942	$ 82.23	$ 111.27
50.0%	4,380	$ 78.85	$ 108.14
55.0%	4,818	$ 76.08	$ 105.58
60.0%	5,256	$ 73.78	$ 103.45
65.0%	5,694	$ 71.82	$ 101.65
70.0%	6,132	$ 70.15	$ 100.10
75.0%	6,570	$ 68.70	$ 98.76
80.0%	7,008	$ 67.43	$ 97.59
85.0%	7,446	$ 66.31	$ 96.55
90.0%	7,884	$ 65.32	$ 95.63
95.0%	8,322	$ 64.43	$ 94.81
100.0%	8,760	$ 63.63	$ 94.07

Based on this screening curve analysis, the breakeven hours use at which the CCGT becomes less expensive than the CT is 320 hours. Essentially, the CT is only the economic choice for a narrow peak window (such as a weather spike driven winter peak). The conclusion from this analysis is that only energy use in the highest 320 hours of load during the year impact the decision to incur the higher cost of an intermediate CCGT resource. Energy use during the remaining 8,440 hours of the year have no bearing on this economic decision and thus would not be a cost causative factor for the incurrence of fixed production demand costs.

Q. Based on your analysis, should the Commission adopt Tampa Electric's proposal to use a 12 CP and 50% AD method?

A. No. There is no basis for the Company's proposal. It simply results in a substantial cost shift from the RS and GS rate classes to larger customers.

Q. Should the Commission adopt Tampa Electric's current 12 CP and 25% AD method in this case?

A. No. First, the Company has not presented such a study in this case. More importantly, the 12 CP and 25% AD suffers from the same problems that I have identified for the 12 CP and 50% AD method, just not as severely. Nonetheless, there is no reasonable basis for the 12 CP and 25% AD method. Rather, based on the Commission's preference for the 12 CP and 1/13th AD methodology that it approved in numerous cases for FPL over the years (at least since 1983) and other Florida electric utilities, I recommend that the Commission adopt the 12 CP and 1/13th AD for Tampa Electric as well. In a subsequent section of my testimony, I will present a 12 CP and 1/13th AD method that also incorporates Tampa Electric's MDS distribution cost allocation analysis.

Q. Does the Tampa Electric system's generation resource mix (capacity mix) justify the 12 CP and 50% AD methodology, or even the 12 CP and 25% AD method?

A. No. Based on data from the 2013 10-Year Site Plans filed by FPL and Tampa Electric, the Base/Intermediate load generation capacity mixes of the two utilities are about the same (79% for Tampa Electric, 71% for FPL). The Commission has consistently (at least since 1983) found that the 12 CP and 1/13th AD method is appropriate for FPL. Based on the composition of generation resources, this cost allocation methodology is also appropriate for Tampa Electric.

Q. Would you please discuss Tampa Electric's proposal to use a Minimum Distribution System methodology to classify and allocate distribution plant investment and expenses to retail rate classes?

A. Yes. As discussed in Tampa Electric witness William Ashburn's testimony, the Company is proposing to utilize an MDS methodology to classify a portion of distribution plant and expenses as both demand related and customer related using a generally accepted method to identify the demand and customer components of FERC distribution plant accounts 364 (poles), accounts 365 to 367 (overhead and underground conductors and conduit) and account 368 (transformers). Tampa Electric previously classified 100% of these distribution costs as demand related. I fully support the Company's proposed MDS recommendation in this case and believe that it is a valid, proper and reasonable approach for use in the class cost of service study.

Q. What is the basis, from a cost causation perspective, to classify these distribution costs as both demand and customer related?

A. As described in the NARUC Electric Utility Cost Allocation Manual, the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer.[6] The amount of

[6] An excerpt from the NARUC manual that discusses the classification of distribution costs is contained in Baron Exhibit__(SJB-3).

distribution cost that is a function of the requirement to interconnect the customer, regardless of the customer's size, is appropriately assigned to rate classes on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?

A. As discussed in the NARUC cost allocation manual, there are two approaches that are typically used to develop a customer component of distribution plant and expenses. Each methodology ("zero-intercept" and "minimum size") attempts to measure the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers, etc.). Each of the two methods is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Essentially, the "minimum size methodology" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost, which is not related to customer usage levels, that is used to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. For example, new distribution investment in poles, or underground conductors, for a new subdivision may be associated with unsold, or unoccupied homes that have "0" kW demand – yet the cost for these facilities is still incurred. Similarly, distribution facilities must be installed to meet the needs of part time residents that may have little or no demand during a portion of the year – yet the cost of such distribution facilities still must be incurred and does not vary as a result of the fact that such facilities serve part-time residents. The MDS methodology gives recognition to this circumstance by assigning a portion of the cost of these facilities based on the existence of a "customer," and not just the level of the customer's kW demand.

Q. Do other major electric utility operations in Florida incorporate minimum distribution system classifications in class cost of service studies?

A. Yes. In a recent Gulf Power Company ("GPC") rate case (Docket No. 110138-EI), GPC presented and strongly supported the use of an MDS methodology to develop its class cost of service study. GPC's cost of service witness in that case, Michael O'Sheasy, testified in support of an MDS methodology as follows:

> Q. Please explain why the Minimum Distribution System methodology is important to Gulf and its customers?
>
> A. As I discuss in more detail later, some costs of the distribution system beyond the customer meter and service drop do not vary with customers' use of electricity. The Minimum Distribution System (MDS) methodology is necessary to accurately determine and allocate these customer-related distribution costs. The misclassification of costs that results from not using the MDS methodology sends misleading price signals to customers.

> This misclassification also results in different customer rate classes bearing more or less costs than their cost-causative share of distribution costs. It is therefore important to examine these customer-related costs and classify them appropriately, which the MDS methodology enable us to do. [O'Sheasy Direct Testimony at pages 16 -17, Gulf Power Company Docket No. 110138-EI].

Q. Do you agree with Mr. O'Sheasy's quoted testimony on the MDS issue?

A. Yes. There is no question that some portion of each of Tampa Electric's distribution accounts 364 to 368 is customer related. If a Tampa Electric customer were to decrease its usage to 0 kW, all of the poles, overhead conductors, underground conductors and transformers would <u>not</u> somehow disappear or be used to supply customers in other parts of the system. An MDS methodology recognizes this and reasonably reflects it in the Company's class cost of service study.

Q. Did the Commission adopt GPC's MDS methodology in Docket No. 110138-EI?

A. It is my understanding, based on a review of the Commission's Order in that case, that the Commission approved a Stipulation adopting the methodology "solely for use in designing rates in this case." At least for that GPC case, the conceptual framework that some portion of distribution accounts 364 through 368 is customer related has been accepted, even if it is only for "use in designing rates" in that case.

Q. How do Tampa Electric's MDS results compare to the MDS classifications developed by GPC?

A. As reported by Mr. Ashburn, Tampa Electric's analysis classifies 64% of poles, 9% of conductors and 24% of transformers as customer related. GPC's analysis of its distribution plant costs produced very similar results. Table 6 summarizes the comparison.

Table 6
Comparison of TECO and Gulf Power Company MDS Results

		TECO		Gulf Power Company	
Account	Description	% Cust	% Dem	% Cust	% Dem
364	Poles	64%	36%	65%	35%
365, 366,367	Conductors	9%	91%	8% *	92%
368	Transformers	24%	76%	25%	75%

* GPC % weighted by TECO plant-in-service for accounts 365 to 367.

Q. Have regulatory commissions in other states adopted the minimum distribution system method?

A. Yes. While I have not conducted a comprehensive study, a number of commissions have authorized the MDS methodology. Jurisdictions authorizing the MDS method for utilities in their states that I am specifically familiar with include: Wisconsin, Pennsylvania, Kentucky, Virginia, Georgia, and Ohio.

Q. Do you believe that a minimum distribution system is appropriate for Tampa Electric?

A. Yes. Given the importance of the cost of service results (parities) in setting rates, it is reasonable and appropriate for the Commission to adopt Tampa Electric's proposed MDS methodology. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities are needed to interconnect a customer to the Tampa Electric system, including meeting minimum safety standards set forth in the National Electric Safety Code ("NESC"), which the Commission requires be adhered to for all Florida electric utilities.

Q. Have you developed a 12 CP and 1/13th AD cost of service study that incorporates Tampa Electric's MDS study to classify and allocate distribution costs?

A. Yes. Using the Company's cost of service model, I modified Tampa Electric's filed 12 CP and 1/13th AD cost of service study to include the MDS analysis that Tampa Electric developed for its recommended 12 CP and 50% AD method. Baron Exhibit__(SJB-4) contains a summary of this study. Table 7 summarizes the rate class rates of return and parities for this study and compares these results to the Company's 12 CP and 50% AD study, under current rates. It shows that when each rate class' contribution to the Company's return is measured in relation to each class' contribution to the Company's incurrence of costs, it is clear that the GSD rate class has been substantially over-contributing to Tampa Electric's return, and the RS class has been substantially undercontributing.

Table 7
Cost of Service Results with MDS
@ Present Rate Revenues During Test Year Before Increase*

	12CP & 1/13th		12CP & 50%	
	ROR	Index	ROR	Index
RS	4.10%	0.85	4.43%	0.92
GS	4.67%	0.97	4.84%	1.00
GSD	5.49%	1.14	5.06%	1.05
IS	9.95%	2.06	7.43%	1.54
LS ENERGY	6.42%	1.33	2.39%	0.49
LS FACILITIES	8.96%	1.85	8.96%	1.85
Total	4.84%	1.00	4.84%	1.00

*These ROR Parity results reflect the revenues paid by each customer class at present rate levels, before the requested TECO rate increases, under the Company's proposed COS method compared to the HUA proposed 12 CP & 1/13th AD + MDS method.

Q. **To the extent that Mr. Ashburn, at page 34, lines 3 through 8 of his testimony, is arguing that the MDS methodology should only be adopted by the Commission if the Company's preferred 12 CP and 50% AD method is also adopted, would there be any basis to link these two methodologies in that manner?**

A. No. First, the two methodologies are independent; the 12 CP and 50% AD method is associated with the allocation of fixed production costs, while the MDS method is used to allocate the cost of distribution facilities. Second, linking the two methodologies defies any concept of "principle" underlying the adoption of a class cost of service study. This rationale seems to be driven exclusively by the outcome of the cost allocation study, not its underlying reasonableness or how well it reflects cost causation.

Q. Has the Company provided any additional clarification to Mr. Ashburn's testimony on the appropriateness of employing the MDS methodology with the 12 CP and 1/13th AD or other production demand cost allocation methodologies?

A. Yes. In its response to HUA's First Set of Interrogatories, Interrogatory No. 90, Mr. Ashburn confirms that he did not intend to state that the MDS methodology should only be employed if the 12 CP and 50% AD method is adopted. Baron Exhibit__(SJB-5) contains a copy of this interrogatory response.

III. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE

Q. Have you reviewed Tampa Electric's proposed allocation of its requested $133.645 million revenue increase to rate classes?

A. Yes. Tampa Electric's analysis is presented in Mr. Ashburn's Exhibit__(WRA-1), Document No. 2. The allocation of the Company's requested increase follows the results of its recommended 12 CP and 50% AD + MDS cost of service study, such that each rate class is assigned an increase that Tampa Electric calculates would bring that rate class to parity with the System average rate of return, subject to two limitations: no class should receive a rate decrease and no class should receive an increase greater than 1.5 times the average increase. Based on Tampa Electric's preferred cost of service study, only the lighting class increase is impacted by the limitations.

Q. Do you agree with Tampa Electric's general methodology to assign rate class increases in this case?

A. Yes. However, since I am recommending an alternative cost of service study using the 12 CP and $1/13^{th}$ AD + MDS methodology, I have revised Tampa Electric's revenue allocation using the cost of service study results shown in my Exhibit__(SJB-4). Baron Exhibit__(SJB-6) contains the results of this revenue allocation analysis, which allocates the overall revenue increase to bring each rate class to a parity of 1.0, subject to a limitation that no rate class receives a decrease and that no class receives an increase greater than 1.5 times the retail average increase. The analysis shown in Exhibit__(SJB-6) compares Tampa Electric's proposed revenue responsibility to that proposed by HUA, inclusive of HUA's recommended revenue requirement adjustments presented by Mr. Kollen. Table 8 below summarizes these increases.[7]

[7] The HUA revenue requirement adjustments presented by Mr. Kollen have been applied to Tampa Electric's requested $133.645 million rate schedule increases. HUA has not taken a position on Tampa Electric's proposed $1.194 million increase in service charges, which has not been adjusted.

Table 8
Proposed Revenue Responsibility

Rate Class	TECO Proposed Increase Increase $	TECO Proposed Increase % Present Base Rev.	HUA Proposed Increase Increase $	HUA Proposed Increase % Present Base Rev.	Difference (HUA vs. TECO) Increase $	Difference (HUA vs. TECO) % Present Base Rev.
Residential (RS,RSVP) General Service Non-Demand (GS,TS)	$ 94,742	17.30%	$ 24,480	4.47%	$ (70,262)	-12.83%
General Service Demand (GSD, SBF) Interruptible Service (IS)	$ 37,168	11.64%	$ 4,951	1.55%	$ (32,217)	-10.09%
Lighting (LS-1)						
A. - Energy	$ 1,737	31.78%	$ 22	0.40%	$ (1,716)	-31.38%
B. - Facilities	$ -	0.00%	$ -	0.00%	$ -	0.00%
Total	$ 133,647	14.72%	$ 29,452	3.24%	$(104,195)	-11.48%

Q. Under your proposal, the GSD rate class would obtain a greater reduction in rates, relative to Tampa Electric's proposal than would be obtained by the RS and GS rate classes. Why is this occurring?

A. That result is a consequence of moving each rate class closer to parity, which is the widely accepted goal in performing class cost of service/revenue apportionment analyses. That consequence also is not surprising in light of the class cost of service results that I presented in Table 7.

Q. Are you recommending the apportionment of the Commission approved revenue

increase to rate classes based on the contribution to Tampa Electric's cost of service shown for each class in your Table 8?

A. Yes, with the caveat that these increases are based on HUA's recommended revenue requirement adjustments presented in the testimony of Mr. Kollen and Mr. Baudino. As summarized in Mr. Kollen's testimony, HUA is recommending that Tampa Electric be awarded an overall revenue increase in this case of no more than \$30.6 million. I recommend that the approved increase be allocated using the results of a compliance cost of service study based on the 12 CP and 1/13th AD + MDS methodology that I am recommending in this case. In the alternative, I recommend that the approved increase be allocated proportionately to the HUA increases shown in Table 8.

IV. RATE DESIGN ISSUES

Q. Have you reviewed Tampa Electric's proposed GSD/GSDT rate design?

A. Yes. The Company is proposing a number of increases and decreases to various GSD and GSDT rate elements (customer, energy and demand charges) to recover its recommended GSD rate class increase. Table 9 below summarizes the increases proposed for GSDT.

Table 9
TECO Proposed GSDT Rate Design

Charge	Present	Proposed	Unit Cost	% Increase
T-O-D				
Secondary	$ 57.00	$ 30.00	$ 28.21	-47.4%
Primary	$ 130.00	$ 130.00	$ 126.56	0.0%
Subtransmission	$ 930.00	$ 990.00	$ 987.60	6.5%
Demand Charge - $ per kW				
T-O-D				
Base	$ 2.84	$ 3.23	$ 3.31	13.7%
Peak	$ 5.57	$ 6.27		12.6%
Energy Charge - $ per MWh				
T-O-D				
On-Peak	$ 28.98	$ 39.99		38.0%
Off-Peak	$ 10.46	$ 9.60	$ 9.60	-8.2%

The overall base rate increase proposed for rate GSDT is about 13.5%. However, the Company is proposing a 38% increase to the GSDT on-peak (non-fuel) energy charge, which is substantially above the unit cost of service ($39.99/mWh vs. $9.6/mWh). There is no unit cost of service difference associated with non-fuel variable cost between the on-peak and off-peak periods. Therefore, the unit energy cost for the on-peak period is also $9.6/mWh.

Q. What process did Tampa Electric use to develop its GSD and GSDT rate design?

A. According to the Company's workpapers, Tampa Electric designed GSD and GSDT jointly by first increasing the GSD demand charge by the overall GSD rate class increase, setting the off-peak GSDT demand charge at unit cost and then calculating the on-peak GSDT demand charge by taking the difference between the GSD demand charge and the GSDT off-peak demand charge. For the energy charges, the Company determined the GSD energy charge as the residual necessary to produce the GSD target revenues. The GSDT energy charges were developed jointly with the GSD energy charge by setting the off-peak energy charge to unit cost of service and the on-peak GSDT energy charge using test year on and off-peak GSDT energy ratios.

