BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

Proceeding No. 14AL-0660E

RE: IN THE MATTER OF ADVICE LETTER NO. 1672 FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE JULY 18, 2014

Proceeding No. 14A-0680E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS ARAPAHOE DECOMMISSIONING AND DISMANTLING PLAN

ANSWER TESTIMONY AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

CLIMAX MOLYBDENUM COMPANY AND CF&I STEEL, LP

NOVEMBER 7, 2014

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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 Climax Molybdenum Company and CF&I Steel, LP.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for Public Service Company of Colorado ("PSCo" or "Company"). I will also address the appropriate capital structure for PSCo and the resulting overall weighted cost of capital. Finally, I will respond to the Direct Testimony of Mr. Robert Hevert, witness for PSCo.

Q. Please summarize your conclusions and recommendations.

A. Based on current financial market conditions, I recommend that the Public Utilities Commission of Colorado ("PUC" or "Commission") adopt an 8.70% return on equity for PSCo in this proceeding. My recommendation is based on the results of two Discounted Cash Flow ("DCF") model analyses. The first DCF analysis incorporates my standard approach, which includes a group of 18 comparison companies and dividend and earnings growth forecasts from the Value Line Investment Survey, IBES, and Zacks. The second analysis incorporates a two-stage DCF analysis using forecasted growth in Gross Domestic Product as a proxy for expected long-term growth in earnings. My second approach is based on the method recently adopted by the Federal Energy Regulatory Commission ("FERC"). I present this analysis because the PUC relied on a multi-stage DCF analysis in Proceeding No. 12AL-1286G. The FERC's two-stage DCF model incorporates three sources of forecasted GDP growth for the second stage of its earnings growth calculation. In my opinion, this analysis provides the PUC with valuable additional information upon which to base its allowed return on equity ("ROE") in this proceeding. Section III of my testimony contains the details of these two DCF approaches. Both approaches have return on equity results that are quite similar.

I also included two Capital Asset Pricing Model ("CAPM") analyses for additional information. I did not incorporate the results of the CAPM in my recommendation, however.

For purposes of this proceeding, I adopt the Company's requested capital structure if the Commission adopts my recommended 8.70% return on equity. If the Commission adopts a higher ROE, then I recommend that the Company's requested common equity ratio be reduced to a level that is closer to the equity ratio for my comparison group.

In Section IV, I respond to the testimony and recommendation of PSCo witness Mr. Hevert. I will demonstrate that Mr. Hevert's DCF analyses overstate the current investor required return on equity for PSCo. In particular, Mr. Hevert's forecast of GDP growth, which he used in his multi-stage DCF analysis, is considerably higher than the forecasted GDP growth from the three independent sources used by the FERC. Mr. Hevert's other methods of estimating the required return on equity also result in excessive returns. I recommend that the Commission reject Mr. Hevert's recommended return on equity of 10.35% in this proceeding.

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. Generally speaking, interest rates have declined over the last 10 years. Exhibit No. RAB-2 presents a graphic depiction of the trend in interest rates from January 2005 through September 2014. 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[1]. In January 2005, the average public utility bond yield was 5.80% and the 20-year Treasury Bond yield was 4.77%. As of August 2014 the average public utility bond yield was 4.37% and represents a decline of 143 basis points, or 1.43% from January 2005. Likewise, the 20-year Treasury bond declined to 3.01% in September 2014, a decline of 1.76% from January 2005.

In 2008, however, world financial markets experienced tumultuous changes and volatility not seen since the Great Depression. As noted in the SBBI 2009 Yearbook,

1 The average utility bond yield for September 2014 was taken from Moody's Credit Trends web site, September 30, 2014.

both large and small company stocks declined around 37% for the year.[2] 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 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.

Beginning in 2009, 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

2 *2009 Ibbotson SBBI Classic Yearbook,* Morningstar, page 11.

between utility bonds and the long-term Treasury bond declined substantially to 1.63%. This is much closer to the historical spread.

Beginning in January 2013, utility bond yields rose throughout the year but began to fall at the beginning of 2014. As of October 31, 2014 Moody's Credit Trends reported that the yield on the average public utility bond was 4.27%. This is not significantly different from the yield at the end of 2012.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit No. RAB-2?

A. Yes. Beginning in September 2011, the Federal Reserve initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist" was designed by the Federal Reserve to lower long-term interest rates and support the economic recovery. On June 19, 2013, the Federal Open Market Committee ("FOMC") issued a press release indicating that it intended to extend "Operation Twist." 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.

More recently, the Federal Reserve began to pare back its purchases of securities. For example, on January 29, 2014 the Federal Reserve stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Federal Reserve continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October. In this press release, the Federal Reserve noted the following:

> To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. The Committee anticipates, based on its current assessment, that it likely will be appropriate to maintain the 0 to 1/4 percent target range for the federal funds rate for a considerable time following the end of its asset purchase program this month, especially if projected inflation continues to run below the Committee's 2 percent longer-run goal, and provided that longer-term inflation expectations remain well anchored.[3]

Q. Since the Federal Reserve's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields so far in 2014?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. The closing yield for the week ending October 31, 2014 was 2.78%, a decline of 74 basis

3 http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm

points since January. Average utility bond yields have followed a similar trend, starting January at 4.72% and declining to 4.27% as of October 31, 2014.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information.[4]

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Federal Reserve will begin to raise short-term interest rates. However, the timing and the level of any such move are not known at this time. It is important to realize that any investor expectations of higher interest rates are already embodied in current securities prices, which include debt securities. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

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

A. The October 31, 2014 Value Line report on the Electric Utility (West) group of companies noted the following:

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4 Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

> Although electric utility stocks have weakened lately, almost all are up, year to date. (Black Hills and ALLETE are two exceptions.) Many have risen by a double-digit percentage, and a few (including Edison International) have soared by more than 20%. Following this solid performance—and a stellar showing in 2013—most electric utility quotations are within their 2017-2019 Target Price Range. Keep in mind that our 3- to 5-year price projections are based on the expectation that interest rates will be significantly above today's level. Our Quarterly Economic Review in Selection & Opinion projects that the rate on the 10-year U.S. Treasury Note will rise to 4.5% by 2018, more than two percentage points above the rate today.

Edison Electric Institute ("EEI") recently reported that the utility industry's average credit rating improved to BBB+ by mid-year 2014.[5] EEI also reported that in early 2014 both S&P and Moody's published industry-level outlooks describing why they expect U.S. regulated utilities to maintain stable credit profiles throughout the rest of the year.[6]

The *2014 Ibbotson SBBI Classic Yearbook* published by Morningstar stated the following with respect to the outlook for utilities in 2014:

> Adding to the sector's attractiveness going into 2014 is its average 4 percent dividend yield, nearly double the average S&P 500 dividend yield and more than 1 percentage point higher than 10-year U.S Treasuries. Our analysis of returns going back 20 years suggests that 10-year U.S. Treasuries could climb to 4 percent from 3 percent today, with little impact on utilities' total returns. We think utilities with 3 percent to 5 percent earnings growth prospects during the next few years offer a compelling risk-adjusted total-return package for any investor.[7]

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5 *EEI Q2 2014 Financial Update*, page 1.

6 *Ibid,* page 5.

7 *2014 Ibbotson SBBI Classic Yearbook,* Morningstar, page 31.

Q. What do you conclude from the aforementioned quotes?

A. Utilities continue to be safe, solid stock choices for investors. Even with uncertainty regarding the Federal Reserve concluding its maturity extension program, utilities' prices have made solid gains since the beginning of the year. Morningstar indicated that interest rates could rise 100 basis points with little effect on utilities' overall return. The current low interest rate environment continues to favor utility stocks.

It appears that the Fed will continue a relatively accommodating stance with respect to monetary policy and has signaled that it does not intend to raise short-term interest rates at this time. The volatile economic conditions that were present in the 2008 - 2009 period are over and the U.S. economy continues to slowly recover from the recession.

Q. What are the current credit ratings and bond ratings for PSCo?

A. Standard and Poor's ("S&P") current credit rating for PSCo is A- and its first mortgage bond rating is A. Moody's current long-term issuer rating for PSCo is A3, with a rating of A1 for its first mortgage bonds. PSCo's credit ratings are above the average utility credit rating of BBB+ as reported by EEI, underscoring the fact that PSCo is a safer, lower risk investment than the average public utility company.

Regarding PSCo's lower risk, the Company had several rate riders approved by the Commission that lower its risk of recovery for certain costs. These riders include:

- Retail Electric Commodity Adjustment ("ECA") - recovers fuel and purchased power costs.

- Purchased Capacity Cost Adjustment ("PCCA") - recovers purchased capacity payments.
- Steam Cost Adjustment ("SCA") - recovers the difference between the Company's actual cost of fuel and the amount of these costs recovered under its base steam service rates.
- Demand Side Management Cost Adjustment ("DSMCA") - recovers demand-side management, interruptible service option credit costs, and performance initiatives for achieving energy savings goals.
- Renewable Energy Standard Adjustment ("RESA") - recovers incremental costs of compliance with the RES.
- Wind Energy Service - service for customers who choose to pay an additional charge to increase the level of renewable resource generation.
- Transmission Cost Adjustment ("TCA") - recovers transmission plant revenue requirements and provides for a return on CWIP outside of rate cases.

Q. Has the Commission acknowledged PSCo's lower risk relative to other utility companies?

A. Yes. In its Decision No. C13-1568, the Commission also noted "the ROE for Public Service should reflect a lower level of risk compared to similar utilities, particularly since the Company uses multiple rate riders for cost recovery to mitigate risk."[8]

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8 Paragraph 36, Decision No. C13-1568, Proceeding No. 12AL-1268G.

III. DETERMINATION OF FAIR RATE OF RETURN

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

A. I employed two Discounted Cash Flow ("DCF") analyses using a group of regulated electric utilities. The first DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. The second analysis presents the FERC's two-stage DCF model as set forth in its Opinion No. 531[9]. I also employed two Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

In this docket, my recommended return on equity is 8.70% for PSCo. This recommendation is consistent with the results from both versions of the DCF model I present in this proceeding.

Q. Why are you presenting the FERC's two-stage DCF analysis in this proceeding?

A. I am presenting this approach to the Commission as a preferable alternative to the multi-stage DCF analysis presented by PSCo witness Mr. Hevert. FERC's recent adoption of the two-stage DCF model in my opinion provides a useful, more straightforward approach to incorporating forecasted GDP growth into the DCF

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9 *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.*, Opinion No. 531 ("Opinion No. 531").

model than the multi-stage model advocated by Mr. Hevert. I understand that in Proceeding No. 12AL-1286G, the Hearing Examiner and the Commission relied upon a multi-stage DCF analysis in arriving at PSCo's allowed ROE of 9.72%. If the Commission chooses to rely upon a form of the DCF model that includes expected GDP growth in the DCF formula, then I recommend the Commission consider and adopt the FERC's two-stage DCF methodology.

Please refer to my Appendix A, which contains a more detailed discussion of the background of the FERC's adoption of the two-stage DCF model as well as the inputs used in the model.

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

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 perhaps some appreciation in the stock's value 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. 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 potential return available by investing in other risk-comparable firms.

Q. What are the major types of risk faced by 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), the amount of operating leverage, and quality of management are all 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. Additional debt means additional variability in the firm's earnings, leading to additional 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 total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's 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.

<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 the discounted present value of future cash flows. 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 typically 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 PSCo?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to PSCo. Since PSCo is a subsidiary of Xcel 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 PSCo.

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 October 2014 issue of AUS Utility Reports, I selected electric and combination electric and gas companies whose bonds were rated A by either Moody's or Standard and Poor's. PSCo currently carries senior secured bond ratings of A from S&P and A1 from Moody's, so using the either/or criterion for a A rating assures that the companies in the comparison group carry bond ratings that are similar to or slightly below PSCo's senior bond ratings.