Q. Do you believe that the Company's GSD/GSDT rate design is reasonable?

A. No. As I noted, the proposed on-peak GSDT energy charge is more than 4 times larger than unit cost of service, which does not reflect any on/off-peak differentials. Because the GSDT energy charge represents non-fuel energy costs, there is no basis to impose such a large differential between the on and off-peak energy charges. A more reasonable approach in this case is to set the off-peak GSDT energy charge at unit cost, impose no increase to the already excessive on-peak GSDT energy charge and then solve for the remaining revenue requirements for rate GSD/GSDT by adjusting the on-peak demand charge (the off-peak demand charge is appropriately being set at unit cost in Tampa Electric's proposed rate, which is reasonable). Baron Exhibit__(SJB-7) summarizes my recommended rate design using this approach. This methodology, which is revenue neutral within the GSD/GSDT/SBFT rate class, places a higher priority on setting the energy charges at unit cost of service (or, in the case of the on-peak GSDT energy charge, moving towards cost of service) and then uses the demand charges as a residual to meet the overall GSD rate class revenue target.

Q. Does that complete your prepared testimony?

A. Yes.

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than thirty years, both as a consultant and as an employee. Since 1986, I have been a consultant with Kennedy and Associates, providing services to consumers of utility services and state and local government agencies in the areas of utility planning, ratemaking, accounting, taxes, financial reporting, financing and management decision-making. From 1983 to 1986, I was a consultant with

Energy Management Associates, providing services to investor and consumer owned utility companies in the areas of planning, financial reporting, financing, ratemaking and management decision-making. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions providing services in the areas of planning, accounting, financial and statistical reporting and taxes.

I have appeared as an expert witness on utility planning, ratemaking, accounting, reporting, financing, and tax issues before state and federal regulatory commissions and courts on nearly two hundred occasions. In many of those proceedings, I have represented state and local ratemaking agencies or their Staffs, including the Louisiana Public Service Commission, Georgia Public Service Commission and various groups of Cities with original rate jurisdiction in Texas. I also have appeared before the Florida Public Service Commission ("Commission") in numerous proceedings, including the four most recent Florida Power & Light Company base rate proceedings in Docket Nos. 120015-EI (2012), 080677-EI (2009), 050045-EI (2005), and 001148-EI (2002). I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. **On whose behalf are your testifying?**

A. I am providing testimony on behalf of the WCF Hospital Utility Alliance ("HUA"), a group of hospitals and healthcare facilities that take electric utility service from Tampa Electric Company (the "Company").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) address and make recommendations regarding the operation and maintenance ("O&M") expense included in the Company's claimed revenue requirement, 2) quantify the effect of an adjustment to the other revenue included in the Company's claimed revenue requirement, and 3) quantify the effect of HUA witness Mr. Richard Baudino's return on equity recommendation on the Company's claimed revenue requirement.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's claimed revenue requirement by $40.898 million to reflect a reduction in O&M expense to a just and reasonable amount. From a "top-down" perspective, the Company's request is excessive and represents an 18.4% increase over 2012, the most recent year for which actual amounts are available. The Company's request reflects a wish list of increased spending and is not justified by the present economic realities or by the expansion of service or work-scope activities. After its last base rate case in 2009, the Company initially reduced its O&M expense in 2010 and then carefully and successfully managed it through 2012 so that there essentially was no growth over that sustained period. The Company did so by implementing more efficient processes and investing in new systems to offset the effects of inflation and other growth drivers.[1] The Commission should direct the Company to continue this approach and limit any increase in O&M expense since 2012 to 4.7%, or a 2.3% annual growth rate to reflect the net effects of inflation, offset by the Company's

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1 The costs of these investments and the investments that will be incurred in 2013 and 2014 are included in the Company's rate base in this proceeding and should continue to reap savings as well as allow the Company to achieve additional savings.

continuing and additional efficiency improvements, and to reflect limited growth in the expansion of work-scope requirements due primarily to government regulations.

I also address specific "bottoms-up" adjustments to the Company's proposed O&M expense in further support of my recommendation to limit the increase in O&M expense from a top-down perspective. More specifically, the following adjustments would be appropriate under a "bottoms-up" approach:

Summary of HUA Issue-Specific O&M Expense Reductions
($ Million)

Reduce Big Bend Planned Maintenance Outage Expense to Reflect Historic Levels	$7.145
Reduce Distribution Operation and Maintenance Expense to Reflect Historic Levels	5.317
Reject Increase in Performance Sharing Plan Incentive Compensation	5.304
Reject Stock Compensation Expense	5.084
Normalize Injuries and Damages Expense to Reflect Recent Historic Levels	1.728
Reduce Affiliate Charges in to Reflect TECO Energy Acq of New Mexico Gas Co.	2.900
Reduce Proposed Increase in Call Center Expense	1.575
Eliminate Proposed Increase in Uncollectible Accounts Expense	1.302
Reduce Proposed Increase in Legal Expenses	1.521
Sum of HUA Issue-Specific Recommendations	$31.876

In addition to my recommended reduction in O&M expense, I recommend that the Commission increase other revenues by $4.920 million to reflect the fact that Calpine recently notified the Company of its intent to rollover a portion of its transmission load under the Company's Open Access Transmission Tariff ("OATT"). The Company incorrectly assumed that the Calpine load would be terminated in its filing.

Finally, I quantify the effect of Mr. Baudino's 9.3% return on equity recommendation compared to the Company's request for an 11.25% return on equity. The effect is a reduction in the Company's claimed revenue deficiency of

$58.375 million, assuming no adjustments to rate base or adjustments to the Company's proposed capital structure. Each 1.0% return on equity is equivalent to $29.936 million in the base revenue requirement, again, assuming no adjustments to rate base or capital structure. I also describe the additional effects of the return on equity on various clause revenue recoveries and on the cost of plant included in rate base and the related depreciation expense.

I address each of these issues in more detail in the same sequence that I summarized my recommendations.

II. O&M EXPENSE IS EXCESSIVE FROM BOTH A "TOP-DOWN" PERSPECTIVE AND BASED ON SPECIFIC "BOTTOMS-UP" ADJUSTMENTS

A. O&M Expense is Excessive from a "Top-Down" Perspective

Q. Please describe the O&M expense included in the Company's proposed revenue requirement.

A. The Company proposes $354.531 million in O&M expense for the test year (on a jurisdictional basis), excluding amounts recovered outside of the base revenue requirement through the Fuel Adjustment Clause ("FAC"), Environmental Cost Recovery Clause ("ECRC"), and the Energy Conservation Cost Recovery Clause ("ECCR"). The Company's O&M expense request is summarized on Schedule C-2 and is detailed on various schedules included in its filing.

Q. How does the Company's test year request for O&M expense compare to 2012, the historical prior year?

A. The Company's test year request for O&M expense reflects significant proposed growth compared to the actual historical prior year 2012. The Company proposes an increase of $51.164 million on a total Company basis, or 16.3%, over the amount it actually incurred in 2012 ($364.126 million less $312.962 million). The Company provided its requested test year (2014), projected prior year (2013), and historical prior year (2012) O&M expense on a total Company basis, adjusted for proformas, and adjusted to exclude the O&M expense recovered through the various clauses on Schedule C-36 in its filing.

On a jurisdictional basis, the increase is even greater than on a total Company basis. The Company proposes an increase of $54.985 million, or 18.4%, in the test year compared to 2012. On a jurisdictional and adjusted proforma basis, the Company's projected test year O&M expense is $354.531 million compared to the actual $299.546 million incurred in 2012. The Company provided the adjusted proforma O&M expense information by year on a jurisdictional basis in Document 16, an attachment to Mr. Chronister's Direct Testimony.

Q. How does the Company's test year request for O&M expense compare to the pattern of actual O&M expense since 2009, the year of the Order in its last base revenue proceeding, through 2012?

A. Since the Order in early 2009, the Company (through its parent company, TECO Energy, Inc.) restructured its operations in the second half of 2009, successfully reduced its O&M expense in 2010 compared to 2009, and then managed and controlled its O&M expense so that it remained essentially flat through 2012. TECO Energy, Inc.'s 2009 SEC Form 10-K stated that mid-year it "announced organizational changes and a new senior executive team structure as part of its response to industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization." [TECO Energy, Inc. 2009 10-K at 164]. In his testimony in this proceeding, Company witness Mr. Brad Register describes the 2009 restructuring and the Company's "continuing desire to maintain a lean and efficient operation." [Register Direct Testimony at 7]. Mr. Register states:

> the Florida operations were streamlined and integrated to capture efficiencies and synergies throughout the entire organization. This integration led to a net reduction of 169 positions at Tampa Electric without adversely affecting service to our customers. All areas and levels of the organization were affected, excluding front line personnel.

[Register Direct Testimony at 7].

With respect to the Company's operating expenses, TECO Energy, Inc.'s 2010 10-K stated:

> [e]xcluding all FPSC-approved cost recovery clause-related expenses, the 2009 restructuring charges and the write-off of project development costs, operations and maintenance expense increased $5.1 million in 2010, due to the accrual of performance-based incentive compensation for all employees partially offset by lower spending on generating unit maintenance and other savings as a result of the 2009 restructuring actions. Tampa Electric expects operation and maintenance expense, excluding fuel and purchased power, to decrease in 2011, assuming normal levels of employee incentive compensation accruals.

[TECO Energy, Inc. 2010 10-K at 46-47].

TECO Energy, Inc.'s 2011 10-K stated:

> [e]xcluding all FPSC-approved cost recovery clause-related expenses, operations and maintenance expense decreased $23.6 million driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system. Tampa Electric expects operations and maintenance expense to increase in 2012 driven primarily by higher employee-related expenses, and higher costs to operate the transmission, distribution and power generating systems.

[TECO Energy, Inc. 2011 10-K at 48].

In its 2012 10-K, TECO Energy, Inc. stated that with respect to the Company's electric operation results:

> O&M expense, excluding all FPSC-approved cost-recovery clauses, increased $11.8 million reflecting higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense.

[TECO Energy, Inc. 2012 10-K at 40]. I have included these referenced excerpts from TECO Energy, Inc.'s 2009, 2010, 2011 and 2012 10-K filings as my Exhibit___(LK-21).

In summary, there actually was a net decrease in O&M expense over the 2010-2012 period compared to 2009, excluding the effects in 2009 of the restructuring charges and project development write-off costs. The Company's ability to achieve essentially flat O&M expenses since the last Order through 2012 stands in stark contrast to its request for an increase of $54.985 million, or 18.4%, from 2012 to the 2014 test year.

Q. Why is this history relevant to the Company's request in this proceeding?

A. It is relevant because the Commission must judge whether the Company's request is just and reasonable. The starting point for that judgment is to make a "top-down" assessment by comparing the total requested O&M expense in the test year to the total actual O&M expense incurred in prior years. This judgment is particularly important because the test year is projected and reflects the Company's wish list for O&M expense for a period that is two years beyond the most recent calendar year for which actual results are available.

The Company claims that its request reflects the return to a "normal" level of operations after several years of reduced and deferred activities. The question the Commission must answer is whether, and, if so, to what extent, this assertion is correct given the Company's self-interest in this proceeding to project significant increases in the test year. The best evidence in support of or against the necessity of such significant increases is the Company's own experience and statements over the last several years in response to the minimal sales growth and the "industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization" cited in its 2010 10-K.

The compelling actual evidence is that the Company can successfully manage and control its O&M expense if it has the real-world incentive to do so. The Commission found in the 2009 rate case that the Company's O&M expense request was excessive and reduced it by $23.977 million from the amount requested by the Company. Company witness Chronister states that in response to this reduction, the Company took "proactive steps to reduce O&M expense from budgeted amounts." [Chronister Direct Testimony at 31]. I have attached a copy of the Schedule included in the Commission's Order in the 2009 proceeding summarizing the Company's request and the Commission's adjustments as my Exhibit___(LK-2).

Q. How does the Company's request for an increase of 18.4% in jurisdictional O&M expense in the test year over the 2012 prior year actual compare to an increase that reflects only the Company's projection of inflation over the two year period, assuming no improvement in efficiencies and no changes in work-scope?

A. The increase in jurisdictional O&M expense over the two year period would be $14.087 million, a mere fraction of the jurisdictional $54.985 million increase proposed by the Company in this proceeding. I used the Company's projections of inflation to quantify this increase. The Company projects increases in inflation as measured by the CPI of 1.99% in 2013 and 2.66% in 2014, as shown on Schedule C-36 in its filing, an average of 2.3% annually, or 4.7% over the two year period. I computed the portion of the requested increase due to inflation alone by applying the Company's inflation rates as shown on Schedule C-36 to the $299.546 million (jurisdictional) actually incurred in 2012 as shown on Document 16 attached to Mr. Chronister's Direct Testimony. The application of these inflation rates to the 2012 jurisdictional amounts results in an inflation adjusted amount of $313.633 million (jurisdictional) for the test year.

Q. Is a jurisdictional O&M expense of $313.633 million just and reasonable considering the effects of inflation, improvements in efficiencies, additional investment in systems and other plant to achieve those efficiencies, and limited increases in work-scope activities, assuming that the Company continues its three year history of cost control as a "lean and efficient organization" and that the additional investments in systems and other plant

to achieve those efficiencies are included in rate base?

A. Yes. Consequently, I recommend a reduction in the Company's requested O&M expense of $40.898 million to $313.633 million on a jurisdictional basis. The Company has not justified an increase in O&M expense in the test year compared to 2012 of more than $14.087 million. The Commission should hold the line against unbridled projected O&M expense increases. This recommendation is consistent with the Mr. Homick's Direct Testimony wherein he states that:

> there has been a focus on controlling O&M expenses, particularly since 2009. Expense spending budgets have been held essentially flat, which has required the company to offset increases in labor, materials and other costs with reduced spending and efficiency measures across the company.

[Homick Direct Testimony at 11].

Q. **Have you compared the Company's proposed 2014 O&M expenses to the most recent year for which actual information is available on an account level basis to determine where the Company proposes to increase its O&M expense?**

A. Yes. The Commission must determine the just and reasonable level of O&M expense. Although I recommend that it do so through a "top-down" approach, I also provide a supplemental "bottoms-up" analysis of specific issues in further support of my recommendation to disallow a portion of the Company's requested increase. This approach was necessary due to the lack of testimony addressing the reasonableness of the increase beyond general descriptions of a "return" to "normal" spend rates, whatever that abstract description means and however the Company may define "normal." The Company should not be allowed to define "normal" as the level it spent prior to its response to the last Order in 2009. The pre-2009 levels no longer are relevant or applicable due to the systemic organizational and process changes implemented by the Company in 2009 and thereafter. A more relevant and correct definition of "normal" should be 2012 because it reflects the changes implemented in 2009 and thereafter. The 2012 prior historical year represents the most recent year for which actual amounts are available and the most recent year in which the Company had a direct self-interest in controlling and minimizing increases in its O&M expenses. The Company provided its actual O&M expenses and projected test year expenses by Federal Energy Regulatory Commission ("FERC") O&M expense account on Schedule C-6 in its filing.

HUA, the Florida Office of Public Counsel ("OPC"), and the Commission Staff ("Staff") served numerous interrogatories addressing the significant increases in many of these accounts in the test year compared to 2012. This comparison on an account by account basis was hindered in part by the fact that the Company reviewed its accounting in early 2012 in conjunction with the implementation of a new accounting system and changed the accounts it used for recording the costs of numerous activities as a result of that review. In many of the Company's responses to this discovery, this change in accounting was cited as a reason for the significant increases in certain accounts. However, there should have been a concomitant reduction in the other accounts if the changes in accounting were the sole driver; generally, there were no such reductions, with only a few exceptions.

The resulting difficulty in performing an account by account comparison to determine the reasonableness of the Company's proposed O&M expense spend rate leads to the necessity, and reinforces the reasonableness, of the "top-down" approach that I recommend the Commission employ in this proceeding. Nevertheless, I also have reviewed specific O&M expense areas and specific O&M expense accounts to assess the reasonableness of the Company's requested increases under a "bottoms-up" analysis. I address these specific issues and set forth specific adjustments in the following sections of my testimony based upon a "bottoms-up" approach that, in the aggregate, support my recommendation to set the allowed O&M expense using a "top-down" approach.

B. Energy Supply Maintenance Outage Expenses Should Be Normalized to Reflect Recent Actual Experience

Q. Please describe the Company's request to increase the Energy Supply O&M expenses in the test year compared to 2012.

A. The Company proposes to increase the Energy Supply O&M expense by $21.566 million (*i.e.*, from $117.274 million in 2012 to $138.840 million in 2014), as shown on the revised version of Mr. Hornick's Exhibit No. ___ (MJH-1) Document 4.

Q. What has been the Company's recent history of Energy Supply O&M expense?

A. Since the restructuring in 2009, the Company reduced its Energy Supply O&M expense and kept it essentially flat. The Company actually incurred $120.325 million in 2010, $115.366 million in 2011, and $117.274 million in 2012, according to the revised version of Mr. Hornick's Exhibit No. ___ (MJH-1) Document 4.