From that group, I then selected companies that derived at least 50% of total revenue from regulated electric operations, according to AUS Utility Reports, and that had long-term earnings growth forecasts from Value Line and either Zacks or IBES.

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:

- OGE Energy Corp. - affect on stock price from formation of Master Limited Partnership with CenterPoint Energy.
- Pepco Holdings, Inc. - being acquired by Exelon.
- PG&E Corp. - uncertainties of effect on earnings from San Bruno gas pipeline explosion.
- PPL Holdings - spin-off of unregulated energy supply business.
- TECO Energy - pending acquisition of New Mexico Gas Company.
- Wisconsin Energy Corp. - acquisition of Integrys, Inc.

The resulting comparison group of 18 electric companies that I used in my analysis is shown in the table below.

TABLE 1
COMPARISON GROUP

	Company	S&P Bond Rating	Moody's Bond Rating
1	ALLETE, Inc.	A-	A3
2	Alliant Energy Corporation	A-	A2/A3
3	Avista Corporation	A-	Baa1
4	Black Hills Corporation	BBB	A3/Baa1
5	CMS Energy Corporation	BBB+/BBB	A3/Baa1
6	Consolidated Edison, Inc.	A-/BBB+	A3
7	Dominion Resources, Inc.	A-	A3/Baa1
8	Duke Energy Corporation	BBB+	A3
9	Edison International	BBB+	A2/A3
10	Empire District Electric Co.	A-	Baa1
11	IDACORP, Inc.	A-	A3
12	Nextera Energy	A-/BBB+	A2/A3
13	Northeast Utilities	A-	A3/Baa1
14	Pinnacle West Capital Corp.	BBB	A3/Baa1
15	Portland General Electric Company	A-	A3
16	Southern Company	A	A3/Baa1
17	Westar Energy, Inc.	A-	A3/Baa1
18	Xcel Energy Inc.	A-	A3

Source: AUS Monthly Utility Report, October 2014

This is the comparison group I used for my standard constant growth DCF model and the FERC two-stage DCF model.

Q. Did you follow the FERC's guidelines for selecting your comparison group?

A. No. The FERC's group selection criteria are quite specific, as I described in Appendix A. In this proceeding, I chose to use my standard method of selecting companies for the comparison group. However, I did follow the FERC's guidelines for calculating the dividend yield, expected dividend yield, earnings growth, and forecasted growth in GDP. I will explain this in more detail later in my testimony. The following sections will separately explain and describe my standard constant growth DCF approach and the FERC's two-stage DCF approach.

Constant Growth DCF

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. This is also consistent with the FERC's practice. The six-month period I used covered the months from May through October 2014. 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 comparison group is 3.68%. These calculations are shown in Exhibit No. RAB-3.

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.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Expanded Edition. 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 important 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 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. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance[10].

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 one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Page 1, Columns (1) through (5) of Exhibit No. RAB-4 shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from IBES and Zacks. In my analysis I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only sources of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with the three earnings growth forecasts.

10 In his Direct Testimony, PSCo witness Mr. Hevert referred to these forecasts as First Call.

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

A. To estimate the expected dividend yield (D_1), 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.

Exhibit No. RAB-4 presents my standard method of calculating dividend yields, growth rates, and return on equity for the comparison group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 3.68% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the group under consideration. The calculations of the resulting DCF returns on equity for both methods are presented on page 2 of Exhibit No. RAB-4. Please note that Zacks did not have earnings growth rate estimates for ALLETE, Avista Corp., and Black Hills Corp. For these companies I substituted the corresponding IBES growth rates.

Q. What are the results of your constant growth DCF model?

A. The DCF results for the constant growth DCF approach are shown on page 2 of Exhibit No. RAB-4. For the average growth rates, the results range from 8.60% to 8.88%, with the DCF ROE using the average of these results being 8.71%. Using the median growth rates, the results range from 8.26% to 9.28%, with the average of these results being 8.63%.

FERC Two-Stage DCF Model

Q. How did you utilize your data sources to estimate growth rates for the comparison group using the FERC's two-stage DCF formulation?

A. Exhibit No. RAB-5 presents the growth rate calculation for the comparison group using the FERC's two-stage growth calculation. Column (5) presents the IBES growth rate for each company, Column (6) presents the GDP growth forecast of 4.36%, and Column (7) shows the two-stage weighted growth rate. The FERC two-stage method gives a 2/3 weighting to the IBES growth rate and a 1/3 weighting to forecasted GDP growth.

Exhibit No. RAB-6 shows the calculation of forecasted GDP growth. Based on my understanding of the FERC's Order No. 531 I used three sources of GDP forecasts: IHS Global Insight, the Energy Information Administration ("EIA"), and the Social Securities Administration ("SSA") Trustees Report. Please see Appendix A for a detailed description of each of these three sources and how they are used in the FERC's two-stage DCF model.

Q. Please explain how you calculated the return on equity.

A. The expected dividend yield for each company in the comparison group is shown in Column (4) of Exhibit No. RAB-5 and is the same calculation I used for the expected dividend yield in my constant growth DCF analysis and is consistent with the FERC's approach. The weighted growth rate is then added to the expected dividend yield for the return on equity numbers shown in Column (8). I calculated the average and median ROE for the comparison group. The average DCF result is 8.48% and the median DCF result is 8.69%.

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 all risks specific to a particular company and be 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.[11] There is evidence that beta is not the primary factor in determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its usefulness.

In the final analysis, 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 investor-required returns. Of course, the

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11 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.

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 October 15, 2014. 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 as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit No. RAB-7. I included both average and median earnings and book value growth rates. The estimated market returns using Value Lines market data range from 11.16% to 12.88%. The average of these three market returns is 11.98%.

Q. Is this a change to how you calculated expected market return in the past?

A. Yes. In my past testimonies I simply used the average expected growth rates for earnings and book value from Value Line in calculating an expected market return. However, using three alternative formulations of expected market returns provides a more robust CAPM formulation. Further, using median growth rates is a valuable additional method of estimating the central tendency of Value Line's large data set. FERC also evaluates median growth rates in its DCF return on equity and so adding median growth rates is consistent with that approach.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2014 Classic 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-8 presents the calculation of the market returns using the historical data.

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 April through September 2014. This was the latest available data from the Federal Reserve's Selected Interest Rates (Daily) H.15 web site during the preparation of my Direct Testimony. 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. 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 return on equity may be estimated.

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 comparison group is 0.73.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 9.20% - 9.58%. Using historical risk premiums, the CAPM results are 6.60% - 8.06%. The detailed calculations and results are presented in Exhibit No. RAB-7 and Exhibit No. RAB-8.

Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 2 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 2
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	8.88%
- Low	8.60%
- Average	8.71%
Median Growth Rates:	
- High	9.28%
- Low	8.26%
- Average	8.63%
FERC Two-Stage DCF:	
- Average	8.48%
- Median	8.69%
CAPM:	
- 5-Year Treasury Bond	9.20%
- 20-Year Treasury Bond	9.58%
- Historical Returns	6.60% - 8.06%

Q. What is your recommended return on equity for PSCo?

A. I recommend that the Colorado PUC adopt an 8.70% return on equity. My recommendation is consistent with the average DCF results from my constant growth DCF model and with the median result from the FERC two-stage DCF model. Based on current market evidence, an 8.70% return on equity is fair and reasonable for an A rated, lower risk electric utility company like PSCo.

Q. Please comment on the use of GDP growth as a proxy for long-term growth in earnings for regulated utility companies.

A. I do not believe that investors necessarily rely on forecasts of GDP growth as proxies for earnings growth for regulated utility companies. Instead, investors are much more likely to rely upon analysts' forecasts of earnings and dividend growth that are utility specific. However, for purposes of this proceeding I have presented the FERC's two-stage DCF model as an alternative for the PUC to consider because the Hearing Examiner and the Commission relied upon a multi-stage DCF model in Proceeding No. 12AL-1268G.

In my opinion, the FERC's two-stage approach is a simpler and more straightforward way to estimate the investor-required rate of return than the multi-stage DCF model presented by PSCo witness Mr. Hevert. As I will explain in more detail in Section IV, it is highly unlikely that investors would employ the complicated series of assumptions and calculations embodied in Mr. Hevert's multi-stage DCF model.

More importantly, however, the three independent GDP growth forecasts used in the FERC's two-stage DCF model are significantly lower than the GDP forecast used by

Mr. Hevert. Mr. Hevert's higher GDP forecast, which is based on historical growth in GDP, led to an overstatement of his multi-stage DCF results. Therefore, I strongly recommend that the Commission use the independent GDP growth forecasts I have included in my testimony if it chooses to rely upon a two-stage or multi-stage DCF analysis in this proceeding.

Finally, I recommend that the PUC adopt my constant growth DCF model in this proceeding. My constant growth model employs analysts' forecasts of dividend and earnings growth that investors rely upon and is more likely to reflect investor expectation than a dividend/earnings growth forecast based on forecasted GDP growth.

Q. Your forward-looking CAPM results are higher than your DCF results. Does this suggest that your DCF results are understated?

A. No. In fact, the forward-looking CAPM results are likely overstated.

Q. Why is this the case?

A. I reviewed the summary statistics from the Value Line Investment Analyzer from which I took the median and average earnings and book value growth rates. This summary shows both high and low growth rates for the Value Line data set. For earnings growth, the high growth rate was 531.43% and the low growth rate was minus 23.5%. In my opinion, it is likely that unsustainably high growth rates could be skewing the average earnings and book value growth estimates. Thus, the median growth rates are probably more reasonable indices of central tendency than the average growth rates shown on page 2 of Exhibit No. RAB-7. Using mean growth rates results in a market return of 11.16% compared to 12.88% using average growth rates. I have included the market return of 12.88% in the average market return calculation, but in my opinion this overstates the CAPM market return and the CAPM return on equity results somewhat. For this reason, historical risk premiums should also be used to frame the range of CAPM results in this proceeding.

Q. What is your recommended weighted cost of capital?

A. My weighted cost of capital is based on the capital structure recommended by PSCo witness Ms. Schell. Table 3 below presents my weighted cost of capital.

TABLE 3
Weighted Cost of Capital

	Pct.	Cost Rate	Weighted Cost
Long-term Debt	44.00%	4.68%	2.06%
Common Equity	56.00%	8.70%	4.87%
Total	100.00%		6.93%

Q. How does the Company's requested capital structure compare with the capital structure of your comparison group?

A. Table 4 below presents the 2013 equity and debt ratios for the companies in my comparison group as well as the group average capital structure components. These numbers were taken from the most recent Value Line reports for each company. PSCo's requested 56% common equity ratio is significantly higher than the comparison group's average equity ratio of 48.7%.

TABLE 4
Comparison Group Capital Structure

	Common Equity	Preferred Equity	Long-term Debt
ALLETE, Inc.	55.4%	0.0%	44.6%
Alliant Energy Corporation	50.8%	3.1%	46.1%
Avista Corporation	48.6%	0.0%	51.4%
Black Hills Corporation	48.4%	0.0%	51.6%
CMS Energy Corporation	32.2%	0.3%	67.5%
Consolidated Edison, Inc.	53.9%	0.0%	46.1%
Dominion Resources, Inc.	37.3%	0.8%	61.9%
Duke Energy Corporation	52.0%	0.0%	48.0%
Edison International	46.2%	8.1%	45.7%
Empire District Electric Co.	50.2%	0.0%	49.8%
IDACORP, Inc.	53.4%	0.0%	46.6%
Nextera Energy	42.9%	0.0%	57.1%
Northeast Utilities	54.8%	0.9%	44.3%
Pinnacle West Capital Corp.	60.0%	0.0%	40.0%
Portland General Electric	48.7%	0.0%	51.3%
Southern Company	45.8%	2.7%	51.5%
Westar Energy, Inc.	50.0%	0.0%	50.0%
Xcel Energy Inc.	46.7%	0.0%	53.3%
Averages	48.7%	0.9%	50.4%

It is evident from Table 4 that PSCo's equity ratio greatly exceeds the average equity ratio of the comparison group. This suggests that PSCo's lower financial risk relative to the comparison group should result in a lower required return on equity by investors in PSCo. However, for purposes of this case, I will recommend an ROE for PSCo consistent with the ROE results from the comparison group. This underscores the reasonableness of my ROE recommendation for PSCo in this proceeding.

Q. If the Commission decides on a higher return on equity than your recommendation of 8.70%, should the Company's requested equity ratio be adjusted?

A. Yes. If the PUC allows a higher ROE than my recommended 8.70%, then the Company's requested equity ratio of 56% should be reduced. One reasonable way to make this adjustment would be for the Commission to reduce PSCo's equity ratio by two percentage points for every 0.50% increase in the ROE over 8.70%. So for example, if the Commission adopted a ROE of 9.20%, the Company's equity ratio could be reduced by 2% to 54.0% of investor supplied capital.

IV. RESPONSE TO PSCO 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 four methods to estimate the investor required rate of return for PSCo: (1) the constant growth DCF model, (2) a multi-stage DCF model, (3) the CAPM, and (4) the bond yield plus risk premium model.

With respect to the DCF model, Mr. Hevert developed two proxy groups, one consisting of electric companies and one consisting of combination electric and gas companies. Mr. Hevert also estimated the DCF ROE on both groups combined. Mr. Hevert used 30-day, 90-day, and 180-day average stock prices ending April 15, 2014 to estimate the dividend yield for the proxy companies in all three groups and for his constant growth and multi-stage DCF models.

For his constant growth DCF approach, he used Value Line, First Call, and Zacks for the investor expected growth rate. For the three proxy groups, Mr. Hevert's mean growth rate ROE results ranged from 9.51% to 9.76%.

Regarding his multi-stage DCF analysis, Mr. Hevert used the same proxy groups. His multi-stage growth rate was based on a model that was relied upon by the Hearing Examiner and the Commission in Proceeding No. 12AL-1268G. The results for this method using the mean growth rate for all three groups ranged from 9.92% to 10.32%.

With respect to the CAPM, Mr. Hevert's results ranged from 10.13% to 12.70%.

Finally, Mr. Hevert's formulation of the bond yield plus risk premium approach resulted in a ROE range of 10.14% to 10.39%.

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for PSCo of 10.20% to 10.70%, concluding that the cost of equity for PSCo is 10.35%.

Constant Growth DCF Analyses

Q. What are you conclusions with respect to Mr. Hevert's constant growth DCF model?

A. First and foremost, Mr. Hevert's constant growth DCF analysis suffers from stale data. Mr. Hevert employed 30-day, 90-day, and 180-day stock price data ending April 15, 2014. The Commission simply cannot rely on any DCF analysis with stock prices so out of date. Mr. Hevert needs to update his stock price data if PSCo expects the Commission to place any weight at all on his ROE recommendation.

Q. Did you compare the dividend yields of the companies in his proxy group to the more current dividend yields you used for the companies in your comparison group?

A. Yes. Table 5 below compares six-month dividend yields for companies that Mr. Hevert and I have in common in our respective utility groups. This comparison shows that more recent dividend yields are lower than those Mr. Hevert presented in his Direct Testimony.

TABLE 5
Dividend Yield Comparison - Common Companies
Hevert Combined Proxy Grp. & Baudino Comparison Grp.

	Baudino Group	Hevert Group
Alliant Energy Corporation	3.52%	3.92%
Black Hills Corporation	2.86%	2.97%
CMS Energy Corporation	3.60%	3.95%
Duke Energy Corporation	4.29%	4.50%
Empire District Electric Co.	4.08%	4.49%
IDACORP, Inc.	3.09%	3.32%
Nextera Energy	3.00%	3.35%
Pinnacle West Capital Corp.	4.10%	4.16%
Portland General Electric	3.35%	3.67%
Southern Company	4.75%	4.84%
Westar Energy, Inc.	3.88%	4.31%
Average	3.68%	3.95%

Q. Are Mr. Hevert's earnings growth forecasts also out of date?

A. Yes, and some of the growth forecasts used in Mr. Hevert's constant growth DCF model are significantly higher than more recent forecasts. For example, referring to Attachment No. RBH-1, page 9 of 9, Mr. Hevert used a Value Line earnings growth rate of 13.0% for Black Hills Corp. The most recent Value Line report shows an earnings growth rate forecast of 9.5% for Black Hills, as shown on my Exhibit No. RAB-4, page 1 of 1. Portland General Electric's First Call growth rate has also declined from 10.89% in Mr. Hevert's Attachment No. RBH-1 to 7.80% as shown in my Exhibit No. RAB-4.

Q. Did Mr. Hevert's correctly calculate the median ROE for his constant growth DCF results shown in Attachment No. RBH-1?

A. He definitely did not correctly calculate the constant growth ROE correctly using the median values from his growth rate sources. Referring again to Attachment No. RBH-1, page 9 of 9, the median growth rates from Mr. Hevert's three sources of analysts forecasts range from 4.50% to 4.85% as shown in Columns (5) through (7). However, the median of the average growth rates shown in Column (9) is 5.46%, which is significantly higher than the median values shown in Columns (5) through (7). This is because Mr. Hevert used the median of the average of all three growth rate sources in calculating the median growth rate for the group, rather than the average of the median values in Columns (5) through (7). The 5.46% value used by Mr. Hevert is the average growth rate for Great Plains Energy, Inc., which is the average of his three analysts' growth rates for that company. All of the growth rates for Great Plains Energy, Inc. are above the median values for the group. This caused an overstatement of the average median growth rate for his Combined Proxy Group.

To put it simply, Mr. Hevert did not use the median growth rate values shown in Columns (5) through (7) of Attachment No. RBH-1 in his ROE calculations.

Q. What is the correct way to use the median earnings growth rate values shown in Mr. Hevert's Attachment No. RBH-1?

A. I recommend that the median values be averaged and incorporated into a constant growth rate formula as follows:

Average Combined Proxy Group Dividend Yield		4.01%
Median Earnings Growth Rates (from Attachment No. RBH-1):		
Zacks Median Earnings Growth	4.85%	
First Call Median Earnings Growth	4.60%	
Value Line Median Earnings Growth	4.50%	
Average		4.65%
Expected Dividend Yield		4.10%
Constant Growth DCF ROE		***8.75%***

This calculation properly reflects the median growth rates from Attachment No. RBH-1. The constant growth DCF result is quite close to my recommended 8.70% ROE for PSCo in this proceeding.

Q. Could the double-digit growth rates contained in Mr. Hevert's analysis result in an inflated ROE estimate?

A. Yes. Mr. Hevert's proxy groups contain several double-digit growth rates than inflate the average growth rate results for his groups. For this reason, it is important to consider the median growth rates as an alternative, and perhaps more accurate, measure of central tendency for investor expected growth rates.

Q. Should Mr. Hevert have included dividend growth forecasts in his constant growth DCF analyses?

A. Yes. The DCF model uses expected cash flows in the form of dividends to estimate the investor required return on equity. Earnings growth forecasts are used as proxies for dividend growth, but Value Line also includes a forecast of dividend growth in its reports on the companies it follows. Exhibit No. RAB-4 shows that forecasted dividend growth is lower than expected earnings growth, and this needs to be factored into the overall expected growth component of the constant growth model. I weighted the Value Line dividend growth forecast 25%, or one quarter, and weighted three earnings forecasts 75%, or three quarters, in my growth rate calculations. In my opinion, this gives reasonable weight to a forecast of dividend growth, while placing primary emphasis on earning growth forecasts.

Multi-stage DCF Model

Q. Please summarize the components of Mr. Hevert's multi-stage DCF model.

A. Mr. Hevert described the structure and the inputs for his multi-stage DCF model on pages 31 through 36 of his Direct Testimony. Mr. Hevert testified that he used the approach that was approved by the Hearing Examiner and the Commission in Proceeding No. 12AL-1268G. The main elements of Mr. Hevert's multi-stage DCF analyses are as follows:

- 30-day, 90-day, and 180-day average stock prices.
- First stage of growth based on the average earnings growth rates from Value Line, Zacks, and First Call.
- A transition period from near-term to long-term growth.
- Long-term growth estimated using GDP growth based on historical real GDP growth from 1929 through 2013 and a forecasted inflation rate.
- Expected dividend in the final year divided by solved cost of equity less long-term growth rate.
- Payout ratio assumptions based on Value Line for the first stage, a transition period, and a long-term expected payout ratio.

Q. As a practical matter, is it likely that investors use the multi-stage model presented by Mr. Hevert?

A. No. In my opinion, it is highly unlikely that investors would employ the complicated structure and set of assumptions used by Mr. Hevert. Other than his reliance on the Commission's findings in Proceeding No. 12AL-1268G, Mr. Hevert presented no evidence whatsoever that investors use such a model in forming their required return for an electric utility like PSCo. He presented no evidence that investors use GDP growth in their evaluation of expected growth in dividends and earnings for electric utility companies. Neither did he show that investors utilize his assumptions regarding the transition period or payout ratio forecasts.

Q. If the Commission uses a multi-stage DCF model with GDP growth as a component of expected dividend growth, would you recommend using the FERC's two-stage model?

A. Yes, most definitely. I understand that the Commission relied upon a multi-stage DCF analysis in Proceeding No. 12AL-1268G. Nevertheless, I recommend that the Commission use the FERC's two-stage DCF if it wishes to incorporate GDP growth into the expected growth in dividends. The FERC's model has the virtue of simplicity and is easily understandable. It does not require complex assumptions and forecasts of transition periods and payout ratios. It does rely on independent forecasts of nominal GDP growth, two of which are publicly available.

Most important in this regard, these independent sources are forecasting nominal GDP growth to be substantially lower than the forecast used by Mr. Hevert (4.36% vs. Mr. Hevert's forecast of 5.70%). If the Commission chooses to use Mr. Hevert's or Staff's multi-stage approach, I recommend using the independent forecasts of GDP that I have presented in Section III of my testimony.

Q. Does Mr. Hevert's multi-stage DCF analyses also suffer from stale data?

A. Yes. All of Mr. Hevert's inputs need to be updated with more recent stock price and growth rate data.

Q. Beginning on page 36 of his Direct Testimony, Mr. Hevert discusses the need for a flotation cost adjustment. Are flotation costs a legitimate consideration for the Commission's determination of ROE in this proceeding?

A. No. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as well as broker fees and discounts. Mr. Hevert recommended that the PUC consider adding an adjustment of 14 basis points, or 0.14%, to recognize flotation costs.

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. Adjusting the dividend yield by a 0.14% flotation cost adjustment 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.

Further, Mr. Hevert noted on page 38 of his Direct Testimony that Xcel Energy recently issued $225 million of common equity and that its five-year capital expenditure program would be funded by an additional $700 million of common equity. However, in a September 17, 2014 presentation to the 2014 Power & Gas Leaders Conference, Xcel Energy stated on page 29 that $175 million of equity was issued in the first half of 2014 and that no further equity (beyond DRIP and benefit programs) is expected to the issued through 2018. I have included this page in Exhibit No. RAB-9. This recent presentation contains updated information that is inconsistent with Mr. Hevert's testimony regarding Xcel Energy's issuance of common equity. The Commission should reject Mr. Hevert's testimony on this point.

Q. Beginning on page 39 of his Direct Testimony, Mr. Hevert rejected consideration of his mean low DCF results. Is rejecting the mean low results from his DCF analyses appropriate?