Q. How much of the proposed increase in the test year is for planned maintenance outage expense?

A. The Company seeks an increase of $6.830 million for planned maintenance outage expense, to $17.585 million in 2014 from $10.755 million in 2012, which is an increase of 64%. The Company provided the historical O&M expense by unit in response to OPC's Interrogatory No. 75 ("OPC-I-75") and the test year O&M expense by unit in response to OPC's Interrogatory No. 77 ("OPC-I-77"). The increase is primarily related to planned outages for the Big Bend units that exceed the average O&M expense for these units over the most recent 10 years, according to the Company's response to OPC-I-75. I have attached a copy of the response to OPC-I-75 as my Exhibit___(LK-3) and the response to OPC-I-77 as my Exhibit___(LK-4).

Q. Should the Commission normalize the planned maintenance outage expense so that it is consistent with historic amounts?

A. Yes. The Company's proposed expense is wildly in excess of the amounts that it incurred historically. Since 2009, the Company's planned maintenance outage expense has not exceeded $2.5 million on any one of its four Big Bend units. In stark contrast to its actual recent experience, the Company proposes planned maintenance outage expense of $5.4 million on Big Bend 1 and $5.7 million on Big Bend 4 in the test year. These stark differences and the magnitude of the increase in spending should weigh strongly in favor of normalizing the expense based on historic spending levels instead of blindly adopting the Company's proposed increase.

Q. What is the effect of normalizing planned maintenance outage expense?

A. The effect, under a "bottoms-up" approach, would be a reduction of \$7.145 million in planned outage expense based on the average of the three most recent years for which actual information is available. The average for the years 2010-2012 is \$10.440 million, based on the simple average of the actual annual expense amounts provided in the Company's response to OPC-I-75.

C. Distribution Operation and Maintenance Expense Increase is Excessive and Has Not Been Justified

Q. Please describe the increase in projected test year O&M expense compared to the actual O&M expense for the distribution operation and maintenance expense accounts.

A. The test year distribution operation expense is \$3.939 million, or 21.0%, more in the test year than the Company actually incurred in 2012, according to Schedule C-6. Schedule C-6 provides a comparison of prior year expenses compared to the Company's request in this proceeding by FERC O&M expense account. On Schedule C-6, the Company reflected \$22.715 million in the test year and \$18.776 million in 2012.

The test year distribution maintenance expense is \$3.443 million, or 13.7%, more in the test year than the Company actually incurred in 2012, also according to Schedule C-6. On Schedule C-6, the Company reflected $28.570 million in the test year and $25.127 million in 2012.

Q. Did the Company justify these significant increases through the testimony of its witnesses, or more specifically, through Ms. Young's testimony?

A. No. Consequently, HUA served a series of Interrogatories and Requests for Production of Documents ("PODs") addressing the specific accounts where the Company proposes significant increases. For example, the Company proposes $0.439 million for account 581 *load dispatching distribution* in the test year compared to the actual $0.059 incurred in 2012, an increase of 744.1%. The Company explained in response to HUA's Interrogatory No. 76 ("HUA-I-76") that $0.439 million of this increase was due to a shift in accounting in mid-2012 where expenses previously recorded in account 593 were shifted to account 581. However, when reviewing account 593, the expense in that account increased by $1.584 million in the test year compared to 2012. Thus, this explanation does not justify the increase in account 581 that is requested. I have attached a copy of the Company's response to HUA-I-76 as my Exhibit___(LK-5).

As another example, the Company proposes $5.533 million for account 583 *overhead line expenses distribution* in the test year compared to the actual $0.750 incurred in 2012, an increase of 637.7%. The Company explained in response to HUA's Interrogatory No. 61 ("HUA-I-61") that $4.579 million of this increase was due to shifts in accounting in mid-2012 where expenses previously recorded in accounts 580, 588, and 593 were shifted to account 583. However, there was no net reduction in these three accounts to offset the increase in account

583 due to these "accounting" changes. Instead, these three other accounts increased in the test year by a net $2.210 million (account 580 went down by $0.147 million; account 588 increased by $0.773 million; and account 593 increased by $1.584 million). I have attached a copy of the Company's response to HUA-I-61 as my Exhibit___(LK-6).

In short, the Company's explanation of "accounting" changes does not justify the increase in account 583 that was requested and does not explain the net increases in all four of the affected accounts.

Q. **Aside from the Company's description of accounting changes, do these responses otherwise justify the increases in distribution operation and maintenance expenses reflected in the Company's projected test year revenue requirement?**

A. No. They merely provide a narrative description of the increases the Company included in the test year, but do not justify those increases. These narrative descriptions are inherently circular, *i.e.*, the amount increased because it includes additional amounts. Further, the accounting changes obscure the details of the increases on an account by account basis, but when considered together with the other distribution accounts, do not justify the overall increases on an account by account basis.

Q. **What is the effect of your recommendation on distribution operation and maintenance expense under a "bottoms-up" approach based on these facts?**

A. The effect, under a "bottoms-up" approach, would be a reduction of $5.317

million of the Company's request by reducing the distribution O&M expense to the average inflation growth since 2012 projected by the Company and shown on Schedule C-36. This assumes that any increases due to program or work-scope expansion are funded through efficiency improvements. This is a reasonable result given the Company's failure to provide substantive and rational justifications for the proposed huge increases in these expenses.

Q. One of the drivers of the distribution O&M expense increases is the addition of 40 positions. Please address the addition of these positions.

A. The Company asserts that these positions are necessary based on "workload projections and apprentices required to replace future front line retirements" and to "respond to an aging infrastructure," according to its response to Staff's Interrogatory No. 48 ("Staff-I-48"). However, the Company provided no evidence that the work-scope will be any greater in the test year than it was in 2012 or that the so-called "aging infrastructure" requires more operation or maintenance expense than it did in 2012 or that the replacement of retiring workers will be any greater in 2014 than it was in 2012. I have attached a copy of the Company's response to Staff-I-48 as my Exhibit___(LK-7).

Q. Do you have any further comments on the Company proposed increase in distribution O&M expense in the test year compared 2012?

A. Yes. The Company has invested heavily in new infrastructure, which is included in the test year rate base through the end of 2014. The Company has implemented an extensive storm hardening program, including maintenance programs, vegetation management, distribution maintenance, pole replacements, and other initiatives and actions, according to the Storm Hardening Plan addressed by Ms. Young. [Young Direct Testimony at 26-27]. The Company provided a copy of the Storm Hardening Plan in response to OPC's POD No. 76. In addition, the Company now is on a cycle-based vegetation management program, which ostensibly is lower cost than a reliability-based program.

These investments and programs, which are paid for by customers, should result in continuing and growing savings through the test year. In fact, it is these very investments and programs that have enabled the Company actually to achieve savings in O&M expense in recent years. These investments and programs should operate to continue to restrain growth in the distribution O&M expenses in future years. Thus, the Commission should view the Company's request for significant increases in these expenses with extreme skepticism and instead allow only a reasonable increase consistent with my analysis. The Commission, and more importantly, the Company's customers, who have paid and continue to pay the costs of these investments and initiatives, should see the benefits of these investments and programs in the form of savings. The test year expense should reflect the savings in lower O&M expense from reduced work-scope, not increased O&M expense.

D. Incentive Compensation Expense Increase is Excessive and Has Not Been Justified

Q. Please describe the Company's requested increase in Performance Sharing Plan ("PSP") incentive compensation expense.

A. The Company proposes to increase the PSP incentive compensation expense by $5.956 million, from $6.427 million in 2012 to $12.383 million in 2014, according to the Company's response to OPC's Interrogatory No. 8 ("OPC-I-8"). The expense in 2012 was based on 2.0% of payroll, according to the Company's response to OPC's Interrogatory No. 60 ("OPC-I-60"), and the proposed expense in 2014 is based on 5.0% of payroll, according to Company witness Mr. Brad Register. [Register Direct Testimony at 18]. The Company has not yet determined the PSP goals for 2014, but they are expected to be "consistent" with the goals for 2013, according to Mr. Register. [*Id.* at 17]. The Company claims that there is another 7.0% available based on financial performance, but that it did not include this amount in its revenue requirement, also according to Mr. Register. [*Id.* at 18]. I have attached a copy of the Company's responses to OPC-I-8 and OPC-I-60 as my Exhibit___(LK-8) and Exhibit___(LK-9), respectively.

Q. Is the PSP incentive compensation expense discretionary and does the Company change the goals and percentages from year to year?

A. Yes. The Company reassesses the PSP incentive compensation expense goals and percentages each year. For example, in 2008, the potential payout was 4.0%, consisting of 2.25% for various safety and operational goals and 1.75% for financial goals. However, in 2012, the potential payout was only 2.0%, consisting only of safety goals due to the failure to achieve the Company's financial goals.

Q. Why is it relevant whether the PSP incentive compensation expense is discretionary?

A. It is relevant because the Company is under no obligation to continue the PSP or to set goals that benefit customers or challenge the organization to achieve metrics that directly benefit customers. In other words, even if the expense is allowed, the Company is under no obligation to pay these amounts. It may pay less or it may pay more, depending on the annual targets that it sets and its financial performance.

Q. What is the effect of your recommendation to reject the proposed increase in PSP incentive compensation expense under a "bottoms-up" approach?

A. The effect, under a "bottoms-up" approach, would be a reduction of $5.304 million to eliminate the Company's proposed increase. This reduction would allow recovery of no more than $7.079 million, using the 2.0% payout rate from 2012. This amount reflects the increase in payroll in the test year compared to 2012. To quantify the amount that should be allowed, I used the ratio of the $6.427 million in PSP incentive expense to the $194.408 million in payroll dollars in 2012 from the Company's response to OPC's Interrogatory No. 57 ("OPC-I-57") and applied this ratio to the $214.139 million in proposed payroll dollars in 2014, also from the Company's response to OPC-I-57. I have attached a copy of the Company's response to OPC-I-57 as my Exhibit___(LK-10).

Q. HUA witness Mr. Baudino notes in his testimony that the Company's common equity ratio is greater than the comparative group's. What is the significance of the common equity ratio on the revenue requirement?

A. Common equity is the most expensive source of financing for two reasons. First, the return on equity generally is much greater than the cost of debt. In this case, the Company seeks an 11.25% return on equity, a 5.40% cost of long-term debt, and a 1.47% cost of short-term debt. The weighted average cost of the long-term debt and short-term debt is 5.34%.

Second, the return on equity must be grossed-up for income taxes. The cost of debt is not grossed-up for income taxes. The gross-up factor for the return on equity is 1.6322. Thus, the return on equity sought by the Company is equivalent to a before tax cost of 18.36%.

Q. What is the effect of reducing the common equity ratio by 1.0% and increasing the long-term debt ratio by 1.0%?

A. The effect is a reduction in the revenue requirement of $5.6 million.

Q. Regardless of whether the Commission employs a "top-down" approach or a "bottoms-up" approach to the Company's requested O&M expense, should the Commission consider options to incentivize the Company to maximize actual PSP incentive compensation tied to a reduction in its common equity ratio and an increase in its long-term debt ratio?

A. Yes. I recommend that the Commission consider two options to incentivize the Company to reduce its common equity ratio. The first option would be to reduce the common equity ratio in the rate of return in this case and then allow the Company to retain 25% of the revenue requirement reduction as an increase to the PSP incentive compensation expense. In that manner, for each reduction of 1% in the common equity ratio, the Commission would reduce the revenue requirement by $5.6 million through a lower rate of return, but then increase it by $1.4 million through an increase to the PSP incentive compensation expense.

The second option would be for the Commission to establish an incentive for the Company to reduce its common equity ratio in the next rate case compared to the common equity ratio allowed in this case. The Commission could state its intent to allow a proforma adjustment to increase the PSP incentive compensation expense in the next rate case for 25% of the savings in the revenue requirement due to the lower return in the next case.

E. Stock Compensation Expense

Q. Please describe the Company's request for stock compensation expense.

A. The Company included stock compensation expense of $5.084 million in the revenue requirement for the test year, according to the Company's response to OPC-I-57. The Company incurred $2.703 million for this expense in 2010, $3.006 million in 2011, and $3.679 million in 2012, according to the response to OPC-I-57. Unlike its other benefit costs, the Company expensed the entire cost each year and did not capitalize any amount.

The Company's stock compensation expense is based on the grant and payout of performance shares and time-vested restricted stock pursuant to the Company's long-term incentive awards, according to TECO Energy, Inc.'s 2013 Proxy Statement. The payout of these awards is based on the Company's total shareholder return compared to the companies in the Dow Jones Conventional Electricity and Multiutility subsectors of its utility index, also according to the 2013 Proxy Statement. I have attached excerpts of the TECO Energy, Inc. 2013

Proxy Statement as my Exhibit___(LK-22).

Q. Should the Commission include stock compensation expense in the revenue requirement?

A. No. This expense is incurred to incentivize the financial performance of the Company, not to achieve operational or customer service goals that may directly benefit the customers. As such, the expense should be borne by the Company's shareholder, TECO Energy, Inc. In addition, the Commission should not provide financial incentives to seek and obtain rate increases and higher authorized returns on equity, particularly when such increases are paid by the same customers who are asked to pay for this incentive against their interests. Again, the expense should be borne by the Company's shareholder, TECO Energy, Inc.

F. Injuries and Damages Expense Should Be Normalized to Reflect Recent Actual Experience

Q. Please describe the Company's requested injuries and damages expense.

A. The Company proposes injuries and damages expense of $6.806 million according to its response to OPC's Interrogatory No. 12 ("OPC-I-12"). I have attached a copy of this response as my Exhibit___(LK-11). No witness explicitly addresses this expense in his or her Direct Testimony.

Q. How does the Company's request compare to its actual expense in prior years?

A. The Company's request is $1.728 million greater than the $5.078 million average of the injuries and damages expense actually incurred in the years 2010 through

2012. The Company incurred \$3.663 million in 2010, \$5.018 million in 2011, and \$6.552 million in 2012, according to its response to OPC-I-12.

Q. Under a "bottoms-up" approach, should the Commission consider the Company's historical experience and normalize this expense for the test year based on that experience?

A. Yes. Under the "bottoms-up" approach, the Commission should normalize this expense based on the Company's actual experience and reduce the amount included in the revenue requirement by \$1.728 million to reflect its most recent three years of experience. The Company uses reserve accounting and presently has a liability reserve balance, meaning that the Company has accrued and customers have contributed more to the reserve than the Company has paid out for such damages. Unlike the storm damage expense accrual, the Company does not accrue the same amount authorized by the Commission each year and retains discretion to accrue an amount each year based on experience and its determination of an appropriate reserve.

G. Miscellaneous General Expense Is Excessive because It Does Not Reflect TECO Energy, Inc.'s Acquisition of New Mexico Gas Company and the Lower Allocation of Affiliate Costs to the Company

Q. How does the Company account for affiliate charges from TECO Energy, Inc. in the test year?

A. The Company includes these amounts in account 930, Miscellaneous General Expense, although it recorded such charges in a variety of accounts in prior years.

Q. Did the Company reflect the lower affiliate charges from TECO Energy, Inc. that will result from TECO Energy, Inc.'s acquisition of New Mexico Gas Company?

A. No, according to the Company's response to OPC's Interrogatory No. 131 ("OPC-I-131"). The Company claims that it presently does not know whether TECO Energy, Inc. will direct charge any of its expenses to New Mexico Gas Company, according to its response to OPC's Interrogatory No. 133 ("OPC-I-133"), but it does agree that it will allocate a portion of the expenses that are not direct charged to the Company or other affiliates to New Mexico Gas Company starting in March 2014 when it closes on the acquisition, according to its responses to OPC-I-131 and OPC's Interrogatory No. 138 ("OPC-I-138"). I have attached a copy of the response to OPC-I-131 as my Exhibit___(LK-12), a copy of the response to OPC-I-133 as my Exhibit___(LK-13) and a copy of the response to OPC-I-138 as my Exhibit___(LK-14).

Q. Has the Company estimated what the reduction in allocated expenses will be?

A. Yes. The Company estimates that the reduction in allocated expenses will be $2.1 million in 2014, according to the Company's response to OPC-I-131, and $2.9 million in 2015 and 2016, according to its response to OPC-I-138. If some of the allocated expenses instead are direct charged to New Mexico Gas Company, then the reduction in the allocated charges to the Company will be greater than the Company quantified.

Q. Do you recommend that this reduction in af liate expense be reflected in the revenue requirement under a "bottoms-up" approach?

A. Yes. The effect, under a "bottoms-up" approach, would be a reduction in the Company's O&M expense of $2.9 million. The Commission should use the larger amount, rather than the $2.1 million amount estimated by the Company specifically for the test year. This is appropriate in order to reflect the annualized amount, rather than the savings for a portion of the year, and also to reflect the full impact of the acquisition on the Company, including the effect of a reduction in the allocated charges due to the fact that TECO Energy, Inc. likely will direct charge certain of its costs to New Mexico Gas Company, which should result in a reduction in the residual amounts that are allocated to the various affiliates using the modified Massachusetts methodology cited in the response to OPC-I-131.

H. Call Center Expense Increase Is Excessive and Has Not Been Justified

Q. Please describe the Company's requested increase in Call Center expenses.

A. The Company proposes to increase Call Center expense by $1.967 million in the test year compared to 2012, from $8.566 million to $10.533 million, according to its response to OPC's Interrogatory No. 49 ("OPC-I-49"). This is an increase of 23.0% over two years. The Company attributes part of this increase to additional staffing in order to improve Call Center metrics, according to its response to OPC-I-49. I have attached a copy of the response to OPC-I-49 as my Exhibit___(LK-15).