A. No. In fact, Mr. Hevert's mean low results are more indicative of current investor required returns than his mean growth and high growth rate results. As I described earlier in my testimony, given PSCo's relatively lower risk operations and the current low interest rate environment, Mr. Hevert's recommended 10.35% is simply not supportable. Further, Mr. Hevert's DCF results are inflated by high double-digit growth rates, stale stock price data, and an overstated GDP growth forecast.

CAPM

Q. Briefly summarize the main elements of Mr. Hevert's CAPM approach.

A. On page 45 of his Direct Testimony, Mr. Hevert testified that he used estimates of the yield on 30-year Treasury Bonds as proxies for the risk-free rate based on two sources of information: the term structure of the current yield curve and consensus projections of the 30-year Treasury yield for the years 2014 and 2015. Using these sources, Mr. Hevert's risk-free rate ranged from 3.72% to 4.30%. Mr. Hevert did not consider any shorter maturity bonds, such as the 5-year Treasury note.

Mr. Hevert then calculated ex-ante measures of total market returns using data from Bloomberg and Value Line. Total market returns from these two sources were 13.91% market return using Bloomberg data and a 12.31% return using Value Line data.

Mr. Hevert used three different estimates for beta: Bloomberg, Value Line, and Mr. Hevert's calculation of beta for the 12-month period ending April 15, 2014.

Using these inputs, Mr. Hevert's CAPM ROE ranged from 10.13% to 12.70%.

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

A. Definitely not. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yields used by Mr. Hevert are speculative at best and may never come to pass. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates and bond yields 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.

Most importantly, the 30-year Treasury yields used by Mr. Hevert are totally out of line with current 30-year yields. For the week ending October 24, 2014 the yield on the 30-year Treasury bond was 3.01%. Compare this current yield with the forecasted yields used by Mr. Hevert, which range from 3.72% - 4.30%. These forecasted yields contribute to inflated ROE results for Mr. Hevert's CAPM. I strongly recommend the PUC reject the use of forecasted Treasury yields in this proceeding.

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 9.20%. This is much lower than any of the CAPM estimates provided by Mr. Hevert.

Q. Is Mr. Hevert's 12-month beta calculation appropriate for use in the CAPM?

A. No. The 3 - 5 year time periods used by Value Line and Bloomberg are more appropriate because beta should measure the investor expected beta in the longer run. Using longer historical periods for the beta calculation can smooth out market fluctuations and other situations that may occur only in a given year. One 12-month period like the one Mr. Hevert used is simply too short a span of time to reliably measure the investor expected beta over the long run.

Q. Please comment on Mr. Hevert's use of Bloomberg and Value Line earnings growth estimates for the S&P 500.

A. Mr. Hevert used earnings growth estimates from these two sources to estimate the expected market return for his CAPM. However, if forecasted GDP growth is used, then both Mr. Hevert's and my own market return estimates would fall significantly. For example, the average growth rate for the S&P 500 companies using Value Line's data from Attachment No. RBH-4, pages 8 through 14 is 11.74%. Forecasted GDP growth from my Exhibit No. RAB-6 is 4.36%. Obviously, using 4.36% as a proxy for long-term growth for the S&P 500 companies would reduce Mr. Hevert's market return of 12.31% and 13.91% quite substantially. This would also apply to my forward-looking CAPM analyses as well.

__**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 electric and gas utility companies and 30-year Treasury bond yields from January 1980 through April 15, 2014. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. Applying the regression coefficients to the average risk premium and using the projected 30-year Treasury yields I discussed earlier, Mr. Hevert's risk premium ROE estimates range from 10.14% to 10.39%.

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 yields for the same reasons I described in my response to Mr. Hevert's CAPM approach.

Other ROE Considerations

Q. Beginning on page 58 of his Direct Testimony, Mr. Hevert discussed PSCo's capital spending program and suggested that the mean ROE results do not necessarily provide an appropriate estimate of the Company's cost of equity. Do you agree?

A. No. The Commission should not increase PSCo's ROE due to its capital spending program.

First, my ROE analyses do not support an ROE above 8.70% for PSCo in today's capital markets. In this low interest rate environment, Mr. Hevert's 10.35% recommended 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 A/A credit ratings. By estimating the cost of equity using companies with similar bond and credit ratings, the resulting ROE will need no further upward adjustment.

Third, it is important to note that PSCo's 56.0% equity ratio is far higher than the average common equity ratio of my comparison group and is also higher than the mean and median equity ratios of Mr. Hevert's proxy groups. PSCo's higher equity ratio, other things being equal, reduces its financial risk vis-à-vis our respective utility groups.

Q. Has Xcel Energy provided information regarding the risks of its capital expenditure program and the risk of its regulated electric utility operations?

A. Yes. I obtained the aforementioned presentation from Xcel Energy's web site entitled *Well Positioned for the Future*, Wolfe Research, 2014 Power and Gas Leaders Conference, September 17, 2014. There are a number of important aspects of this presentation that I would like to present to the Commission for its consideration. These aspects are:

- Xcel Energy's presentation stated that it had a "[l]ow risk CapEx growth plan" with "no external equity needs" (page 3)
- Earnings and dividend per share growth of 4% - 6% (page 3).
- A low risk $14.1 billion capital investment plan that "drives attractive rate base growth" (pages 5 and 24).
- Regulatory certainty through the implementation of multi-year plans, including Colorado (page 16).
- "Operational excellence" that includes investing in capital to reduce O&M expenses (page 18).
- New equity for its $14.1 billion capital expenditures expected to be only $175 million issued in the first half of 2014 and "no further equity (beyond DRIP & benefit programs) is expected to be issued through 2018 ..." (page 29).

I have included the pages from this presentation in my Exhibit No. RAB-9. Recurring themes in this presentation are Xcel Energy's low risk capital expenditure plan and the minimal amount of additional new equity expected to finance it through 2018. In my opinion, these points are at odds with Mr. Hevert's discussion of the additional risks posed by PSCo's capital expenditure program.

Q. Beginning on page 63 of his Direct Testimony, Mr. Hevert discussed current Federal Reserve policy and its effect on the required return on common equity. Please respond to Mr. Hevert's discussion.

A. I addressed current Federal Reserve policy in detail in Section II of my testimony. The salient points with respect to the required return on equity is as follows:

- The Federal Reserve is continuing an accommodative monetary policy that supports low interest rates.
- This policy will continue even after the Federal Reserve's maturity extension program is concluded, according to recent Federal Reserve statements I quoted in Section II.
- Although the Federal Reserve has significantly reduced and finally concluded its bond purchases this year, interest rates have actually declined since the beginning of the year.

In the current economic environment, utility stocks have fared well. From January 1 through October 31, 2014, the Dow Jones Utility Average increased from 490.31 to 596.93, a 21.75% increase. This increase corresponds to the decline in interest rates throughout the year.

It bears repeating here that any investor concerns with respect to the course of future interest rates are already embedded into current securities prices, including stock and bond prices. As such, the median and average DCF ROE results I presented in my testimony fairly and accurately reflect investor-required returns.

Q. Does this complete your Direct Testimony?

A. Yes.

APPENDIX A

DESCRIPTION AND BACKGROUND FOR FEDERAL ENERGY REGULATORY COMMISSION'S TWO-STAGE DCF GROWTH RATE

In this proceeding, I have presented to the Colorado Public Utilities Commission a two-stage Discounted Cash Flow ("DCF") model that was recently adopted by the Federal Energy Regulatory Commission ("FERC"). In a news release dated June 19, 2014 the FERC stated that it was adopting a new methodology for determining the rate of return on equity for jurisdictional electric utilities. The news release also stated that the new method incorporates both short-term and long-term measures of growth in dividends and that the FERC was instituting a paper hearing on the appropriate long-term growth rate to use. In natural gas and oil pipeline proceedings, the FERC uses growth in GDP as a measure of long-term growth.

In its Opinion No. 531[1], the FERC discussed the specifics of the two-stage DCF model it was adopting. Paragraph 17 of the Opinion noted that the two-step DCF methodology used by the FERC for gas and oil pipelines contained the following components:

- Security analysts' five-year forecasts published by the Institutional Brokers Estimate System (IBES) or a comparable source weighted by two-thirds in the growth rate calculation.
- Forecasts of long-term growth of the economy as a whole, as reflected in Gross Domestic Product ("GDP") weighted by one-third in the growth rate calculation.

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1 Docket No. EL11-66-001

With respect to the GDP forecasts, FERC noted that it used three sources: The Energy Information Administration ("EIA"), the Social Securities Administration ("SSA"), and IHS Global Insight. In its Opinion No. 531, paragraph 43, the FERC did reopen the record in that proceeding for purposes of taking evidence as to the appropriate long-term growth projection to use under the two-step DCF methodology.

Please refer to Exhibit No. RAB-6 for the calculation of the average GDP forecast from the three sources currently used by the FERC in gas and oil pipeline proceedings. This calculation is the same as in the Direct Testimony I filed in FERC Docket Nos. ER13-1508-001 et. al. The IHS Global Insight forecast was taken from the Direct Testimony of William Avera and Adrien McKenzie, witnesses for Entergy Services, Inc. in that docket. The IHS Global Insight forecast is only available by subscription. The EIA and SSA forecasts are publicly available from those agencies on their respective web sites. The calculation in Exhibit No. RAB-6 follows the calculation used by Dr. Avera and Mr. McKenzie and, to the best of my knowledge, also follows the FERC's approach.

Paragraph 21 of Opinion No. 531 explained the FERC's reasoning for using a two-thirds weight for the short-term earnings forecasts and a one-third weight for GDP growth. This weighting was adopted by the FERC in Opinion No. 414-A in which the FERC explained:

> While determining the cost of equity nevertheless requires that a long-term evaluation be taken into account, long-term projections are inherently more difficult to make, and thus less reliable, than short-term projections. Over a longer period, there is a greater likelihood for unanticipated developments to occur affecting the projection. Given the greater reliability of the short-term projection,

> we believe it is appropriate to give it greater weight. However, continuing to give some effect to the long-term growth projection, will aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy.[2]

FERC's Opinion No. 531 was issued in a proceeding involving a group of transmission companies, namely, the New England Transmission Owners' ("NETOs"). In its Opinion, the FERC expressed concerns regarding anomalous market conditions during the record in that case. The FERC also distinguished the risks faced by investors in transmission companies from state regulated distribution companies. Based on the record in that case, the FERC finally decided upon a ROE for the NETOs that was above the midpoint of the two-stage DCF ROE result. In my opinion, the concerns regarding anomalous market conditions and the risks for investors in transmission companies that FERC described are not relevant considerations for setting an allowed return on equity for PSCO in this proceeding.[3]

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2 Opinion No. 414-A, 84 FERC at 61,423-24.