Q. Should the Commission authorize an increase of this magnitude in Call Center expenses?

A. No. First, the Company has provided no evidence that the 2012 performance was not acceptable. Second, the Company has provided no evidence that the 2012 performance was worse than its historical average. Third, the Company has provided no evidence that the 2012 performance was due to a lack of staffing. Fourth, the Company has provided no evidence why its other communication tools, including customer service interaction through its internet portal, either has been insufficient or cannot be improved in order to relieve any pressure on the Call Center.

Q. What is your recommendation with respect to the Call Center expenses under a "bottoms-up" approach?

A. I would recommend that the Commission reject an increase of this magnitude and instead increase the 2012 actual expense by the average inflation growth since 2012 projected by the Company and shown on Schedule C-36 to reflect inflation net of efficiency improvements and incremental expenses. This would result in an increase of $0.402 million, from $8.556 million to $8.958 million. I would recommend that the Commission reduce the Company's requested O&M expense by $1.575 million.

<u>I. Uncollectible Accounts Expense Increase Is Excessive and Has Not Been Justified</u>

Q. Please describe the Company's request for uncollectible accounts expense.

A. The Company proposes to increase the uncollectible accounts expense by $1.302 million in the test year compared to 2012. The Company implemented a new credit and collections system in 2011 along with other initiatives that reduced this expense compared to prior years, according to its response to HUA's Interrogatory No. 81 ("HUA-I-81"). However, the Company now believes that the uncollectible accounts expense "will trend toward the higher historical levels through 2014," according to its response to HUA-I-81. I have attached a copy of the response to HUA-I-81 as my Exhibit___(LK-16).

Q. Should the Commission approve this increase for recovery in the revenue requirement?

A. No. The Company has offered no empirical evidence that this expense will revert to historical levels. The Company's claim is particularly disturbing because of the investment in and implementation of technology in the form of the new credit and collections system along with the other "successful initiatives," such as the outbound dialer and better targeted and more aggressive collection policies, cited in the response to OPC-I-81. These costs also are included in the Company's revenue requirement. The savings from these initiatives also should be reflected.

J. Legal Expense Increase Is Excessive and Has Not Been Justified

Q. Please describe the Company's request for legal expense included in outside professional services in account 923.

A. The Company proposes to increase the legal expense by $2.254 million to $4.115

million in the test year, compared to $1.861 million 2012, as shown on the Company's corrected Schedule C-16 in its filing. The Company claims that the increase consists of $0.733 million for the amortization of rate case expenses, $0.520 million for pending litigation with Verizon, and $0.560 million associated with fuel contracts that are expiring, and other miscellaneous legal expenses, according to its response to OPC's Interrogatory No. 119 ("OPC-I-119"). I have attached a copy of the response to OPC-I-119 as my Exhibit___(LK-17).

Q. Should the Commission approve this increase for recovery in the revenue requirement?

A. No, except for the rate case amortization expense. The Commission should disallow the remaining $1.521 million. The Company has offered no evidence that it did not incur similar expenses in 2012, albeit for different contracts and other litigation. The Company does not propose a reduction in legal expenses for those similar expenses incurred in 2012 that will not recur in 2014. However, if, in fact, similar expenses were not incurred in 2012 and these expenses in the test year are nonrecurring, then the expenses should be deferred and recovery sought in the Company's next base rate case when they are known and measurable.

III. OTHER REVENUES SHOULD BE INCREASED TO REFLECT ONGOING OATT REVENUES FROM CALPINE

Q. In its filing, the Company assumed that it no longer would receive revenues or provide transmission service to Auburndale Power Partners ("APP") or Calpine under its OATT in the test year even though it had not received

official notice of termination from either of these entities. Has there been an update since the Company made its filing?

A. Yes. The Company recently received a notification from Calpine that it will roll-over 249 MW effective June 1, 2014 and ending May 31, 2019, according to its responses to HUA's Interrogatory No. 125 ("HUA-I-125") and Interrogatory No. 131 ("HUA-I-131"). This will result in an additional $4.92 million in revenues in the test year that were not reflected in the Company's revenue requirement, according to its response to HUA-I-131. I have attached a copy of the responses to HUA-I-125 and HUA-I-131 as my Exhibit___(LK-18) and Exhibit___(LK-19), respectively.

Q. **Should these additional revenues be reflected in the Company's revenue requirement?**

A. Yes. Consequently, the Company's revenue deficiency should be reduced by $4.92 million.

IV. RETURN ON EQUITY IS EXCESSIVE

Q. **If the Commission approves a reduction in the return on equity, as proposed by HUA witness Mr. Baudino, what effects will that have on the revenue requirement in this proceeding and in the various clause recoveries?**

A. In this proceeding, it will result in a reduction to the Company's claimed revenue deficiency and a reduction in the base revenue increase. It also will result in a reduction to the Company's clause revenue recoveries that include a return on rate base, such as the Environmental Cost Recovery Clause. The reductions in the clause revenue recoveries will partially offset any base revenue increase in this proceeding.

Q. Are there other effects resulting from a reduction in the return on equity?

A. Yes. A reduction in the return on equity also will reduce the rate of return used to capitalize financing costs during construction in the form of Allowance for Funds Used During Construction ("AFUDC"). The AFUDC is added to Construction Work in Progress ("CWIP") during construction and is included along with the direct costs of construction in Plant in Service when the CWIP is completed and placed in service. Due to the lower rate of return for AFUDC, the Company's rate base and depreciation expense will be less than if there had been an excessive return on equity during the construction period. Thus, a reduction in the AFUDC rate from the effective date of the Order in this proceeding until the next order in a subsequent proceeding resetting the return on equity will result in ongoing lower revenue requirements for decades over the service lives of the assets constructed during the period in which the lower AFUDC rate was in effect.

Q. Have you quantified the effect of the HUA return on equity recommendation in this proceeding?

A. Yes. The effect is to reduce the Company's revenue requirement by $58.375 million on a jurisdictional basis to reflect the reduction to the 9.3% return recommended by Mr. Baudino from the 11.25% return sought by the Company. The effect is to reduce the Company's revenue requirement by $29.936 million for each 1.0% change in the return on equity. I relied on the Company's rate base, capital structure, and cost of all capital components, except for the return on equity, to quantify the effects of modifying the return on equity; however, the effects will vary depending on the adjustments to rate base and capital structure that are adopted by the Commission in its Order. I provide my computations, including the reduction in the grossed-up rate of return, in my Exhibit___(LK-20).

Q. Does this complete your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF WILLIAM B. McNULTY

DOCKET NO. 130040-EI

JULY 25, 2013

Q. Please state your name and business address.

A. My name is William B. McNulty, and my business address is 2540 Shumard Oak Blvd., Tallahassee, Florida, 32399.

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

A. I am employed by the Florida Public Service Commission as an Economic Analyst in the Division of Economics.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since July 1989.

Q. Briefly review your educational and professional background.

A. I graduated from the University of Florida in 1981 with a Bachelor of Science degree in Psychology. I graduated from the University of Central Florida in 1989 with a Master of Business Administration degree. In that same year, I began employment with the Florida Public Service Commission as a Regulatory Analyst in the Division of Communications. Currently, I am employed as an Economic Analyst in the Division of Economics. During my tenure at the Commission, I have worked on a variety of issues involving all of the industries under the Commission's jurisdiction. In particular, I recently served as lead analyst in two rate cases, Docket No. 110138-EI (Gulf Power Company) and Docket No. 120015-EI (Florida Power and Light Company), on issues involving distribution cost classification proposals.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I have testified before this Commission In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor, Docket No. 030001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to provide an overview and analysis of the Demand Only Cost Classification (DOCC) distribution cost classification method that has been historically approved by the Commission and the Minimum Distribution System (MDS) distribution cost classification method proposed by Witness William R. Ashburn in this proceeding.

Q. Have you prepared exhibits to support your direct testimony?

A. Yes, I am sponsoring the following exhibits.

1. Exhibit No. ___ (WBM-1) Chapter 6 of the NARUC Electric Cost Allocation Manual – January 1992.

2. Exhibit No. ___ (WBM-2) Past Commission Orders Addressing the Minimum Distribution System (MDS).

3. Exhibit No. ____ (WBM-3) Higher Minimum Cost Using Minimum Size Methodology.

4 Exhibit No. ____(WBM-4) Zero Intercept Regression Statistics and Summary Output.

5. Exhibit No. ___ (WBM-5) TECO Test Year Revenue Requirement and Bill Impacts: MDS Compared to DOCC.

Q. What is Demand Only Cost Classification (DOCC)?

A. DOCC is the typical method that has been approved by this Commission to classify the distribution plant and related costs included in FERC Accounts 364 (poles, towers, and fixtures), 365 (overhead conductors and devices), 366 (underground conduit), 367 (underground conductors and devices), and 368 (line transformers) for purposes of cost allocation to the various customer classes. The standard classifications of electric utility costs are demand-related, customer-related, and energy-related. The purpose of any classification methodology is to reflect cost causation. If the cost to build and maintain certain plant is incurred to serve peak load, the cost is said to be demand-related. Peak load is metered voltage levels measured by utilities through load research studies. Historically, the utilities have classified all distribution costs associated with poles, conductors, line transformers and related equipment (Accounts 364 through 368) as demand-related, or DOCC.

If the cost of building and maintaining certain plant is incurred to serve a specific number of customers rather than to serve peak load, the cost is said to be customer-related. Historically, the Commission has classified all of the distribution plant and associated costs in Accounts 369 (service drops) and 370 (meters) as customer-related.

The method used to determine the classification of costs as demand-related or customer-related is important because it determines how costs are allocated to the various customer classes, which has a direct impact on the rates different customers pay for electric service.

Q. What is the Minimum Distribution System (MDS)?

A. The MDS is an alternative method for classifying distribution plant and related costs included in Accounts 364 through 368 (poles, conductors, line transformers, and related equipment). The MDS is based on the recognition that the number of distribution poles, conductors, and transformers varies with the number of customers on the system. The MDS classifies a portion of the costs for poles, conductors, and transformers as customer-related on that basis. It does so by defining the costs of a minimum sized system needed to serve a customer or a minimum "voltage pathway," a system which is sized so small that it is capable of serving only minimal or zero demand levels. Therefore, the portion of the costs that make up the "voltage pathway" are allocated to customer classes using the customer allocator (i.e. the number of customers in each rate class divided by total customers). The customer allocator typically results in a higher allocation of costs for the residential and small commercial classes than does the DOCC allocator. Thus, the use of MDS to classify some of the costs as customer related results in assigning more costs to the residential and small commercial classes and less costs to the large commercial and industrial classes.

Q. Is there a standard reference to develop the MDS cost classifications?

A. Yes. The primary reference literature for the MDS is the 1992 NARUC Electric Utility Cost Allocation Manual (the Manual). Chapter 6 of the NARUC Manual appearing in Exhibit No. ___ (WBM-1) addresses the classification and allocation of distribution plant. Chapter 6 explains how the MDS can be used to classify Accounts 364 through 368 plant using both demand and customer classifications. It describes the two methodologies for implementing MDS (the "minimum size" method and the "zero-intercept" method). The NARUC Manual also addresses the issues that may arise under each method, and in some instances it explains how the issues may be resolved.

Q. What is the "minimum size" methodology?

A. The minimum size methodology for classifying distribution plant is based on a theoretical minimum size system that could be built to serve the minimum load of the customer. As an example, according to the NARUC Manual, the customer component for poles (Account 364) is found by multiplying the minimum size pole's average book cost by the number of poles. The balance of the account is said to be the demand component.

Q. What is the "zero intercept" methodology?

A. The zero intercept methodology for classifying distribution plant is based on a theoretical no-load electric service to the customer. This method involves creating a graph or plot of the unit costs of distribution equipment of varying capacity sizes and estimating an upward sloping regression line which passes through the zero intercept, or vertical axis, normally at some positive value. The value at the zero intercept is supposed to be a statistical estimate of the customer component of the cost for a single unit of the equipment that has, theoretically, zero capacity. This unit cost is used to determine the customer component in the aggregate for the account or the voltage level. According to the NARUC Manual, separate customer components are established for primary and secondary voltages for Accounts 365, 366, and 367, depending upon the availability of subaccount cost data. For Accounts 364 and 368, a customer component is established for both voltage levels combined.

Q. Has this Commission required utilities to use the cost classification methods identified in the NARUC manual?

A. No. The NARUC manual is not mandated, but it is widely accepted as a primary reference for the assignment of costs.

Q. How has the Commission classified distribution costs since 1980, and what were its reasons for either approving or disapproving MDS?

A. The Commission has considered the MDS on 15 occasions since 1980 in the context of rate proceedings. The Commission has specifically rejected the MDS 12 times for investor-owned electric utilities (electric IOUs), approved the MDS under a settlement agreement for Gulf Power Company (Docket No. 110138-EI), and approved the MDS for Choctawhatchee Electric Cooperative (Docket No. 020537-EC). Most recently, the Commission approved the Florida Power and Light Company revised settlement based on DOCC. In each case wherein the Commission denied requests for the MDS cost classification, DOCC was the accepted method by which distribution costs were classified. A list of the Commission's past orders addressing the MDS appears in Exhibit No. __ (WBM-2).

Q. Has evidence been presented, either in this case or in recent dockets, which shows that the number of customers served is a causative factor for the installation of distribution poles, conductors, and transformers?

A: Yes. Utility distribution system planning documents have been presented in both the current proceeding and in the most recent FPL rate case (Docket No. 120015-EI) which clearly indicate that the number of customers to be served is a factor in the planning and construction of distribution assets, at least at the distribution secondary voltage level.[1]

Q. Is it possible to know precisely the proportion of distribution pole, transformer, and conductor costs that are customer related and demand related?

A. No. While the MDS attempts to quantify the costs of poles, conductors, and transformers which are caused by the number of customers served, the decisions made by utility distribution planners of how to build the system is best revealed by system planning documents. These documents typically are more general, perhaps containing a list of the factors to be considered when locating and sizing facilities, a chart showing the sizing of transformers according to the number of customers, or a discussion of the importance of taking into account the number of customers to be served by the asset or assets. These documents provide the best evidence that the number of customers are a partial cause of the costs, but they do not include a quantification or weighting of the reasons for installations or expansions between peak demand requirements and the number of customers served. On the other hand, post-hoc MDS calculations are designed to reveal the precise portion of the costs which are customer related. The task at hand requires distribution costs to be classified, a task which implies precision. The industry has responded with the MDS, but I believe it is

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[1] Transcript Volume No. 33, Page 4961, Docket No. 120015-EI.

important not to lose sight of the fact that, while MDS purports to be a precise methodology, it requires a knowledge as to the exact proportion of costs which are customer related and demand related which is simply not available.

Q. Does the NARUC manual identify any problems associated with the MDS the zero intercept methodology?

A. The NARUC manual identifies a problem of the zero intercept method wherein sometimes "abnormalities in the data" or "incorrect accounting data" can generate a negative value of the cost amount at the zero intercept (vertical axis). A negative value can not be interpreted and it is counter to common sense.

Q. Has TECO responded to the zero intercept methodology "data abnormalities" problem?

A. Yes. TECO has responded to the problem by relying upon replacement cost data rather than embedded cost data to conduct its zero intercept analysis of conductors and transformers. This is counter to the NARUC manual, which states that the appropriate data to use to determine the zero intercept cost is embedded cost data obtained directly from accounting records. TECO cites the analysis of Lawrence J. Vogt, P.E., in his book, <u>Electricity Pricing - Engineering Principles and Methodologies,</u> published in 2009. Mr. Vogt states that embedded cost data is often based on widely varying vintages of assets, which is the cause of the distorted zero intercept regression results and negative values of the zero intercept unit cost. To correct this problem, the author explains that the current replacement costs of all assets should be used in the regression model rather than embedded cost data in order to identify the zero intercept unit cost of the rebuilt system. A ratio of the zero intercept unit cost to total cost on a rebuilt basis is applied to total book costs to identify the customer related component of the assets in service.

Q. Does the NARUC manual identify any flaws or weaknesses in the minimum size methodology?

A. Yes. The minimum size methodology is relatively simple but is subject to the criticism that the use of the methodology may overstate the customer component of distribution costs because even the smallest conductor or transformer has some level of demand capability. Thus, demand costs at some level are still included in the customer component, meaning some level of demand costs are double-counted. The NARUC manual indicates that the zero intercept methodology may be a more accurate methodology than the minimum size methodology from a theoretical perspective because it reduces the demand capability of the asset to zero.

An illustration of this is contained in Exhibit No. ____ (WBM-3), "Higher Minimum Cost Using Minimum Size Methodology." Illustration A (Conductors) shows how TECO's zero intercept method applied to conductors generates a unit cost ($0.42/foot) which is lower than the cost of the smallest size conductor ($0.69/foot). TECO uses the zero intercept cost to develop their customer cost-related component.

Now consider Illustration B - "Poles," a hypothetical example showing how the zero intercept method applied to poles generates a zero intercept unit cost amount ($210/pole) which is lower than the cost of the smallest size pole ($300/pole), just as with the conductor example. However, in this instance the utility has chosen not to use the zero intercept method, instead choosing to simply use the cost of the minimum size pole as its unit cost for developing its customer component. The difference between the zero intercept cost and the smallest pole cost ($90) is counted as customer related cost, but it is actually demand related cost.

Q. Has TECO responded to the flaw with the minimum size methodology discussed

in the NARUC manual regarding the double counting of some level of demand costs?

A. No. TECO's costs associated with load carrying capability of the smallest pole is identified as customer related costs. TECO has not attempted any adjustments to extract the demand-related cost from the minimum size unit costs it has proposed. Allowing demand related costs of the minimum size unit to be counted as customer related costs is problematic in the same way as allowing all distribution costs of poles, transformers, and conductor to be counted as demand related costs (i.e. DOCC) when it is evident some costs are customer related.

Q. Is the zero intercept methodology a more accurate method for determining the customer component than the minimum size methodology?

A. It is likely, but not certain, because the zero intercept methodology as implemented has an additional problem beyond that identified in the NARUC manual. Utilities sometimes develop customer components with the zero intercept method using only a few observations in their regression models. This means the results of their model may have a very low level of statistical reliability.

For example, TECO performed its zero intercept analysis of primary conductors based on only three different size conductors, and the result of the regression is a positive zero intercept unit cost ($0.42), but the accuracy of that unit cost estimate is very low. This is evidenced by the 90 percent confidence interval for the zero intercept unit cost, which ranges from -$0.01 up to $0.86, as shown in Exhibit No. ___ (WBM-4), "Zero Intercept Regression Statistics and Summary Output." This means that there is a 90 percent chance that the true value of the zero intercept unit cost is contained within this range, but the range is very large, due to the fact that it is based on so few observations.[2] Zero intercept models with too few observations such as this are not very precise.

Q. What are TECO's proposed customer related components of its distribution costs in this proceeding using the MDS?

A. Using the MDS analysis, TECO proposes in this proceeding to classify 64 percent of its Account 364 costs (poles, towers, and fixtures), 24 percent of Account 368 costs (line transformers), and 9 percent of Accounts 365-367 costs (overhead and underground conductors and conduit) as customer-related. TECO proposes to classify the remaining costs in each of these accounts as demand-related.

Q. What are the revenue requirement impacts and expected bill impacts of the TECO's proposed implementation of the MDS on TECO's customers?

A. As shown in Exhibit No. ____ (WBM-5), the MDS as applied by TECO shifts revenue requirements of approximately $12.4 M to the residential (RS) class and $1.7 M to the small commercial (GS) class from primarily the general service demand (GSD) class and the lighting service (LS Energy and LS Facilities) classes. The total revenue requirement under the MDS is the same as the total revenue requirement under DOCC.

If TECO's rates were based solely on revenue requirements, the revenue requirement shift under the MDS as proposed by TECO would require TECO's RS customers to pay on average $1.67 per month more than they would under DOCC. The GS class customer would pay, on average, $2.14 per month more. The GSD class customer would pay, on average, $80.20 per month less under the MDS than under DOCC. The LS Energy class customer would pay, on average, $125.19 per month less under MDS than under DOCC, and the LS Facilities customer would pay, on average $115.98 per month less under the MDS than under

[2] The confidence interval is based on the assumption that the population of conductor sizes is normally distributed, wherein the population distribution forms a bell-shaped curve.

DOCC. See Exhibit No. ___ (WBM-5).

Q. What information should the Commission consider if it determines that an MDS methodology should be implemented in this case?

A. Primarily, I would recommend the Commission identify and evaluate each instance where TECO's implementation of the MDS differs from the methodologies recommended in the NARUC manual and whether such differences can be supported as reasonable and equitable. Implementing the MDS requires judgment in the development of the input cost data and this must be carefully reviewed in order to produce reliable results. Another area which should be reviewed is the cost treatment of ancillary costs within Accounts 364-368. Ancillary costs include the costs of such items as insulators, transformer platforms, regulators, and capacitors included in Accounts 364-368. Applying the MDS component ratio to all costs may not be advisable, since some of those assets are only demand-related and other assets are only customer-related.

Q. Beyond the technical issues pertaining to measuring cost causation, what are some of the regulatory impacts associated with the adoption of an MDS methodology?

A. The MDS provides two methods for recognizing the customer related costs in Accounts 364 through 368 which are missed by DOCC, albeit with the technical cost measurement issues noted above. Beyond those considerations, some of the consequences of the selection of cost classification methodologies involve ratemaking impacts. Rates based on DOCC feature lower customer charges and higher energy and demand charges than rates based on the MDS. Rates based on DOCC therefore provides clearer price signals for encouraging conservation than do rates based on the MDS methodology. For the same reason, rates based on DOCC also provide a customer with more control over his/her electric bill, which benefits the customer. Likewise, rates based on DOCC may reduce the incentive for seasonal customers to disconnect and reconnect service since fixed customer charges are lower under DOCC than the MDS.

On the other hand, rates based on the MDS may provide greater revenue stability to utilities. Under the MDS, rates may provide utilities a more certain and steady revenue stream as a result of higher customer charges and lower demand and energy charges, thereby reducing the utility's financial risk.

Q. Would you please summarize your testimony?

A. Yes. The classification of distribution costs in Accounts 364 through 368 (poles, conductors, and transformers) present a challenge and a dilemma for the Commission to resolve. The Commission's traditional method of cost classification, DOCC, misclassifies certain customer related costs, but the extent of misclassification is uncertain. Meanwhile, the MDS methodologies recognize customer related costs but the methodologies present significant cost measurement issues impacting the customer-related and demand-related components. Confidence in the methodology and the underlying data inputs is essential so that the Commission can reach an optimal decision regarding the appropriate treatment of distribution costs in this case.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF JEFFERY A. SMALL

DOCKET NO. 130040-EI

JULY 25, 2013

Q. Please state your name and business address.

A. My name is Jeffery A. Small and my business address is 4950 West Kennedy Blvd, Suite 310, Tampa, Florida, 33609.

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

A. I am employed by the Florida Public Service Commission as a Professional Accountant Specialist in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission (FPSC) since January 1994.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Science degree in Accounting from the University of South Florida. I am also a Certified Public Accountant licensed in the State of Florida.

Q. Please describe your current responsibilities.

A. Currently, I am a Professional Accountant Specialist with the responsibilities of planning and directing the most complex investigative audits. Some of my past audits include cross-subsidization issues, anti-competitive behavior, and predatory pricing. I am also responsible for creating audit work programs to meet a specific audit purpose and integrating EDP applications into these programs.

Q. Have you presented expert testimony before this Commission or any other regulatory agency?

A. Yes. I have provided testimony in the Progress Energy Florida, Inc. (PEF) Nuclear Cost Recovery Clause Filings, Docket Nos. 080009-EI, 090009-EI, 100009-EI, 110009-EI, 120009-EI and 130009-EI.

I have also testified in the Southern States Utilities, Inc. rate case, Docket No. 950495-WS, the transfer application of Cypress Lakes Utilities, Inc., Docket No. 971220-WS, and the Utilities, Inc. of Florida rate case, Docket No. 020071-WS.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff Auditors' Report of Tampa Electric Company (TEC) which addresses the Utility's application for rate relief in Docket No. 130040-EI, for the historical year end 2012. This Auditor's Report is filed with my testimony and is identified as Exhibit JAS-1.

Q. Was the audit prepared by you or under your direction?

A. Yes, the audit was prepared by me and under my direction.

Q. Please describe the work you performed in the audit.

A. The following procedures were performed.

- We verified, based on a sample of Plant in Service (PIS) additions, retirements and adjustments for selected plant accounts, that the Utility's PIS is properly recorded for the period January 1, 2008 through December 31, 2012. We recalculated a sample of 13-month average balances for PIS included in the filing.
- We verified, based on a sample of Property Held for Future Use (PHFU) properties presented in the filing, that the PHFU balance is properly stated as of December 31, 2012. We reviewed documents describing the planned use for properties in our sample and inquired about changes in use for existing properties. We recalculated a sample of 13-month average balances for PHFU included in the filing.
- We verified, based on a sample of Construction Work in Progress (CWIP) projects

included in the filing, that the CWIP balance is properly stated as of December 31, 2012. We reviewed utility documents describing each project sampled to determine whether it was eligible to accrue Allowance for Funds Used During Construction (AFUDC). We verified that projects accruing AFUDC were not included in rate base in the filing. We recalculated a sample of 13-month average balances for CWIP included in the filing.

- The objectives were to determine whether accruals, retirements and adjustments to Accumulated Depreciation (AD) are properly recorded in compliance with the Uniform System of Accounts (USOA), and to verify that the Utility used the depreciation rates established in Commission Order No. PSC-12-0175-PAA-EI – Petition for Approval of 2011 Depreciation Study and Annual Dismantlement Accrual Amounts by Tampa Electric Company, issued April 3, 2012, and, to recalculate the 13-month average balance for AD as of December 31, 2012.
- We verified, based on a sample of selected accounts, that the Working Capital (WC) balance is properly stated, utility in nature, non-interest bearing, does not include non-utility items and is consistent with the order cited above. We verified, based on a sample of selected accounts that the accumulated provision accounts year end balances comply with the Commission rule cited above. We recalculated a sample of 13-month average balances for selected WC accounts included in the filing.
- We traced the equity account balances to the general ledger. We verified retained earnings by reconciling a sample of dividend distributions to the dividend declarations of the TECO Energy, Inc. Board of Directors. We recalculated the 13-month average balance for equity included in the filing.
- We reconciled the Long Term Debt (LTD) balance to the general ledger. We traced the LTD obligations and the unamortized loss on reacquired debt balance to the

original documents and verified the terms, conditions, redemption provisions and interest rates for each bond or note payable. We sampled and verified the cost of LTD. We recalculated the average cost rate and the 13-month average balance for LTD included in the filing.

- We reconciled the Short Term Debt (STD) balance to the general ledger. We traced the STD obligations to the supporting documents. We verified the average cost of STD. We recalculated the average cost rate and the 13-month average balance for STD included in the filing.
- We reconciled the Customer Deposit (CD) balance to the general ledger. We inquired and verified that the Utility is collecting, refunding and paying interest on CD based on Commission Rule 25-6.097, Florida Administrative Code (FAC) – Customer Deposits.. We recalculated the average cost rate and the 13-month average balance for CD included in the filing.
- We reconciled the Accumulated Deferred Income Tax balances to the general ledger and to the federal tax returns. We recalculated the 13-month average balance included in the filing.
- We reconciled the Investments Tax Credit balances to the general ledger. We recalculated the average cost rate and the 13-month average balance for ITC included in the filing.
- We reconciled 2012 revenues to the general ledger. We reviewed Commission audits of the Utility's cost recovery clauses, which included recalculations of a sample of customer bills, to ensure that the Utility was using the rates authorized in its approved tariff. We verified that unbilled revenues were calculated correctly.
- We verified, based on a sample of utility transactions for select Operation & Maintenance (O&M) expense accounts, that 2012 O&M expense balances are

adequately supported by source documentation, utility in nature and do not include non-utility items and are recorded consistent with the USOA. We reviewed samples of utility advertising expenses, legal fees, outside service expenses, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed. We reviewed a sample of intercompany allocations and charges to determine if expenses were allocated pursuant to Commission Rule 25-6.1351 – Cost Allocation and Affiliate Transactions, F.A.C.

- We recalculated a sample of depreciation expense accruals to verify that the Utility is using the correct depreciation rates cited above.
- We verified, based on a sample of transactions for select Taxes Other Than Income (TOTI) accounts, that TOTI expenses are adequately supported by source documentation.
- We traced federal and state income taxes to the general ledger. We documented bonus depreciation treatment for asset additions. We verified that adjustments to income tax expense are consistent with the USOA and calculated correctly.
- We developed a five-year (2008 -2012) analytical review that compared the annual percentage change and the 2012 over 2007 total percentage change for the Federal Energy Regulatory Commission (FERC) account balances. Accounts that exhibited significant activity or percentage change, as determined by the auditor, were randomly selected for additional review.
- We reviewed the 2007 and 2008 FERC audit reports for TEC, that were issued on August 21, 2007 and August 18, 2008, respectively. We reviewed the 2012 annual report and associated audit work papers for TECO and its subsidiaries, including TEC. The annual report was released on February 26, 2013, and included the unqualified

opinion by PricewaterhouseCoopers (PWC) of TECO consolidated operations.

- We reviewed the respective Board of Directors meeting minutes for TEC and TECO through March 15, 2013, for activities or issues that could affect TEC in the current rate case proceeding.

Q. Were there any audit findings in the audit report, JAS-1, which address the historical 2012 balance in the Utility's filing.

A. No

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
FILED: 08/08/2013

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

KAREN J. LEWIS

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

A. My name is Karen J. Lewis. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Customer Services.

Q. Please describe your educational background and business experience.

A. In 1984, I received a Bachelor's of Science in Industrial Engineering from Auburn University. Upon graduation I joined Gulf Power Company, where I worked for two years before joining Progress Energy and working there from 1987 to 2001. In 2001, I joined Tampa Electric as a Director in Energy Delivery where I worked in various management roles until 2009. In 2009, I became Director Customer Services for Tampa Electric and Peoples Gas, which is my current position.

Q. What are your responsibilities as the Director of Customer Services?

A. I have responsibility for the following Customer Service functions for both Tampa Electric and Peoples Gas. The functions include, but are not limited to the call center front line operations, call center support functions (training, workforce scheduling, workforce performance metrics), billing, payments, credit and collections and escalated customer complaints.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimony of witnesses Helmuth W. Shultz, III, and Donna Ramas, testifying on behalf of the Office of Public Counsel ("OPC") and Lane Kollen testifying on behalf of the West Central Hospital Utility Alliance ("HUA").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes, I have. My Exhibit No.__ (KJL-1), consisting of four documents, was prepared by me or under my direction and supervision.

Document No. 1	JD Power & Associates Survey Results 2010-2013
Document No. 2	Call Center Staffing and Service Levels 2009-2013
Document No. 3	Write Off Trends 2008-2012
Document No. 4	Florida Public Service Commission ("FPSC") Complaint Trends 2008-2013

Q. Please summarize the key concerns and disagreements you have regarding the substance of witnesses Shultz's, Ramas's and Kollen's testimonies.

A. My key concerns and disagreements are as follows:

1. I disagree with witness Shultz's assertion that an adjustment to remove 104 of the 114 positions in the company's test year is appropriate. Of those 114 positions, 16 are customer service related positions that are essential to maintain appropriate service levels and minimize uncollectible revenues. The Commission should not make an adjustment to reduce operations and maintenance ("O&M") expense for these 16 positions.
2. I disagree with witness Ramas's and witness Kollen's

position that a reduction to uncollectible expense is appropriate. I will explain how the company's efforts to reduce bad debt have benefited customers and why the expense level requested by the company is reasonable, prudent and necessary.

3. I disagree with witness Kollen's position that a reduction of call center expense is appropriate. I will explain the drivers for incremental call center expense and why those expenses are appropriate, reasonable and prudent to maintain adequate customer service levels.

APPROPRIATE HEADCOUNT LEVELS

Q. Are additional call center positions necessary to maintain and improve service levels?

A. Yes. Of the proposed headcount reductions in witness Shultz's testimony, 16 of the 104 are in Customer Service. Of those 16 positions, 12 are in the call center, three are in Billing & Payments and one is an Administrative Assistant.

Call center Representative staffing in 2012 was well below historical levels. In 2012, call center staffing was reduced in an effort to control costs by cancelling new hire classes and not addressing normal attrition with new hires. Staffing reductions had a negative effect on customer service levels, which is reflected in the company's JD Power & Associates survey results shown in Document No. 1 of my exhibit. In order to address the decline in customer service levels, in 2013, 12 additional call center Representatives were hired. As a result, call center response times and customer satisfaction have improved.

Q. What positions have been filled or are being budgeted to be filled in 2014?

A. As of the date of the filing of this rebuttal testimony, the company has filled 16 of the 16 customer service positions that witness Schultz has proposed to adjust. Of the 16 who have been hired, 14 are front line customer service agents who spend the vast majority of their time dealing directly with customers. The other two positions provide administrative support for Customer Service.

A Senior Administrative Specialist was hired to provide support to the Director and three Managers, and that position is the only administrative support for that group. An Administrative Specialist vacancy in Billing &

Payments was filled because the incumbent was promoted to another position within the company. This vacancy was filled in 2013, and that position is the sole administrative support for 32 team members. Finally, two Billing Payment Specialists were hired in 2012 to help handle the increasing workload within the department.