3 See Paragraphs 149 through 152 of Opinion No. 531.

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
3/83	1780	NM	New Mexico Public Service Commission	Boles Water Co.	Rate design, rate of return.
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design.
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

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As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc.	PGE Industrial Intervenors	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Comm.	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HealthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112		AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661		Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01		Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103		Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797		Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Elec. Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR		Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Gp.	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065		The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532		The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI		South Florida Hospital and Health Care Assn.	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana PSC	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Gp. Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation
03/10	09-1352-E-42T	WV	West Virginia Energy Users Gp.	Monongahela Power, Potomac Edison	Return on equity, rate of return
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design

Expert Testimony Appearances
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As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Compay	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Gp.	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Svc. Of Colorado	Return on equity, wtd. cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Assn.	Florida Power and Light Co,	Return on equity, wtd. cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pannsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

**Expert Testimony Appearances
of
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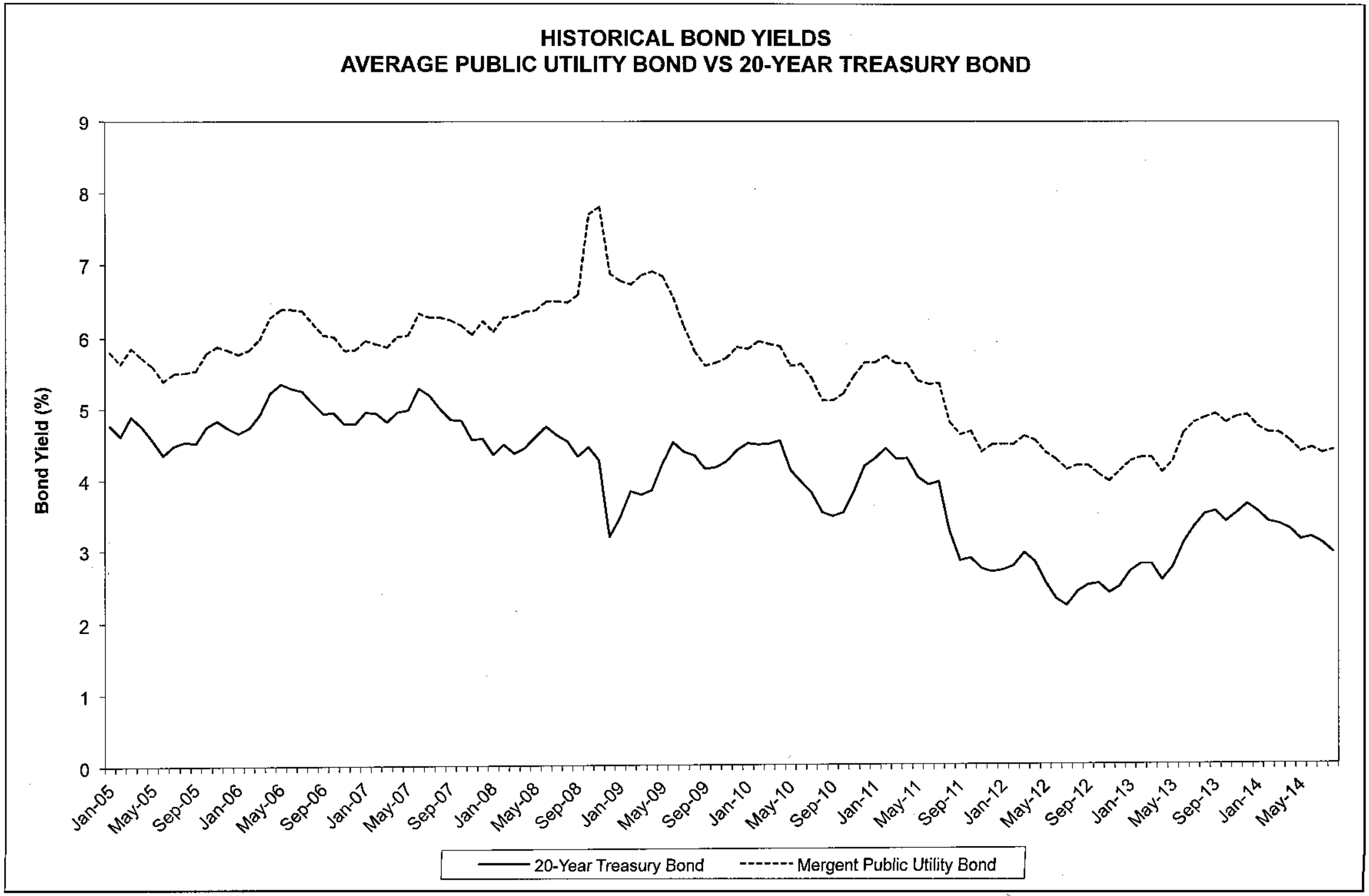
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Gp.	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital


HISTORICAL BOND YIELDS
AVERAGE PUBLIC UTILITY BOND VS 20-YEAR TREASURY BOND
Bond Yield (%)
9
8
7
6
5
4
3
2
1
0
Jan-05
May-05
Sep-05
Jan-06
May-06
Sep-06
Jan-07
May-07
Sep-07
Jan-08
May-08
Sep-08
Jan-09
May-09
Sep-09
Jan-10
May-10
Sep-10
Jan-11
May-11
Sep-11
Jan-12
May-12
Sep-12
Jan-13
May-13
Sep-13
Jan-14
May-14
20-Year Treasury Bond
Mergent Public Utility Bond

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	May-14
ALLETE	High Price ($)	52.680	48.820	48.800	51.560	51.470	51.820
	Low Price ($)	44.190	44.390	46.140	46.900	47.510	48.020
	Avg. Price ($)	48.435	46.605	47.470	49.230	49.490	49.920
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	4.05%	4.21%	4.13%	3.98%	3.96%	3.93%
	6 mos. Avg.	4.04%					
Alliant	High Price ($)	62.300	59.360	58.510	60.890	60.880	60.120
	Low Price ($)	55.380	54.690	55.040	56.500	56.550	56.090
	Avg. Price ($)	58.840	57.025	56.775	58.695	58.715	58.105
	Dividend ($)	0.510	0.510	0.510	0.510	0.510	0.510
	Mo. Avg. Div.	3.47%	3.58%	3.59%	3.48%	3.47%	3.51%
	6 mos. Avg.	3.52%					
Avista Corp.	High Price ($)	35.960	32.880	32.470	33.600	33.580	32.940
	Low Price ($)	30.550	30.450	30.350	31.020	30.380	30.900
	Avg. Price ($)	33.255	31.665	31.410	32.310	31.980	31.920
	Dividend ($)	0.318	0.318	0.318	0.318	0.318	0.318
	Mo. Avg. Div.	3.82%	4.02%	4.05%	3.94%	3.98%	3.98%
	6 mos. Avg.	3.97%					
Black Hills Corp.	High Price ($)	55.110	54.050	53.890	62.130	61.410	60.380
	Low Price ($)	47.110	47.870	50.390	52.700	57.020	55.230
	Avg. Price ($)	51.110	50.960	52.140	57.415	59.215	57.805
	Dividend ($)	0.390	0.390	0.390	0.390	0.390	0.390
	Mo. Avg. Div.	3.05%	3.06%	2.99%	2.72%	2.63%	2.70%
	6 mos. Avg.	2.86%					
CMS Energy	High Price ($)	32.910	30.830	30.540	31.200	31.230	30.430
	Low Price ($)	29.590	29.150	27.900	28.870	28.970	28.700
	Avg. Price ($)	31.250	29.990	29.220	30.035	30.100	29.565
	Dividend ($)	0.270	0.270	0.270	0.270	0.270	0.270
	Mo. Avg. Div.	3.46%	3.60%	3.70%	3.60%	3.59%	3.65%
	6 mos. Avg.	3.60%					
Consolidated Edison	High Price ($)	64.000	58.120	57.900	57.850	57.840	58.370
	Low Price ($)	56.400	55.800	54.580	55.280	54.120	53.610
	Avg. Price ($)	60.200	56.960	56.240	56.565	55.980	55.990
	Dividend ($)	0.630	0.630	0.630	0.630	0.630	0.630
	Mo. Avg. Div.	4.19%	4.42%	4.48%	4.46%	4.50%	4.50%
	6 mos. Avg.	4.42%					

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	May-14
Dominion Resources	High Price ($)	72.240	71.330	70.380	71.620	71.700	73.000
	Low Price ($)	65.530	67.290	64.710	67.580	67.060	68.180
	Avg. Price ($)	68.885	69.310	67.545	69.600	69.380	70.590
	Dividend ($)	0.600	0.600	0.600	0.600	0.600	0.600
	Mo. Avg. Div.	3.48%	3.46%	3.55%	3.45%	3.46%	3.40%
	6 mos. Avg.	3.47%					
Duke Energy	High Price ($)	82.680	75.210	74.000	74.480	74.390	74.780
	Low Price ($)	74.330	72.950	69.480	70.810	68.810	69.730
	Avg. Price ($)	78.505	74.080	71.740	72.645	71.600	72.255
	Dividend ($)	0.795	0.795	0.795	0.780	0.780	0.780
	Mo. Avg. Div.	4.05%	4.29%	4.43%	4.29%	4.36%	4.32%
	6 mos. Avg.	4.29%					
Edison International	High Price ($)	62.900	59.540	59.180	58.110	58.240	57.220
	Low Price ($)	55.880	54.120	54.320	54.720	53.780	53.630
	Avg. Price ($)	59.390	56.830	56.750	56.415	56.010	55.425
	Dividend ($)	0.355	0.355	0.355	0.355	0.355	0.355
	Mo. Avg. Div.	2.39%	2.50%	2.50%	2.52%	2.54%	2.56%
	6 mos. Avg.	2.50%					
Empire District	High Price ($)	29.240	25.950	26.000	25.870	25.710	24.420
	Low Price ($)	24.090	24.000	24.020	24.360	23.560	23.230
	Avg. Price ($)	26.665	24.975	25.010	25.115	24.635	23.825
	Dividend ($)	0.255	0.255	0.255	0.255	0.255	0.255
	Mo. Avg. Div.	3.83%	4.08%	4.08%	4.06%	4.14%	4.28%
	6 mos. Avg.	4.08%					
IDACORP	High Price ($)	64.120	56.970	56.800	58.790	57.860	56.370
	Low Price ($)	53.390	53.200	51.700	53.550	53.780	52.910
	Avg. Price ($)	58.755	55.085	54.250	56.170	55.820	54.640
	Dividend ($)	0.430	0.430	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	2.93%	3.12%	3.17%	3.06%	3.08%	3.15%
	6 mos. Avg.	3.09%					
NextEra Energy	High Price ($)	100.510	98.520	98.630	102.460	102.510	100.350
	Low Price ($)	90.330	92.570	91.790	93.800	94.190	94.220
	Avg. Price ($)	95.420	95.545	95.210	98.130	98.350	97.285
	Dividend ($)	0.725	0.725	0.725	0.725	0.725	0.725
	Mo. Avg. Div.	3.04%	3.04%	3.05%	2.96%	2.95%	2.98%
	6 mos. Avg.	3.00%					

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	May-14
Northeast Utilities	High Price ($)	49.980	46.570	45.900	47.370	47.370	47.510
	Low Price ($)	44.370	43.880	41.920	43.780	44.280	44.770
	Avg. Price ($)	47.175	45.225	43.910	45.575	45.825	46.140
	Dividend ($)	0.393	0.393	0.393	0.393	0.393	0.393
	Mo. Avg. Div.	3.33%	3.48%	3.58%	3.45%	3.43%	3.41%
	6 mos. Avg.	3.45%					
Pinnacle West	High Price ($)	61.560	57.740	56.970	57.950	58.060	57.090
	Low Price ($)	54.590	54.130	52.130	53.290	53.040	53.810
	Avg. Price ($)	58.075	55.935	54.550	55.620	55.550	55.450
	Dividend ($)	0.595	0.568	0.568	0.568	0.568	0.568
	Mo. Avg. Div.	4.10%	4.06%	4.16%	4.08%	4.09%	4.10%
	6 mos. Avg.	4.10%					
Portland General Electric	High Price ($)	36.860	34.550	34.470	34.740	34.690	33.570
	Low Price ($)	32.070	31.700	31.410	31.930	32.150	32.460
	Avg. Price ($)	34.465	33.125	32.940	33.335	33.420	33.015
	Dividend ($)	0.280	0.280	0.280	0.280	0.280	0.275
	Mo. Avg. Div.	3.25%	3.38%	3.40%	3.36%	3.35%	3.33%
	6 mos. Avg.	3.35%					
Southern Company	High Price ($)	47.690	44.820	44.400	45.470	45.580	45.450
	Low Price ($)	43.550	43.040	41.870	43.220	42.780	42.550
	Avg. Price ($)	45.620	43.930	43.135	44.345	44.180	44.000
	Dividend ($)	0.525	0.525	0.525	0.525	0.525	0.525
	Mo. Avg. Div.	4.60%	4.78%	4.87%	4.74%	4.75%	4.77%
	6 mos. Avg.	4.75%					
Westar Energy	High Price ($)	37.910	37.070	37.090	38.230	38.240	36.100
	Low Price ($)	33.730	33.760	34.530	36.040	35.220	34.720
	Avg. Price ($)	35.820	35.415	35.810	37.135	36.730	35.410
	Dividend ($)	0.350	0.350	0.350	0.350	0.350	0.350
	Mo. Avg. Div.	3.91%	3.95%	3.91%	3.77%	3.81%	3.95%
	6 mos. Avg.	3.88%					
Xcel Energy	High Price ($)	33.760	32.480	32.060	32.260	32.290	32.370
	Low Price ($)	30.180	30.120	29.600	30.730	30.050	29.830
	Avg. Price ($)	31.970	31.300	30.830	31.495	31.170	31.100
	Dividend ($)	0.300	0.300	0.300	0.300	0.300	0.300
	Mo. Avg. Div.	3.75%	3.83%	3.89%	3.81%	3.85%	3.86%
	6 mos. Avg.	3.83%					
Average Dividend Yield		3.68%					

Source: Yahoo! Finance

COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
ALLETE, Inc.	4.00%	6.00%	3.50%	6.00%	6.00%
Alliant Energy Corporation	4.50%	6.00%	5.00%	4.80%	4.70%
Avista Corporation	4.50%	5.50%	3.00%	5.00%	5.00%
Black Hills Corporation	4.00%	9.50%	4.00%	7.00%	7.00%
CMS Energy Corporation	6.00%	6.50%	6.00%	6.10%	6.80%
Consolidated Edison, Inc.	2.00%	2.00%	3.00%	2.80%	2.72%
Dominion Resources, Inc.	5.00%	5.50%	4.00%	5.50%	6.17%
Duke Energy Corporation	2.00%	5.00%	3.00%	4.70%	4.70%
Edison International	7.50%	2.50%	6.00%	3.60%	3.49%
Empire District Electric Co.	4.50%	4.00%	3.50%	3.00%	3.00%
IDACORP, Inc.	8.00%	1.50%	3.50%	4.00%	4.00%
Nextera Energy	8.50%	6.00%	5.00%	6.60%	6.48%
Northeast Utilities	7.50%	8.00%	4.00%	6.50%	6.31%
Pinnacle West Capital Corp.	3.00%	4.00%	3.50%	3.70%	3.75%
Portland General Electric Company	4.50%	5.00%	4.00%	7.80%	7.80%
Southern Company	3.50%	3.50%	3.50%	3.50%	3.35%
Westar Energy, Inc.	3.00%	6.00%	4.50%	3.80%	2.40%
Xcel Energy Inc.	5.00%	5.50%	4.00%	4.20%	4.49%
Averages	4.83%	5.11%	4.06%	4.92%	4.90%
Median Values	4.50%	5.50%	4.00%	4.75%	4.70%

Sources: Value Line Investment Survey, August 22,September 19, and October 31, 2014
Yahoo! Finance for IBES growth rates retrieved October 15, 2014
Zacks growth rates retrieved October 15, 2014
IBES growth rates were used in the Zacks column for ALLETE, Avista, and Black Hills.

COMPARISON GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.68%	3.68%	3.68%	3.68%	3.68%
Average Growth Rate	4.83%	5.11%	4.92%	4.90%	4.94%
Expected Div. Yield	3.77%	3.77%	3.77%	3.77%	3.77%
DCF Return on Equity	***8.60%***	***8.88%***	***8.69%***	***8.67%***	***8.71%***
Method 2:					
Dividend Yield	3.68%	3.68%	3.68%	3.68%	3.68%
Median Growth Rate	4.50%	5.50%	4.75%	4.70%	4.86%
Expected Div. Yield	3.76%	3.78%	3.76%	3.76%	3.77%
DCF Return on Equity	***8.26%***	***9.28%***	***8.51%***	***8.46%***	***8.63%***

COMPARISON GROUP
DCF RETURN ON EQUITY WITH FERC TWO-STAGE GROWTH

(1)	(2) Dividend Yield	(3) Adjustment	(4) Expected Div. Yield	(5) IBES Growth	(6) GDP Growth	(7) FERC Weighted Growth	(8) ROE
ALLETE, Inc.	4.04%	1.027	4.15%	6.00%	4.36%	5.45%	9.61%
Alliant Energy Corporation	3.52%	1.023	3.60%	4.70%	4.36%	4.59%	8.18%
Avista Corporation	3.97%	1.024	4.06%	5.00%	4.36%	4.79%	8.85%
Black Hills Corporation	2.86%	1.031	2.95%	7.00%	4.36%	6.12%	9.07%
CMS Energy Corporation	3.60%	1.030	3.71%	6.80%	4.36%	5.99%	9.69%
Consolidated Edison, Inc.	4.42%	1.016	4.50%	2.72%	4.36%	3.27%	7.76%
Dominion Resources, Inc.	3.47%	1.028	3.56%	6.17%	4.36%	5.57%	9.13%
Duke Energy Corporation	4.29%	1.023	4.39%	4.70%	4.36%	4.59%	8.98%
Edison International	2.50%	1.019	2.55%	3.49%	4.36%	3.78%	6.33%
Empire District Electric Co.	4.08%	1.017	4.15%	3.00%	4.36%	3.45%	7.60%
IDACORP, Inc.	3.09%	1.021	3.15%	4.00%	4.36%	4.12%	7.27%
Nextera Energy	3.00%	1.029	3.09%	6.48%	4.36%	5.77%	8.86%
Northeast Utilities	3.45%	1.028	3.54%	6.31%	4.36%	5.66%	9.20%
Pinnacle West Capital Corp.	4.10%	1.020	4.18%	3.75%	4.36%	3.95%	8.14%
Portland General Electric	3.35%	1.033	3.46%	7.80%	4.36%	6.65%	10.11%
Southern Company	4.75%	1.018	4.84%	3.35%	4.36%	3.69%	8.53%
Westar Energy, Inc.	3.88%	1.015	3.94%	2.40%	4.36%	3.05%	7.00%
Xcel Energy Inc.	3.83%	1.022	3.92%	4.49%	4.36%	4.45%	8.37%
Averages	3.68%		3.76%	4.90%	4.36%	4.72%	8.48%
Median							8.69%

FERC GDP GROWTH RATE

	2020	2040	2044	2070	
IHS Global Insight					4.30%
Energy Information Administration					
Real GDP	16,753	26,670			
GDP Deflator	1.307	1.913			
	21,896	51,020			4.32%
SSA Trustees Report	23,694			211,004	4.47%
Average GDP Growth Rate					4.36%

Sources:
Direct Testimony of Richard Baudino, Exhibit LC-10, FERC Docket Nos. ER13-1508-001 et al., Oct. 9, 2014
IHS Global Insight growth rate from Exhibit ESI-104, page 2 of 2, FERC Docket Nos. ER13-1508-001 et al.
Energy Information Administration, *Annual Energy Outlook 2014* (May 7, 2014).
Social Security Administration, 2014 OASDI Trustees Report,
Table VI.G6 - Selected Economic Variables, Calendar Years 2013-90

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.98%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	3.09%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.88%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.49%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.58%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.98%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.68%
4	Risk Premium	
5	(Line 1 minus Line 3)	10.30%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.52%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.20%

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
April-14	3.27%
May-14	3.12%
June-14	3.15%
July-14	3.07%
August-14	2.94%
September-14	3.01%
6 month average	3.09%

5 Year Treasury Bond Data

	Avg. Yield
April-14	1.70%
May-14	1.59%
June-14	1.68%
July-14	1.70%
August-14	1.63%
September-14	1.77%
6 month average	1.68%

Source: www.federalreserve.gov, Selected Interest Rates (Dalily) - H.15

Value Line Market Growth Rate Data:

Forecasted Data:	
Value Line Average Growth Rates:	
Earnings	14.37%
Book Value	9.83%
Average	12.10%
Average Dividend Yield	0.78%
Estimated Market Return	12.88%
Value Line Median Growth Rates:	
Earnings	12.00%
Book Value	8.75%
Average	10.38%
Median Dividend Yield	0.78%
Estimated Market Return	11.16%
Value Line Projected 3-5 Yr. Annual Total Return	11.89%
Average of Projected Mkt. Returns	11.98%

Source: Value Line Investment Survey for Windows retreived October 15, 2014

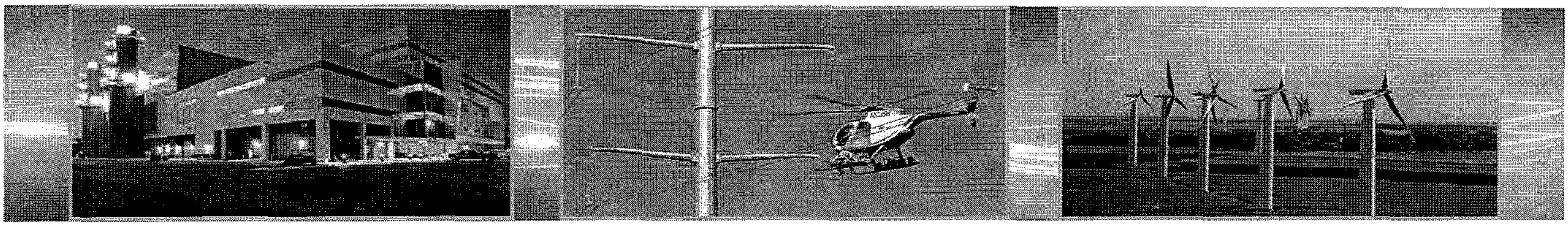
Comparison Group Betas:	Value Line
ALLETE, Inc.	0.80
Alliant Energy Corporation	0.80
Avista Corporation	0.80
Black Hills Corporation	0.90
CMS Energy Corporation	0.75
Consolidated Edison, Inc.	0.60
Dominion Resources, Inc.	0.70
Duke Energy Corporation	0.60
Edison International	0.75
Empire District Electric Co.	0.65
IDACORP, Inc.	0.80
Nextera Energy	0.70
Northeast Utilities	0.75
Pinnacle West Capital Corp.	0.70
Portland General Electric	0.80
Southern Company	0.60
Westar Energy, Inc.	0.75
Xcel Energy Inc.	0.70
Average	0.73

Source: Value Line Investment Survey

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%
Long-Term Annual Income Return on Long-Term Government Bonds	5.30%	5.30%
Historical Market Risk Premium	4.80%	6.80%
Comparison Group Beta, Value Line	0.73	0.73
Beta * Market Premium	3.51%	4.97%
Current 20-Year Treasury Bond Yield	3.09%	3.09%
CAPM Cost of Equity, Value Line Beta	**6.60%**	**8.06%**

Source: *Ibbotson SBBI 2014 Classic Yearbook,* Morningstar, pp. 39 - 40.