Q. What functions do call center Representatives perform that impact customer satisfaction?

A. The company has two call center locations, one in Tampa and one in Plant City. Together, the two call centers employ 108 call center representatives. Customers can reach the call centers through a local or toll free number. Calls are passed through an Integrated Voice Response ("IVR") system to enable self-service options. Approximately 50 percent of the inbound customer calls are serviced within the IVR. The remaining 50 percent of our customers that elect to speak with a representative are routed to the first available agent. As one would expect, lower staffing levels result in longer wait times for customers that need to speak with a representative.

Q. What metrics does the company monitor to assess the level of customer service provided by the call centers?

A. The time it takes for a customer to speak with a representative is represented in the Customer Service Professional ("CSP") Service Level metric and the Average Speed of Answer ("ASA") metric shown in Document No. 2 of my exhibit. The company strives to answer at least 65 percent of these calls within 30 seconds. In 2011, there were 109 agents handling customer calls, and the CSP Service Level was 70 percent. In 2012, there were 98 agents handling residential calls, and the CSP Service Level dropped to 53 percent. The service level metric shows the direct correlation between call center service levels and customer satisfaction. The decline in call center response time and the desire to continue improving response times is why the company increased the number of team members employed at the call centers.

Q. Do you believe the company will be able to maintain its level of customer service in the call center if the Commission accepts witness Schultz's proposed elimination of 16 call center positions?

A. No, I do not. The company needs the additional positions to improve customer service and cannot reduce those positions without jeopardizing service levels.

CALL CENTER EXPENSES

Q. Do you agree with witness Kollen's statement that test year call center expenses have not been justified?

A. No. As previously stated, the company has already added 12 call center agents in 2013, resulting in an incremental annual labor cost of $550,000. Call center staffing was reduced in 2012 as a means to reduce costs. As a result, customer service levels and customer satisfaction declined. The 12 positions added in 2013 restored staffing to previous levels. Document Nos. 1 and 2 of my exhibit illustrate the correlation between resources, customer satisfaction and customer service levels.

Q. How is the call center performance tracked?

A. The call center uses qualitative and quantitative measures to evaluate performance. The company strives for a high level of customer satisfaction, and the call center places a great deal of focus on meeting the individual needs of each customer in an efficient, effective and pleasant manner. The qualitative measures include monitoring 100 percent of the calls and supervisor monitoring of a sufficient number of calls to ensure that CSP agents are meeting expectations. A Quality Assurance team also takes samples of calls from all representatives and evaluates the agents' performances. Other quantitative measures include the ASA and the CSP Agent's Service Level.

Q. What does the company consider to be acceptable call center performance and how has the company performed over the past several years?

A. The company strives to answer 65 percent of customer calls within 30 seconds. The company also focuses on other metrics such as ASA and the percent of calls that are abandoned (customer hangs up due to extended wait time). Historical 2009 through 2013 call center performance is illustrated in Document No. 2 of my exhibit. In late 2012, the call center dedicated a great deal of time and resources toward implementing an initiative known internally as "WOW". An outside consultant was brought in that had worked with numerous call centers for electric utilities. The consultant spent six months working with call center management. The WOW initiative focused on front line supervisors first and involved a great deal of training for the supervisors. Once management training was complete, the

CSP Agents were trained and they are continuously evaluated on WOW principles. This program has been very effective and has contributed to the increase in customer satisfaction in 2013.

Q. How does the company measure customer satisfaction?

A. Customer satisfaction is measured in various ways. The company started an after call survey in 2013 to solicit direct feedback from customers. Approximately 1,400 customers per month are surveyed and about 19 percent complete the survey. Year to date, an 82 percent favorability level has been achieved in survey responses. Similarly, JD Power & Associates surveys approximately 250 customers each quarter. JD Power & Associates survey results (specific to the call center) declined when the number of CSP agents decreased in 2012. After hiring 12 call center agents earlier this year, JD Power & Associates' scores have improved. The company also looks at customer complaint activity to gauge customer satisfaction. FPSC complaints have decreased over the past several years as reflected in Document No. 4 of my exhibit.

Q. Do you agree with witness Kollen's testimony that the

$1.9 million dollar increase in expenses from 2012 to 2014 is not justified?

A. No. The increase in call center expenses from 2012 to 2014 is due primarily to increased labor and vendor maintenance costs. The call center budget increased $861,000 from 2012 to 2013 due to the aforementioned 12 additional CSP agents, merit increases for all call center employees, costs associated with agent attrition, maintenance and licensing fees associated with the new Contact Center Manager ("CCM") application. In a typical year, the call center loses up to 25 percent of CSP agents due to promotion, resignation or termination. To mitigate this attrition, two or three new hire classes are needed each year. When CSP agents are hired, staffing levels increase above our targeted average. The temporary increase is intentional as new hires are in training for nine weeks post-hire and therefore not fully productive; and attrition will gradually lower headcount over the upcoming months to the targeted average headcount.

Q. What is the CCM application and how will it improve customer service?

A. The CCM application will be implemented in late 2013 and consists of an improved, customer-centric IVR and advanced workforce optimization tools. The existing IVR is challenging for customers to navigate, and the company is responding to customer concerns by implementing a new and improved IVR application. The CCM also includes Call Back Request. If a Call Center agent is not able to pick up the customer's call immediately, the customer can elect a call back instead of being placed on hold. The CCM will also enable advanced workforce scheduling and reporting tools for individual agents, thus increasing the productivity and efficiency of the call center. This CCM application requires annual maintenance and licensing fees of approximately $200,000.

Q. Do you agree with witness Kollen's testimony that the company failed to explain why other communication tools (including customer service interaction portal) has not relieved pressure on the call center?

A. The company does not understand witness Kollen's definition of "customer service interaction portal". But I will describe the mechanisms in place for customers to interact with CSP agents. Customers can reach the call center via local and toll free phone numbers. The previously mentioned CCM application will enhance the customer's phone interactions with the company.

The company also implemented Power Updates in June 2013. This service enables two way communications between the company and customers on power outages. Previously, customers called the company's outage reporting phone number to report an outage. Power Updates enables customers to use various modes of technology (mobile phone, tablet, and email or land-line phone) to report outages and to receive updates from the company on restoration status. The main benefit of the Power Updates application is that it enables customers to communicate with the company by means other than a phone call. This provides customer convenience and a positive influence on customer satisfaction. While it is certainly a beneficial customer resource, the application does not influence labor resource needs.

UNCOLLECTIBLE EXPENSE LEVELS

Q. Do you agree with witness Ramas's testimony that Tampa Electric's test year budgeted uncollectible expense is excessive?

A. No. The test year budgeted uncollectible expense is reasonable.

Q. What are your responsibilities in the areas of bad debt collection and bad debt expense?

A. I am responsible for the development and implementation of strategies related to managing and minimizing the company's uncollectible expense. This includes ensuring customers' accounts are properly secured with deposits. It also includes the management of collections on bad debt, prevention of bad debt and policies that target the identification of lost revenue as well as fraud prevention.

Q. What is bad debt expense?

A. Bad debt expense is the uncollectible revenues which can result from overdue/late payment of bills or customers vacating a premise with outstanding balances.

Q. Witness Ramas proposes that the test year uncollectible expense be based on the actual 2012 ratio of net write-offs to revenues. Do you believe that is appropriate?

A. No. Using the 2012 ratio of net write-offs to revenues does not take into account unique circumstances in 2012 that resulted in a significant reduction in uncollectible expenses. The 2014 test year uncollectible expense represents our expected future uncollectible expense and includes the impact of the new Credit and Collections System and other ongoing initiatives to reduce write offs.

Q. How does the company's proposed level of uncollectible expense in the test year compare to industry averages and the company's historical experience?

A. The test year net write-offs to revenues is 0.19 percent which is significantly lower than the industry average of 0.44 percent[1]. The 2014 test year net write-offs to revenues is also lower than the company's five year average of 0.28 percent. Write-offs fluctuate from year to year and are often influenced by economic conditions. The write-offs for 2012 were unusually low.

Q. What unique circumstances occurred in 2012 that affected the uncollectible expenses?

A. The company implemented a new collections system called DebtNext. DebtNext replaced a system that was 20 years old and reduces or eliminates manual work associated with

[1] Chartwell Facilitating Knowledge Exchange; Report on Credit and Collections in the Utility Industry 2010 © Chartwell Inc. 2010

the credit and collections process. This system is a vast improvement in how the company manages debt and has enabled the company to successfully collect on numerous accounts that had previously not tracked with the old system.

Q. Please describe the new systems and how they have helped reduce the level of uncollectible expense.

A. DebtNext searches outstanding account balances for uncollected debt and attempts to match these accounts with active accounts by name or social security number. When a match is determined and the transfer balance process begins, the system will generate letters advising the customer than an unpaid balance has been located and transferred to their account. If, after 60 days the payment has not been received, DebtNext automatically sends the account to the collection agency for recovery.

Q. What sustainable initiatives have been implemented that will keep uncollectible expense lower than pre-2011 levels?

A. The company developed many initiatives over the past several years to minimize uncollectible expense. The new

Credit and Collections System, DebtNext, has been discussed, and there are two other major initiatives that have impacted uncollectible expense. The company sharpened its procedures to ensure that it can positively identify customers applying for service. The company uses an outside vendor (Equifax) to validate the identification of new customers by confirming credit information, e.g., social security numbers or driver's license information to confirm the identity of the person applying for service. These procedures were implemented in 2010 and have had a positive effect on write-offs and fraud. Over the last several years, there has also been a focus on customer deposits, including an extensive review of all residential, commercial and industrial accounts to ensure all customer accounts were adequately secured.

Q. Have these new systems and initiatives shown positive results?

A. Yes. Document No. 3 of my exhibit illustrates the revenues and net write-off trends from 2008 through 2012. The average net write-offs from 2008 through 2012 was $5.7 million or 0.28 percent of revenue. After DebtNext was implemented in April 2011, the company experienced the peak benefit of the new system as net write-offs dropped to $2.3 million or 0.122 percent of revenue. DebtNext has now completed the full review of all existing debt and has exhausted any further matches with active customers for collection. Therefore, the low level of 2012 write-offs was a unique situation that is not sustainable. While the company expects that the DebtNext system will prevent write-offs from climbing back to the pre-2011 levels, the 2012 write-off level was a result of the system working through the company's existing customer base and capturing uncollectible expenses that were not detected in the past.

The 2014 test year uncollectible expense of $3.6 million is a reasonable estimate of the annual expected uncollectible expense. The company will continue to make all efforts to hold write-offs at or below this level going forward. However, the 2014 proposed test year uncollectible expense of $3.6 million is considerably lower than the 2008 through 2012 average of $5.7 million and should be approved.

Summary of Rebuttal Testimony

Q. Please summarize your rebuttal testimony.

A. The company has justified that its requested level of call center expense for 2014 is appropriate. Staffing levels declined considerably from 2011 to 2012, resulting in lower service levels and decreased customer satisfaction. The increase in customer service expense between 2012 and 2014 expense is primarily due to reaching and maintaining appropriate staffing levels, merit increases, and increased maintenance/license expense associated with a new CCM program.

The company has also justified its requested level of uncollectible expense for the 2014 test year as reasonable. The five-year average for write-offs is $5.7 million or 0.28 percent of revenue. The test year budget of $3.6 million or 0.19 percent of revenues is well below the five-year average. The company has implemented various programs, policies and procedures to lower write-offs; however, the 2012 levels should not be considered a baseline year because the implementation of a new collections system distorted that year's write-offs as a percentage of revenue statistics.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

DOCKET NO. 130040-EI
FILED: 08/08/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

TERRY DEASON

ON BEHALF OF TAMPA ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Terry Deason. My business address is 301 S. Bronough Street, Suite 200, Tallahassee, Florida 32301.

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

A. I am employed by the Radey Law Firm as a Special Consultant specializing in the fields of energy, telecommunications, water and wastewater, and public utilities generally.

Q. Please describe your educational background and professional experience.

A. I have thirty-six years of experience in the field of public utility regulation spanning a wide range of responsibilities and roles. I served a total of seven years as a consumer advocate in the Florida Office of

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

Degree in Accounting, summa cum laude, and a Master of Accounting, both from Florida State University.

Q. Have you prepared an exhibit supporting your Rebuttal Testimony?

A. Yes, I have. My Exhibit No.___ (TD-1), consisting of three documents, was prepared by me or under my direction and supervision. These consist of:

Document No. 1: Biographical Information for Terry Deason

Document No. 2: Consulting Services and Expert Testimony Provided by Terry Deason

Document No. 3: Amortization of a $10 Million Hypothetical Investment

Q. For whom are you appearing as a rebuttal witness?

A. I am appearing as a rebuttal witness for Tampa Electric Company ("Tampa Electric" or "the company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain assertions and recommendations made by intervenor witnesses Chriss, Gorman, Kollen, Pous, and Schultz. The issues I address in rebuttal to these witnesses are: Projected Test Year; Construction Work In Progress; Reconciliation of Rate Base and Capital Structure; Operations & Maintenance Expenses; Equity Ratio; Amortization of Software; Incentive Compensation; and, Directors and Officers Liability Insurance.

PROJECTED TEST YEAR

Q. What is the test year being used in this proceeding?

A. A 2014 projected test year.

Q. What does witness Chriss say about the use of a projected test year?

A. Witness Chriss states that a projected test year reduces regulatory lag and suggests that its use should result in a lower return on equity ("ROE") for Tampa Electric. He goes on to quote from Order No. PSC-02-0787-FOF-EI.

Q. Do you agree with Witness Chriss?

A. I agree that the use of a projected test helps mitigate regulatory lag. I disagree with his suggestion that the use of a projected test year should result in a lower ROE. Projected tests years are the established practice in Florida and have their origin as far back as 1983, when the Florida Supreme Court addressed the use of projected test years. In 443 So.2d 92, the Court stated:

> Nothing in the decisions of this Court or any legislative act prohibits the use of a projected test year by the Commission in setting a utility's rates. We agree with the Commission that it may allow the use of a projected test year as an accounting mechanism to minimize regulatory lag. The projected test period established by the Commission is a ratemaking tool which allows the Commission to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility.

Given that projected test years are the established practice in Florida, their continued use is a reasonable expectation of investors and is already reflected in the market metrics used to estimate a regulated utility's cost of equity capital. Only if the Commission were to revert to the use of historical test years would there be an impact on the capital markets. In that event, the cost of equity capital would likely be higher, not lower.

Q. Are you familiar with the Order cited by witness Chriss?

A. Yes, I am. This Order granted a rate increase to Gulf Power Company("Gulf") in 2002. The use of a projected test year was questioned by OPC, which sponsored the testimony of Helmuth W. Schultz III. Witness Schultz found fault with the projected test year and offered support for an adjusted historical year. The order stated:

> Witness Schultz testified that he made a number of adjustments based upon a historical level of spending that he considered sufficient to provide the quality of service. In his opinion, the historical spending should be used when establishing rates, especially when considering the lack of detail in the company's budget.

Q. What did the Commission decide?

A. While noting that historical and projected test years each have strengths and weaknesses, the Commission affirmed the use of a projected test year. In rejecting witness Schultz's approach, the Commission stated:

> The historical test year has the advantage of using actual data for much of rate base, NOI, and capital structure; however, the pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.

Q. Is this finding instructive for the use of a projected test year for Tampa Electric in 2014?

A. Yes, very much so. While I am not aware of any direct challenge to the use of a projected test year for Tampa Electric, as was the case for Gulf, there are intervenor witnesses who indirectly challenge it. They do this by relying on an historical year adjusted for inflation or an average of a series of historical years to place a limitation on costs eligible for recovery. Witness Kollen's use of a "top-down" approach based on 2012 to determine his recommended level of operations and maintenance (O&M) expenses is a good example. This approach and other adjustments recommended by witness Kollen and witness Schultz are essentially reverting to the use of a historical test year for selected issues. The regulatory policy shortcomings of their approach for certain issues are further addressed by me later in my testimony. More importantly, the fallacies of their positions are explained in greater detail by Tampa Electric operational witnesses. These witnesses explain how intervenor adjustments deny them the level of resources needed to reliably and effectively provide services in 2014 and beyond. Their testimony goes from regulatory theory to real world impacts of the intervenor adjustments.

Q. What is your recommendation?

A. I recommend that the Commission reaffirm the use of a projected test year and utilize Tampa Electric's 2014 projections as the basis to set rates in 2014 and beyond. Only if it is determined that the 2014 projections are biased, inherently flawed, or yield unreasonable results, should there be adjustments. It is Tampa Electric's burden to demonstrate that their projections are appropriate and reasonable. However, a mere observation that the 2014 projections are greater than historical escalations or historical averages, as is done by various intervenor witnesses, is not sufficient to reject the projections out-of-hand and impose strict limitations on recoverable costs. As observed by the Florida Supreme Court, the ultimate goal is "to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility." I fear that many of the historically based intervenor adjustments result in artificial limitations on otherwise prudent and necessary costs. As such, these adjustments would be inconsistent with this goal.

CONSTRUCTION WORK IN PROGRESS

Q. What is Construction Work In Progress?

A. Construction Work in Progress ("CWIP") is FERC Account 107 which reflects the total of work order balances for electric plant that is in the process of being constructed.