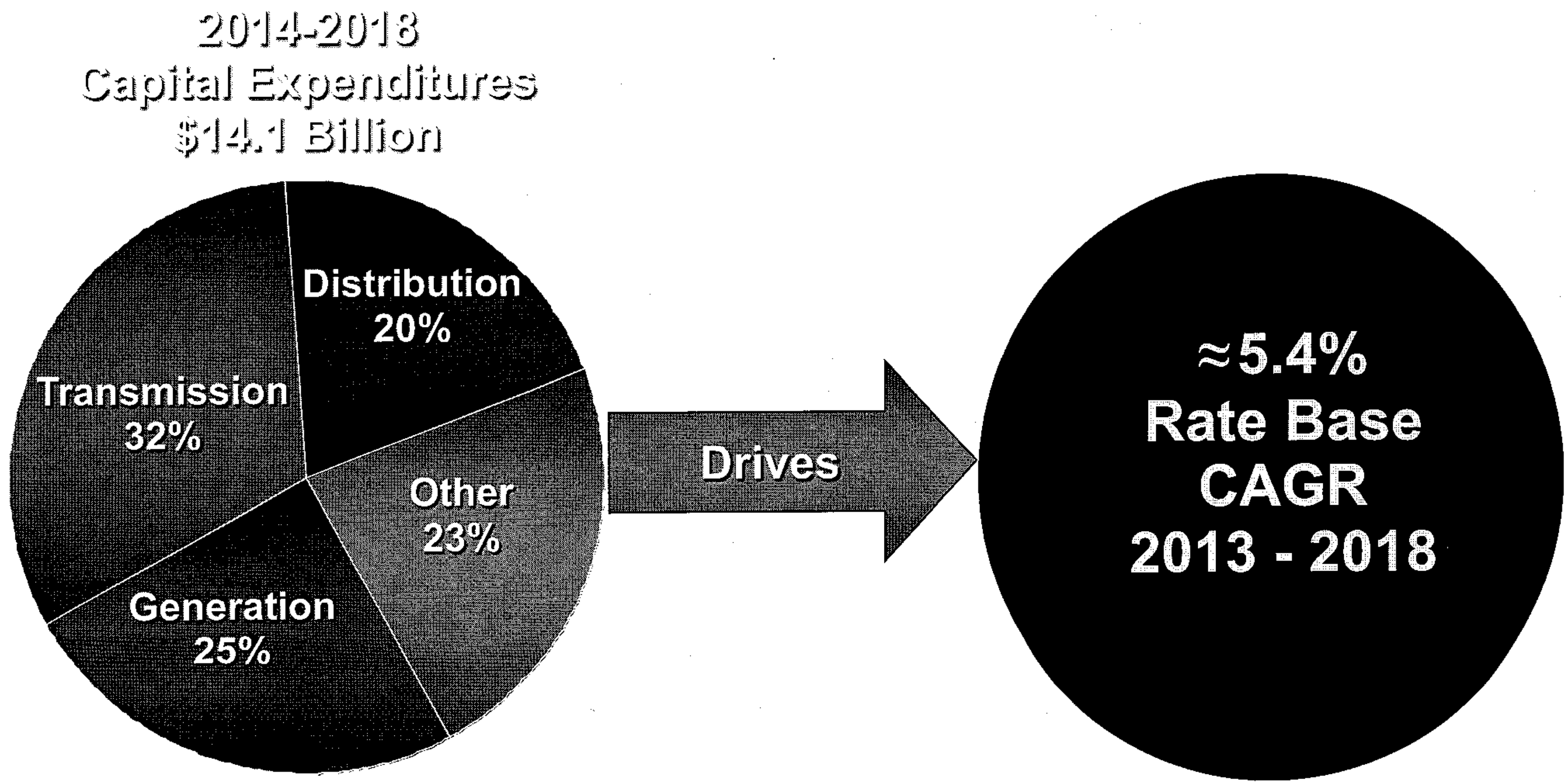


Well Positioned for the Future

Wolfe Research
2014 Power & Gas Leaders Conference
September 17, 2014

* Based off a normalized 2013 EPS of $1.90

Low Risk Investment Plan Drives Attractive Rate Base Growth



Jurisdiction	Status	Rate Plan	Percent of Rate Base
Minnesota Electric	Pending	Multi-Year Plan (2014-15)	≈ 35%
Colorado Electric	Pending	Multi-Year Plan (2015-17)	≈ 31%
North Dakota Electric	Approved	Multi-Year Plan (2013-16)	≈ 2%

Bending the Cost Curve

- Sustainable Cost Control
  - Standardization of processes
  - Optimize purchasing power
  - Technology
- Stabilization of nuclear costs
- Workforce transition
- Proactive maintenance
- Employee benefits programs
- Investing in capital to reduce O&M

Projected

Annual O&M Growth

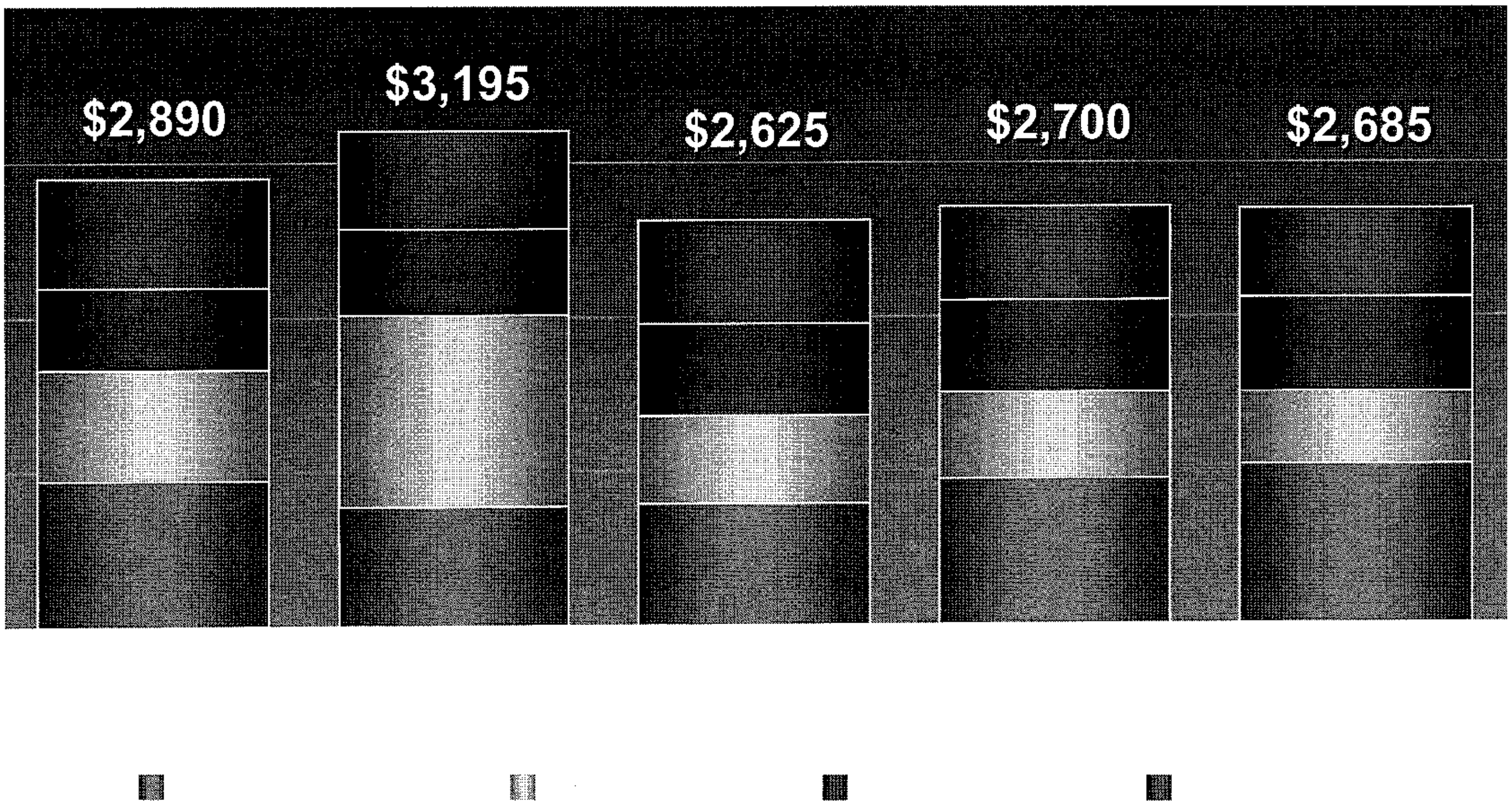
2014: 2% - 3%

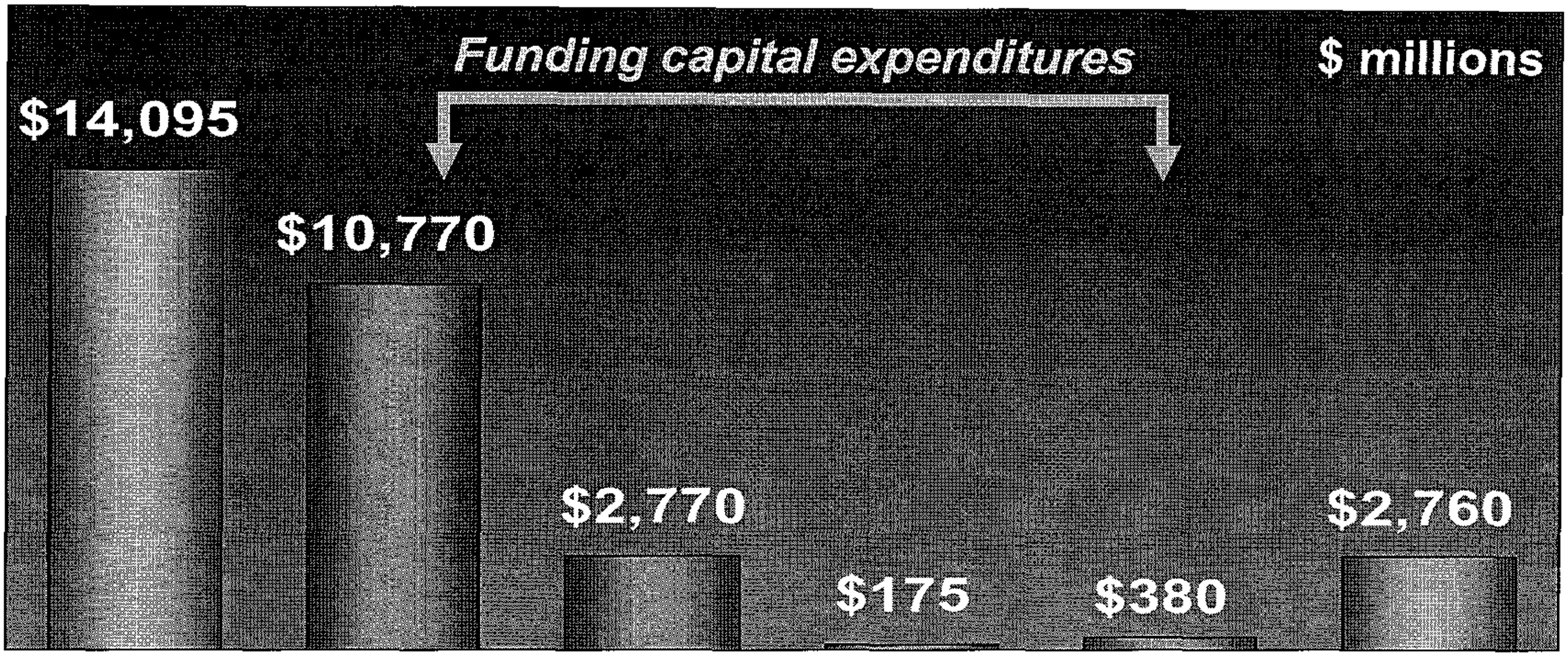
2015-18: 0% - 2%

Low Risk Capital Investment Plan

Five-Year Total of $14.1 Billion

Dollars in millions





* Cash from operations is net of dividend and pension funding
** The $175 million of equity was issued in the first half of 2014
** No further equity (beyond DRIP & benefit programs) is expected to be issued through 2018, based on current capital forecast
(Financing plans are subject to change)

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, to Conduct a Biennial Review of Costs and Rates - Test Year 2015 Rates

Docket No. 05-UR-107

DIRECT TESTIMONY OF RICHARD A. BAUDINO

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. I have testified in proceedings before the Public Service Commission of Wisconsin (the "Commission") on several previous occasions. Please refer to Ex.-WIEG-Baudino-1 for my expert testimony experience.