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

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

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

A. Yes, it should.

Q. How should this be accomplished?

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

Q. Is there a fundamental difference between the two approaches?

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

Q. What are the main reasons why a CWIP project would not qualify for AFUDC?

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

Q. What is witness Chriss recommending for CWIP for Tampa Electric?

A. Witness Chriss recommends that $174.1 million of CWIP be excluded from Tampa Electric's rate base and be denied a return.

Q. How is a return being denied?

A. The $174.1 million represents short-term construction projects which do not qualify for AFUDC under the Commission's rule. If these projects are not included in rate base, Tampa Electric will be denied an opportunity to earn a return on capital that it has deployed to adequately meet its customers' need for service.

Q. Witness Chriss rationalizes his recommended disallowance on the grounds that the $174.1 million is not used and useful. Do you agree?

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

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

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

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

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

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

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

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

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

Q. What were the Commission's findings?

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

> The Commission's currently prescribed

accounting treatment of AFDC was established by Order No. 3143 in Docket No. 6655 issued in 1962. It provides the companies with two options:

a. Charge AFDC on CWIP and not include CWIP in rate base.

b. Not charge AFDC and include CWIP in rate base.

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

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

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

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

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

Q. Has the $174.1 million of CWIP that Tampa Electric is requesting to be included in its rate base ever accrued AFUDC?

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

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

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

Q. Witness Chriss further opines that any inclusion of CWIP in rate base should result in a lower authorized return on equity ("ROE") for Tampa Electric. Do you agree?

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

RECONCILIATION OF RATE BASE AND CAPITAL STRUCTURE

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

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

Q. How is the reconciliation accomplished?

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

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

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

Q. What does witness Gorman recommend in regard to the reconciliation of rate base and capital structure?

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

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

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

Q. Do you agree with his opinion?

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

Q. What gives rise to deferred taxes?

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

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

A. Yes, they do in two ways. First, the impact of accelerated depreciation reverses over time and customers receive the full tax benefit of the depreciation over the life of the asset pay only the amount of income tax expense that is eventually paid to the government.

Second, during the time that the deferred taxes exist on the company's books, the zero cost loan from the government is included in the company's capital structure at zero cost.

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

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

Q. How so?

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

Q. How did the Commission allocate rate base adjustments in Gulf Power Company's last rate proceeding?

A. The Commission did it pro rata for Gulf Power Company. In Order No. PSC-12-0179-FOF-EI, issued on April 3, 2012 in Docket No. 110138-EI, the Commission stated:

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

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

A. Yes, in its Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI, addressing its decision in a recent Florida Power & Light ("FPL") rate proceeding, the Commission stated:

> We are concerned that the double counting of deferred income taxes might result in a violation of tax normalization rules. Per IRC§168(i)(9), tax normalization requires any ratemaking adjustment with respect to a utility's deferred income tax reserves to be consistently applied with respect to rate base, depreciation expense, and income tax expense. Pursuant to IRC§168(f)(2), the consequence of violating the normalization method of accounting is the loss of the ability to claim accelerated depreciation for income tax purposes. Such a normalization violation would result in the loss of the ability to use accelerated tax methods of depreciation. Consistent with prior PSC orders, tax normalization rules, and as discussed in

greater detail below, FPL has properly allocated pro-rata adjustments to all sources of capital.

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

Q. Did such a review take place?

A. Yes, there was a workshop conducted by staff on May 12, 2010.

Q. Were there any changes made by the Commission in its allocation methodology as a result of this workshop?

A. No, not to my knowledge.

<u>OPERATIONS & MAINTENANCE (O&M) EXPENSES</u>

Q. What does witness Kollen recommend in regard to Tampa Electric's O&M expenses?

A. Witness Kollen recommends substantial reductions in Tampa Electric's projected 2014 O&M expenses by two different means, a "top-down" approach and a "bottoms-up" approach. Under his top-down approach, witness Kollen recommends a disallowance of $40.898 million. Under his bottom-up approach, witness Kollen recommends a disallowance of $31.876 million.

Q. What is the basis for witness Kollen's recommended top-down disallowance?

A. Witness Kollen begins with Tampa Electric's 2012 level of jurisdictional O&M expenses of $299.546 million and increases it by a 2-year inflation factor of 4.7 percent to derive his recommended level of 2014 O&M expenses of $313.633 million. He then compares his recommended level to Tampa Electric's 2014 forecasted level of O&M expenses to result in his $40.898 million recommended disallowance.

Q. Is this approach reasonable and appropriate?

A. It is neither reasonable nor appropriate.

Q. Please explain.

A. Witness Kollen's approach is an overly simplistic analysis that cannot be relied upon to accurately establish the amount of O&M expenses necessary to provide service in 2014 and beyond. He blindly establishes 2012 as a representative year upon which mere inflation factors can be applied to establish going forward amounts. He conveniently ignores substantial testimony by Tampa Electric witnesses that 2012 is not representative of normal on-going expense levels and the substantial testimony of Tampa Electric witnesses who support the needs in the 2014 budget. His approach is similar to the Commission's O&M Benchmark and applies the result in a manner never intended. If the Commission were to accept witness Kollen's approach and the recommended disallowance resulting there from, the Commission would be abdicating its responsibility to establish expense levels reasonably necessary to provide service on a going forward basis.

Q. How is witness Kollen's top-down approach similar to the Commission's O&M Benchmark?

A. Witness Kollen's top-down approach is similar in that it takes a base year and escalates it to calculate a benchmark. However, it is also significantly different in both its calculation and, more importantly, in its application.

Q. Please explain how it is different in its calculation.

A. The Commission's O&M Benchmark begins with the level of O&M expenses for a prior year that have been reviewed as part of a rate case. It then escalates this level of O&M expenses by both inflation and customer growth to determine the benchmark level. The analysis also calculates a benchmark by functional areas within the company. In contrast, witness Kollen's approach chooses 2012 as the base year, a non-test year that has not been determined to be reasonable, necessary and reflective of on-going needs. He then only applies an inflation factor and not a factor for customer growth. Neither does his analysis show amounts by function.

Q. Please explain how it is different in its application.

A. The Commission's O&M Benchmark is an analytical tool used by the Commission to better scrutinize expense levels and to give the company an opportunity to justify expense levels which may exceed the benchmark. The Commission has never used the Benchmark as an absolute limitation on the amount of expense determined to be reasonable and necessary on a going forward basis. In contrast, witness Kollen uses his 2012 base year escalated by inflation as an absolute limitation. His approach effectively denies Tampa Electric the opportunity to justify the level of expense it is seeking in the 2014 test year.

Q. On what basis can a utility company justify expenses above a benchmark level?

A. It is the utility company's responsibility to justify these amounts based on its particular facts and circumstances. However, such justifications can be based on a showing that specific expenses are not well gauged by a general inflation factor or that additional expenses are reasonably necessary to meet customer expectations or to meet increased standards and requirements. For example, certain types of expenses may exceed general inflation, such as health care costs, diesel fuel for trucks and other equipment, and certain materials or components that may be subject to high demand and low supply. Examples of increased expenses due to increased requirements would be storm hardening, increased maintenance needed to meet reliability requirements, and increased outage activities needed to optimize plant performance. Such expenses should be evaluated for reasonableness and not summarily rejected if they exceed a base amount escalated for inflation.

Q. Are there similar flaws in witness Kollen's bottoms-up approach?

A. Yes, there are. First, it should be observed that witness Kollen's bottoms-up approach attempts to look at Tampa Electric's O&M expenses with greater granularity and the result is a reduced recommended disallowance, i.e., $31.876 versus $40.898 million. This highlights the fact that witness Kollen's top-down approach cannot be relied upon to yield meaningful results. Nevertheless, some of witness Kollen's recommended disallowances included in his bottoms-up approach contain the same or similar flawed premise as contained in his top-down approach.

Q. What is this flawed premise?

A. The flawed premise is that a prior year escalated for inflation or that an average of a series of prior years without escalation for inflation should be used as a limitation on the amount of expenses allowed as reasonable in the 2014 test year. As used in his top-down approach, witness Kollen escalates Tampa Electric's 2012 distribution O&M expense by inflation to set a limitation on allowable distribution O&M expense, resulting in a recommended disallowance of $5.317 million. Witness Kollen slightly changes his approach for planned maintenance outage expense. Instead of escalating 2012 for inflation, he averages the years 2010 - 2012, without escalation for inflation, to calculate his limitation on allowable planned maintenance outage expense. This approach results in his recommended disallowance of $7.145 million. It is interesting to note that had witness Kollen continued to use the approach wherein 2012 is escalated for inflation, his recommended disallowance for planned maintenance outage expense would have been approximately $800,000 lower.

Q. What is your recommendation for Tampa Electric's allowable level of O&M expenses?

A. I do not have a quantified dollar recommendation. My recommendation is to reject witness Kollen's reliance on a benchmark type approach to place limitations on what otherwise may be necessary and reasonable expense levels. The Commission should continue its practice of using its

O&M Benchmark to scrutinize expenses and consider Tampa Electric's justifications for its 2014 projected expense levels. The goal is to set 2014 expense levels that are reasonable and necessary to provide safe, efficient, and reliable service on a going forward basis.

Q. What consideration do you believe should be given to the level of O&M expenses incurred by Tampa Electric in 2011 and 2012?

A. I think the commission should consider those expense levels as it evaluates the company's proposed level of O&M expenses in the 2014 test year, but should keep those historical years in perspective. Several of the company's witnesses have explained that the company's revenues for 2011 and 2012 were much lower than anticipated due to weather, economic conditions and changes in customer usage patterns. The company responded to these unexpected changes by taking extraordinary steps to reduce O&M expenses to maintain the financial health of the company. I would encourage the commission to evaluate the company's levels of O&M spending in light of what was happening to the company in those years and to refrain from adjusting test year O&M expenses based on comparisons to 2011 and 2012 or averages using those years. The commission would likely be reluctant to use years with higher than normal O&M expenses as a touch point for evaluating test year expenses, and it should be equally reluctant to evaluate test year expenses against years when spending was cut to austere "just get by" levels. The commission's goal should be to approve a sustainable level of O&M spending that will allow the company to provide reasonable and reliable service to its customers. Holding the company to unusually low levels achieved during extreme conditions in some sense amounts to "no good deed going unpunished" and is not in the best long run interests of the customers.

EQUITY RATIO

Q. Does witness Kollen make a recommendation to incentivize Tampa Electric to reduce its equity ratio?

A. Yes, witness Kollen presents two options. His first option is to reduce the equity ratio in this case and to allow 25 percent of the revenue requirement reduction to be added to Tampa Electric's Performance Sharing Plan ("PSP") incentive compensation expense. His second option is to have Tampa Electric reduce its equity ratio in its next rate case, with the understanding that the

Commission would allow a pro forma adjustment in the next case to increase PSP incentive compensation expense by 25 percent of the lower revenue requirement.

Q. Should the Commission accept either of these options?

A. No, the Commission should reject both options. Both are based on a premise that is unsubstantiated and both constitute bad regulatory policy.

Q. How is the premise for these options unsubstantiated?

A. Witness Kollen's premise is that Tampa Electric's current equity ratio is excessive and that a lower equity ratio would reduce Tampa Electric's revenue requirement. Other than referencing witness Baudino's position that Tampa Electric's equity ratio is higher than witness Baudino's comparative group, witness Kollen does not show that Tampa Electric's equity ratio is excessive. The appropriateness of Tampa Electric's equity ratio should be evaluated on Tampa Electric's specific facts and circumstances, such as its overall risk profile and its ability to obtain capital on reasonable terms. It is also unsubstantiated that a lower equity ratio would reduce Tampa Electric's revenue requirement. It is mathematically true that, assuming everything else is equal, a lower equity ratio lowers revenue requirements. However, making such a naïve assumption is not indicative of the real world where revenue requirements are intertwined with a myriad of different factors moving the calculation of revenue requirements in opposite directions. The goal should be a balanced equity ratio that optimizes risk mitigation and revenue requirements. A company's equity ratio is a financial metric closely watched and evaluated by financial analysts. As such, it should not be changed unless there is a compelling reason to do so.

Q. How do witness Kollen's options constitute bad regulatory policy?

A. Both of witness Kollen's options break from the principle that incentives should be implemented to encourage actions that produce mutual benefit. Incentives should not be used to incent actions that do not have a clear mutual benefit or encourage conflicting actions. His options place Tampa Electric's management in an untenable position of choosing between an equity ratio that it believes is appropriate and financial gain for its managers and employees. Furthermore, Tampa Electric's overall compensation program, including PSP, should be set at a level to attract, retain, and motivate employees. To achieve this goal, Tampa Electric targets its overall compensation at the market median. Allowing additional PSP compensation as an incentive could result in excessive compensation.

AMORTIZATION OF SOFTWARE

Q. What does witness Pous recommend for the amortization of software costs?

A. Witness Pous is recommending two separate adjustments. First, he recommends that Tampa Electric's 10 year amortization period be increased to 15 years. Second, he recommends that the historical accumulated amortization reserve be restated (increased) to reflect a 5 year amortization. Witness Pous' recommendations are inconsistent with goals of regulation and are internally inconsistent in rationale and application. The only way they are consistent is that they both inappropriately reduce Tampa Electric's revenue requirements in the current rate case.

Q. How are witness Pous' recommendations inconsistent with goals of regulation?

A. An important goal of regulation is to objectively set amortization rates which best match the amortization period with the expected life of the intangible asset being amortized. This should be done without consideration of whether a change in amortization would affect customer rates (either up or down) in a rate case. Witness Pous' recommendations to restate the amortization reserve and to increase the amortization period going forward appear to be driven by the inappropriate goal of minimizing revenue requirements in the current rate case.

Another goal of regulation is to not only objectively match the amortization period of an intangible asset with its expected life, but also have the annual amortization expense be as consistent and smooth as possible. Specifically in regard to Tampa Electric's Enterprise Resource Planning ("ERP") software, witness Pous' recommendation would have the amortization heavily skewed to the early years of the software's deployment and then greatly diminished over the remaining years of his recommended 15 year life. In contrast, Tampa Electric's proposed amortization would be 10 percent per year over the asset's 10 year expected life. This is graphically depicted for a hypothetical in my Document 3 of my exhibit.

Q. Do you have a position on the appropriateness of a 10 year amortization versus a 15 year amortization?

A. No, I have no position on which amortization period is more appropriate. As I stated earlier, the amortization period should match the expected life of the intangible asset as closely as possible. However, I do have two observations. First, regardless of whether the expected life is 10 years or 15 years, it is obvious that it is not expected to be 5 years and that Tampa Electric was justified to use a longer than 5 year period to amortize the ERP software when it was first deployed. Second, if a 15 year amortization period is used and the actual life is 10, there will be a substantial unrecovered cost at the end of the asset's life. This cost would then have to be recovered by some means, effectively pushing these costs farther out into the future.

INCENTIVE COMPENSATION

Q. Do witnesses Kollen and Schultz take issue with Tampa Electric's incentive compensation programs?

A. Yes, they both address Tampa Electric's PSP and stock compensation programs and they recommend substantial disallowances for each.

Q. What is the nature of their recommended disallowances for Tampa Electric's PSP?

A. Witness Kollen makes a "bottoms-up" adjustment to Tampa Electric's 2014 O&M expenses to disallow $5.034 million of Tampa Electric's PSP expense. The basis for his adjustment ignores the operational part of Tampa Electric's PSP and would limit PSP expense to only the two percent attributable to safety related goals. He once again uses 2012 as his base year and observes that only safety related payouts were made in 2012.

Witness Schultz takes a similar approach and limits PSP expense to the two percent attributable to safety related goals. He recommends a disallowance of $5.987 million attributable to Tampa Electric, in effect allowing only two percent of his recommended payroll expense as PSP. He then further disallows $1,837 of PSP allocated from TECO Energy, for a total disallowance of $7.818 million (jurisdictional). Witness Schultz also offers an alternative recommendation. In his alternative, he eliminates all of the PSP expense attributable to operational goals and then recommends that the remainder be shared equally between stockholders and customers. This results in a total recommended disallowance of

$8.074 (jurisdictional). He further observes that no operational PSP payments were made in the years 2011 and 2012.

Q. What is the nature of their recommended disallowances of Tampa Electric's stock compensation expenses?

A. Both witness Kollen and witness Schultz eliminate all of Tampa Electric's 2014 projected stock compensation expenses. Witness Kollen recommends a disallowance of $5.084 million. Witness Schultz also eliminates stock compensation expenses allocated from Tampa Electric Energy, to result in his total recommended disallowance of $9.715 million (jurisdictional).

Q. Are there any common themes in the positions of witnesses Kollen and Schultz in regard to Tampa Electric's PSP and stock compensation programs?

A. Yes, there are two major ones. First, both witness Kollen and witness Schultz put great emphasis on their observations that no operational related amounts were paid under PSP for the years 2011 and 2012. They use this as a rationale to disallow operational related PSP expense in the 2014 test year. And second, both witness

Kollen and witness Schultz believe that financial incentives benefit stockholder(s) to the detriment of customers. They conclude that the cost of such incentives should be borne by stockholder(s).

Q. Do you agree with their rationale to disallow operational related PSP expense because no such payments were made in the years 2011 and 2012?

A. No, I do not. The real issue is whether the operational goals of the PSP and the projected payouts are reasonable and part of a broader compensation plan designed to adequately compensate and motivate employees. According to Tampa Electric witness Register, that is exactly what the operational goals and the associated payouts do. It is possible and perhaps likely that the years 2011 and 2012 are not good base years in which to conclude that operational PSP expense levels are not needed in 2014 and beyond. It is clear from the testimony of other Tampa Electric witnesses that the years 2011 and 2012 were in the midst of the Great Recession in which Tampa Electric was experiencing a dramatic decrease in expected revenues. This caused Tampa Electric management to reevaluate spending priorities and also caused many PSP goals to be unmet. This does not mean that the goals and the expected PSP expenses are unreasonable for 2014 and beyond. This simply recognizes that under an at-risk performance pay plan, some years will see actual payouts less than budgeted and in some years greater than budgeted. It is the nature of employees having part of their compensation at risk.

Q. Do you agree with witnesses Kollen and Schultz that financial incentives benefit stockholder(s) to the detriment of customers?

A. No, I do not. Financial goals also benefit customers. Regulated utilities are profit making entities (hopefully) and must make a reasonable profit to be sustainable and to access capital when needed and on reasonable terms. This is the means by which customers receive the service that they expect and deserve. A utility earning a reasonable profit is beneficial for both its shareholders and its customers. Therefore, financial goals used to establish compensation levels are also beneficial to customers.

Q. Can you give specific examples of how financial goals benefit customers?

A. Yes, I can. Return on equity ("ROE") is a fundamental measure of financial performance. It represents the earnings (revenues less expenses) as a percentage of equity investment. It can be increased (or its erosion diminished over time) in a number of ways. First, revenues can be increased by serving more customers with the same amount of expenses and investment. Second, expenses can be reduced by serving existing and future customers more efficiently. Third, assets can be utilized more efficiently so that the denominator in the equation (equity capital) is minimized for each dollar of income that is generated. Each of these scenarios (or a combination of them) will increase the ROE and provide added value to customers by increasing the efficiency of utility operations. This is particularly meaningful for regulated utilities which must keep rates fixed in between rate cases.

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

A. Yes, it is. Apparently witness Kollen also agrees with this concept. In his recommendation to achieve a reduction in Tampa Electric's equity ratio, witness Kollen recommends the awarding of greater PSP payments. Of course, as I described earlier, the financial goal of reducing Tampa Electric's equity ratio is misguided and should not be used to award PSP payments.

Q. Should the Commission require a sharing of incentive compensation between customers and stockholder(s) as suggested by witness Schultz in his alternative position?

A. No. The suggestion to share the cost of incentive compensation is misplaced and shifts the true focus of determining the level of compensation expense (or any expense) that should be recovered in rates. A fundamental tenet of sound regulatory policy is to provide recovery of all reasonable and necessary costs incurred to provide service to customers. And a basic principle of ratemaking is to include all such costs as test year expenses in calculating a regulated company's net operating income. Only if the Commission finds that the expenses in question are unreasonable or unnecessary should they be disallowed in calculating the company's revenue requirement.

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

Q. Please explain how their recommendations violate the tenet of recovery of reasonable and necessary costs.

A. Neither witness Kollen nor witness Schultz has presented an analysis of the employment market to determine what amount of compensation is reasonable and necessary to attract the workforce needed to efficiently and reliably run an electric utility. This is in contrast to the testimony of Tampa Electric's witness Register who explains that the overall compensation is reasonable, that it is necessary to attract and retain a qualified workforce, and that it is at or near the median of employee compensation paid by other regulated utilities.

Witness Kollen's and witness Schultz's recommendations are further flawed because they make no analysis of the reasonableness of the net amount of compensation that remains after operational PSP and stock compensation are eliminated. They have not provided any evidence that shows the level of compensation that remains will ensure that Tampa Electric is competitive in the market in terms of its ability to attract and retain qualified employees.

Q. Has the Commission addressed incentive compensation for other Florida utilities?

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

> Tampa Electric's Success Sharing Plan has been in place since 1990 and its appropriateness was

> approved in the company's last rate case in 1992. Lowering or eliminating the incentive compensation would mean Tampa Electric employees would be compensated below the employees at other Companies, which would adversely affect the company's ability to compete in attracting and retaining a high quality and skilled workforce. We therefore decline to do so.

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

The Commission has also approved incentive compensation in three prior rate cases for Gulf, the most recent of which resulted in an order issued in April of last year. Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, In re: Petition for increase in rates by Gulf Power Company. The Commission's finding in the 2001 Gulf rate case contains language similar to the Tampa Electric case:

> To only receive a base salary would mean Gulf employees would be compensated at a lower level than employees at other companies. Therefore,

an incentive pay plan is necessary for Gulf salaries to be competitive in the market. Another benefit of the plan is that 25 percent of an individual employee's salary must be re-earned each year. Therefore, each employee must excel to achieve a higher salary. When employees excel, we believe that the customers benefit from a higher quality of service.

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

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

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

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

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

363 So. 2d 799, 800-01 (Fla. 1978)

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

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

> In determining whether an executive's salary is reasonable compared to salaries paid to other company executives, the comparison must, at a minimum, be based on a showing of similar

duties, activities, and responsibilities in the person receiving the salary.

624 So. 2d 306, 311 (Fla. 1st DCA 1993)

Q. How are these cases related to the disallowance of incentive compensation recommended by witnesses Kollen and Schultz?

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

Witness Kollen's and witness Schultz's analyses are similarly flawed because they have made no attempt to compare the total compensation paid to Tampa Electric employees to the market for similar services, duties, activities and responsibilities. Instead they recommend a portion be disallowed based on how it is paid: Because it is performance-based variable pay, rather than base salary, it is subject to disallowance notwithstanding whether the total amount of compensation is reasonable.

The focus of any disallowance should be how much is paid, not how it is paid.

Q. How do witness Kollen's and witness Schultz's recommendations fail to encourage efficiency or maintain or improve the quality of service?

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

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

A. Accepting witness Kollen's and witness Schultz's recommendations would, by necessity, cause Tampa Electric to rethink its long standing approach to employee compensation. If a significant amount of otherwise valid and reasonable costs are disallowed simply because of the method by which they are paid, Tampa Electric would be justified in implementing a different pay structure. While accepting their recommendations would deny Tampa Electric the opportunity to recover necessary costs currently, adopting a different compensation plan with no at-risk pay and a greater reliance on base pay would presumably eliminate the issue in future rate proceedings. But by moving more salary to base pay, employees don't have to re-earn that pay by meeting goals that typically include efficiency and service objectives. A compensation structure that pays employees regardless of performance diminishes management's leverage to motivate and focus employees on appropriate goals. In essence, the Commission would be substituting its judgment for that of Tampa Electric's management as to how best to motivate and compensate its employees. Consequently, the incentive for Tampa Electric's employees to be motivated and productive would be diminished.

Q. Is it your position that Commission precedent supports the recovery of all of the non-executive performance-based variable pay? And why has this been the precedent in Florida?

A. While the Commission reviews each utility's compensation costs on the facts unique to that utility, the Commission has consistently recognized that incentive compensation/performance-based variable pay, is an accepted and desirable way to achieve corporate goals and to control costs for the benefit of customers. The Commission has also determined that incentive compensation is an appropriate component to include within overall compensation to judge whether the overall compensation paid to employees is reasonable.

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

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

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

Q. Witness Deason, do you understand that witness Schultz is not recommending that Tampa Electric not pay the entire non-executive performance-based variable pay; he is simply recommending that a portion not be recovered in rates?

A. Yes, I understand his recommendation. However, disallowing a reasonable and necessary business expense, or requiring the company to share part of the expense, is nothing more than a backdoor approach to reducing the allowed ROE. Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in rates.

DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. What is the recommendation made by witness Schultz regarding Directors and Officers Liability ("DOL") Insurance?

A. Witness Schultz is recommending the disallowance of $398,974 (jurisdictional) or 50 percent of the cost of DOL insurance premiums.

Q. Do you agree with this recommendation?

A. No, I do not.

Q. Why not?

A. I disagree for reasons similar to the points I made with regard to at-risk incentive compensation. The amount requested by Tampa Electric for DOL insurance is reasonable and is an ordinary and necessary cost of doing business, and as such the entire amount should be recovered in rates.

Q. Why are DOL insurance premiums a necessary and reasonable cost of doing business?

A. DOL insurance is necessary to attract and retain knowledgeable, experienced and capable directors and officers. DOL insurance is purchased for the purpose of protecting the company and its directors and officers from normal risks associated with managing the company. Qualified and capable directors and officers would be reluctant to assume the responsibilities of managing a company without the assurance that their personal assets would be shielded from legal expenses, settlements or judgments arising from lawsuits. The assets of the company are likewise protected from lawsuits that could divert capital to cover any losses. Increasing scrutiny of corporate governance and the related risk exposure of directors and officers make DOL insurance a necessity in maintaining a high quality board and senior management team. Adequate liability coverage gives directors and officers the level of comfort necessary to enable them to make forward-looking decisions that will provide operational and cost-efficiency benefits for customers.

Q. Has the Commission previously addressed the need for DOL insurance?

A. Yes. The Commission's rationale in the People's Gas case and in the last Tampa Electric rate case are instructive regarding the need for DOL insurance:

> DOL Insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers without it. Moreover, ratepayers receive benefits from being part of a large public company, including, among other things, access to capital. In addition, DOL Insurance is necessary to protect the ratepayers from allegations of corporate misdeeds.

Order No. PSC-09-0411-FOF-GU, page 37 issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by People's Gas System.

> We find that DOL insurance is a part of doing business for a publicly-owned company. It is necessary to attract and retain competent

directors and officers. Corporate surveys indicate that virtually all public entities maintain DOL insurance, including investor-owned electric utilities.

Order No. PSC-09-0283-FOF-EI, page 64 issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric company.

Q. The Peoples Gas decision references benefits to ratepayers from a large publicly traded company. What is the significance of this finding?

A. This finding correctly observes that there are benefits to customers by virtue of a company being publicly traded. Publicly traded companies have reporting and corporate governance responsibilities and have access to capital from publicly traded markets. This affords protections and access to capital on reasonable terms (assuming the company's credit metrics are sufficient), which benefits customers. However, being a publicly traded company requires an objective and knowledgeable board of directors. Sufficient DOL insurance is a concomitant necessity for a publicly traded company.

Q. Does Witness Schultz claim DOL insurance is not a necessary and reasonable expense?

A. No, not directly. He characterizes the customer benefits from DOL insurance as being "subjective" and that DOL insurance primarily benefits shareholders.

Q. Do you agree with his characterization?

A. No, I do not. DOL insurance is not designed to benefit shareholders. DOL insurance is designed to protect the officers and directors of the corporation from lawsuits alleging harm from decisions of the officers and directors acting in their official capacity. This is an important distinction for two reasons. First, without adequate DOL insurance, any corporation would find it difficult to attract the best qualified individuals to serve as officers and directors. Second, and perhaps more importantly, it allows officers and directors to make decisions based on their best judgment and not on the goal of minimizing exposure to potential lawsuits. And this second reason is especially applicable to officers and directors of regulated utilities.

Q. Why is this second reason especially applicable to officers and directors of regulated utilities?

A. A regulated utility is in a relatively unique position as compared to typical for-profit companies. To be successful, a regulated utility must meet all of its obligations required by virtue of being a state-sanctioned regulated monopoly and must fulfill its commitments to all stakeholders, including its vendors, employees, creditors, stockholders, customers and regulators. Therefore, truly effective directors and officers must feel free to exercise their best independent judgment to balance all of those sometimes competing interests, without fear of lawsuits threatening their personal assets. It is both good public policy and good regulatory policy to encourage such informed, objective decision making that is enabled to a great extent by DOL insurance.

Q. Why is it good regulatory policy to encourage DOL insurance?

A. It is good regulatory policy to encourage DOL insurance to enable officers and directors to engage in thoughtful, objective decision making that carefully weighs the outcomes and resulting impacts on all stakeholders.

Q. Is there a real-world example of this?

A. Yes, perhaps the best example of this is the Commission's policy of encouraging settlements among the parties on matters in dispute. The best settlements are those where all parties engage in meaningful discussion and agree on sometimes significant concessions. When these concessions are believed to be in the best interest of a regulated utility and its stakeholders, the officers and directors should feel free to exercise this judgment, without the fear of a lawsuit alleging the concessions were too great.

Q. In response to a previous question, you contrasted a regulated utility with a typical for-profit company. Are for-profit companies the only entities that find it necessary and appropriate to purchase DOL insurance?

A. No, many non-profit entities purchase DOL insurance for the same reasons, i.e., to enable them to have qualified officers and directors and to enable those officers and directors to engage in objective decision making. So entities that do not even have stockholders also find it necessary and appropriate to have DOL insurance. This fact is another reason why I disagree with witness Schultz's characterization that DOL insurance is primarily to benefit shareholders.

Q. What would be the result of accepting witness Schultz's recommendation to disallow half of the cost of Tampa Electric's DOL insurance?

A. Witness Schultz characterizes his recommendation as a sharing of costs based on who he believes benefits. As I just described, I believe his opinion on who benefits is incorrect. Nevertheless, the true effect of his recommendation is to disallow one-half of the cost of Tampa Electric's DOL insurance. This is tantamount to saying that one-half of the cost is unnecessary and imprudently incurred. If this is not the effective result, his recommendation violates one of the most basic tenets of regulatory theory, i.e., that all necessary and prudent costs should be allowed to be recovered in rates.

Q. From a policy perspective, what would be the effective outcome of his recommendation?

A. His recommendation would trigger three potential outcomes, none of which is desirable for a regulated utility and its customers. First, the company could simply decide to not have DOL insurance. This would result in the extremely undesirable consequences of which I earlier spoke. Second, the company could decide to not have DOL insurance and pay its officers and directors more to make-up for the greater risk exposure. Presumably the increased costs would then not be shared because they clearly would be prudent and necessary to attract and retain directors and officers and pay them a market level of compensation. And third, the company could retain its DOL insurance and not recover one-half of the cost of doing so.

Q. What would be the bottom-line impact of the third potential outcome?

A. Disallowing a reasonable and necessary business expense, or requiring the company to share part of the expense, is nothing more than another backdoor approach to reducing the allowed ROE. Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in rates.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CHAIRMAN BRISÉ: Okay. I'm trying to see if there's anything else. Staff, are we missing anything?

MS. BARRERA: No, Commissioner.

CHAIRMAN BRISÉ: All right. Thank you very much. So with that in mind -- Ms. Christensen? Sorry.

MS. CHRISTENSEN: And just one point of clarification. When we reconvene on September the 11th to reconsider the settlement, we're not required to bring our witnesses for that day. And if the Commission were to reschedule a hearing for some future date, then you'd just let us know when we would need to bring our witnesses at that time?

CHAIRMAN BRISÉ: That is correct.

MS. CHRISTENSEN: Thank you.

CHAIRMAN BRISÉ: When we, when we reconvene on Wednesday the 11th we are taking up the settlement. And at that point if there's a decision or whatever there is, we will provide further such instruction at that point.

Ms. Purdy.

MS. PURDY: Yes. Thank you, Mr. Chairman.

So just to be clear then, the earliest the hearing could start in the event the settlement is rejected would be presumably the 12th, just for scheduling purposes?

CHAIRMAN BRISÉ: Yes, ma'am.

MS. PURDY: If it's appropriate at this time, similar to what HUA filed last week, I guess if it's appropriate, I'd like to make an oral motion to be excused on Wednesday just for purposes of HUA. Again, HUA strongly supports the settlement and we thank the Commission for granting the motion for continuance today.

Mr. Moyle has kindly volunteered to speak on our behalf on Wednesday, but for our purposes it would be more efficient if we were allowed to be excused.

CHAIRMAN BRISÉ: Sure. I don't, I don't have any issue with that. That's, that's your call to make. Okay? So you, you will be excused on Wednesday.

MS. PURDY: Thank you very much.

CHAIRMAN BRISÉ: Or HUA will be excused on Wednesday.

MS. PURDY: Thank you.

CHAIRMAN BRISÉ: All right. I don't think there's anything further. I see Ms. Barrera.

MS. BARRERA: Commissioners, just a point of clarification. TECO offered to bring certain personnel to explain the settlement on Wednesday to Commissioners, and we will discuss it later as to who they will be bringing.

CHAIRMAN BRISÉ: Sure. Thank you. As always when we discuss a settlement, we always like to have the appropriate people here so that the answer, the questions can be answered so that we can be fully informed as to whether we're going to take a decision at that point or, or later on in time.

So we will reconvene Wednesday morning at 9:30, and at that point we will take up the settlement and stipulation.

MR. BEASLEY: Thank you, Commissioners.

MR. MOYLE: Thank you.

CHAIRMAN BRISÉ: Okay. With that, we stand adjourned.

(Proceeding adjourned at 10:01 a.m.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 10th day of September 2013.

Linda Boles

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