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

A. I am testifying on behalf of the Wisconsin Industrial Energy Group, Inc. ("WIEG"), an association of large industrial and manufacturing businesses, many of which are customers of Wisconsin Electric Power Company ("WEPCO" or the "Company").

Q. What is the purpose of your testimony in this proceeding?

A. I am responding to the Direct Testimony of WEPCO witness Eric Rogers on a number of issues associated with the Company's filed electric class cost of service studies ("CCOSS"), the apportionment of the approved revenue increase among rate schedules, and rate design.

Q. Would you summarize your positions and recommendations in this proceeding?

A. Yes.

- As I testified in WEPCO's last base rate case (Docket No. 05-UR-106), I recommend that the Commission approve a CCOSS that classifies 100% of WEPCO's production costs as demand-related and allocates those costs to customer classes using the 4 CP peak responsibility method. Mr. Rogers agrees with the use of a 4CP allocator, as he did in WEPCO's last base rate case. He also classifies more production costs (75%) as demand-related than he did in 05-UR-106 (60%). This modification is a definite improvement over WEPCO's past CCOSS. However, I maintain that 100% of production costs be classified as demand-related.

- I recommend that the Commission adopt an allocation of energy costs based on Locational Marginal Pricing ("LMP"), which is an appropriate and reasonable proxy for the E8760 allocation method I recommended in WEPCO's last base rate case.

- In light of the results from Mr. Rogers' base-case CCOSS and alternate CCOSS, presented in Ex.-WEPCO/WG-Rogers-12r, Schedules 18A and 18B (PSC REF#: 210296), and my own, I recommend that the Commission keep rates flat for the Large customer classes, before accounting for the biomass credit or fuel deferral. I also recommend that the Commission require that WEPCO include in its next base rate case the embedded costs of generation, transmission, and distribution, which information will provide valuable, additional guidance for rate design.

- I recommend that the Commission order WEPCO to file seasonally differentiated energy rates in it next base rate case because WEPCO's energy costs are higher in the summer than in the non-summer months.

- I recommend that the Commission increase to $6.38/kW the Company's interruptible capacity credit for rate schedule CpFN.

II. DISCUSSION OF CLASS COST OF SERVICE ISSUES

Q. Before you address the Company's testimony, please provide a general description of the process of allocating cost responsibility to customer classes using a cost of service study.

A. A class cost of service study allocates and assigns the total cost of providing utility service to the various classes of customers receiving that service. In certain instances, a utility can identify and directly assign cost to customers. For most costs, however, direct assignments are not possible and a cost of service study is used to determine which customers are responsible for which utility costs.

The development of a class cost of service study consists of three steps: functionalization, classification, and allocation. Step 1, functionalization, involves separating the utility's investment and expenses into major functional categories. For integrated electric utilities like WEPCO, these categories include production, transmission, and distribution. The FERC Uniform System of Accounts provides the method by which costs are identified and segregated into these various functional categories. To my knowledge, the Company, Commission Staff, and Intervenors have no disagreements as to functionalization.

Step 2 is classification. Once functionalization is complete, a utility's costs are classified as demand-related, energy-related, and customer-related. Demand-related costs are those that are based on the utility's customers' demand, and they are fixed in the short term. Production and transmission costs and a portion of the distribution system investment in poles, wires, etc. are considered demand-related. Energy-related costs are those that vary with customers' energy (kWh) consumption and include fuel costs and variable purchased power costs. Customer-related costs are those that are associated with the number of customers and include items such as meters and services. It is also appropriate to classify as customer-related a portion of the distribution investment in FERC Accounts 364 through 370. Classification of certain costs—production plant, for instance—are frequently in issue, as they are in this case. For example, should production plant be classified as 100% demand, or some combination of demand and energy?

Step 3 is allocation. After costs are classified as demand-, energy-, or customer-related, they are allocated to customer classes in proportion to each class's contribution to the respective cost classifications. Generally speaking, demand-related costs are allocated to customer classes in proportion to each class's contribution to the system peak demand and/or non-coincident peak demands; energy-related costs are allocated to customer classes in proportion to each class's kWh consumption (energy usage); customer-related costs are allocated based on the number of customers or on weighted customer allocation factors. Allocation of certain costs—demand-related production plant, for instance—also are frequently in issue. For example, should demand-related production plant costs be allocated using 4CP, 12CP or some other method?

Q. Why is a class cost of service study important in the ratemaking process?

A. A properly performed class cost of service study assigns the utility's total cost to serve its customers to the customer classes that receive that service. From this information the regulatory commission may then determine whether each customer class is paying its fair share of costs and it can then allocate any revenue increase (or decrease) accordingly. For example, if the regulatory commission has as an overarching goal the fair treatment of all utility customers, then it can use CCOSS results to determine if a customer class is paying less than its share of costs and then reasonably conclude that that class should receive a percentage increase greater than the overall system increase in order to provide greater rate equity. Likewise, it can reasonably conclude that a customer class that is paying more than its fair share of costs—subsidizing other customer classes—should receive a lower-than-average percentage increases. In certain cases, it may be appropriate for such a class of customers to receive no increase or even a decrease in rates if that class is paying rates greatly in excess of the utility's cost to serve those customers.

Q. Would you please briefly describe the CCOSS methodology WEPCO used in this case?

A. I describe WEPCO's CCOSS methodologies (base-case and alternate) only as relates to two areas in which I continue to have disagreements with WEPCO's approach (the fact that I am addressing only two areas of WEPCO's approach is not an indication that I agree with all of WEPCO's approach, save these two areas—these two are simply the ones I am addressing in this proceeding). The first relates to the classification of production plant, and the allocation to customer classes of both the demand-related and energy-related portions of those costs; the second relates to the allocation to customer classes of energy-related fuel and purchased power costs.

<u>WEPCO's Classification of Production Plant Costs</u>

WEPCO witness Eric Rogers discusses the Company's approach to the allocation of production plant costs beginning on Direct-WEPCO/WG-Rogers-11 of his Direct Testimony. Mr. Rogers testifies that the Company's CCOSS classifies production plant costs as 75% demand-related and 25% energy-related, which is a departure from the Company's recent past use of an equivalent peaker methodology ("EP") to classify demand and energy production plant costs. Mr. Rogers also testifies that the CCOSS allocates to customer classes the demand-related portion of production plant (75% of costs) in proportion to each class's contribution to WEPCO's coincident peaks in the four summer months (which are the four months with WEPCO's highest system peaks), also known as the 4CP method. The energy-related portion of production plant costs (25% of costs) is allocated to customer classes with an LMP-weighted energy allocator. This weighted energy allocator aggregates hourly forecasted LMPs for 2015 and 2016 into the monthly and day-type load profiles derived for the average daily load curves provided by the Company in response to PSCW-RATES-7.

<u>WEPCO's Allocation of Energy-related Fuel and Purchased Power Costs.</u>

On Direct-WEPCO/WG-Rogers-13, Mr. Rogers states that the Company's "base-case cost-of-service" uses unweighted energy values in the allocation of energy-related fuel and purchased power costs. Mr. Rogers also presents the results of an "alternate" CCOSS that allocates these costs in the same way the Company allocates the 25% of production plant classified as energy-related using LMP-weighted energy values to allocate total, on-peak and off-peak fuel and purchased power costs.

Q. Mr. Baudino, please comment on Mr. Rogers' presentation and approach to cost allocation studies in the proceeding.

A. Mr. Rogers made an important modification in his classification of production plant, increasing that portion classified as demand-related from 60% (in 05-UR-106) to 75% (in this case). This is a meaningful change that I believe is in the correct direction. Still, I maintain (as WIEG has long advocated) that 100% of production plant should be classified as demand-related. Mr. Rogers and I do agree that the portion of production plant classified as demand-related should be allocated to classes using 4CP.

Q. Please explain why production plant should not be classified as energy-related.

A. All production plant costs should be classified as demand-related and allocated to customer classes on the basis of class contribution to system peak demand or, in this case, 4CP. This recognizes the fact that all production plant must be available and on line to meet the peak demand requirements of WEPCO's customers. Excess capacity exists during off-peak periods, indicating that off-peak loads and consumption do not contribute to the need for full production capacity throughout the year. Allocating production plant on the basis of class contribution to system peak demands more closely aligns cost responsibility with how costs are incurred by the system.

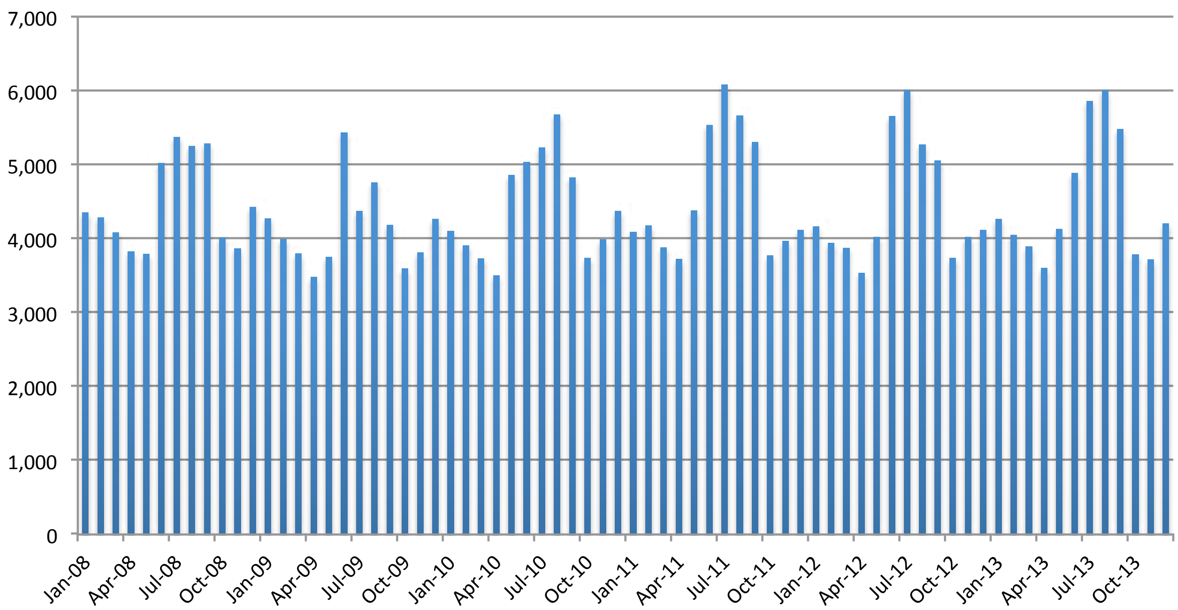
Further, because the EP methodology assigns such a large percentage of production plant on the basis of customer energy use, it discourages the improvement of customer load factors and the use of existing base load and intermediate load plant. In other words, WEPCO's customers get a price signal that says additional off-peak energy usage imposes a cost on the Company that is greater than actual off-peak energy costs. This occurs because each additional kWh of off-peak usage results in additional base load fixed costs (return, depreciation, fixed O&M expenses) being assigned to the rate class. This results in an inefficient use of resources (existing base load plant would be underutilized) because the effective rate charged to customers would be substantially above marginal off-peak energy costs.

Finally, under an energy-based approach to the classification of production costs, high load factor customers, particularly the larger commercial and industrial customers, are penalized for their more even and efficient use of energy throughout the year. As they move more loads to off-peak periods, they incur significantly higher charges than they should. Similarly, all customers have less incentive to reduce their peak demand because their demand charges are lower than the costs peak system usage imposes on the Company. This can discourage the development of load-flattening innovations.

Q. Is the 4CP method to allocate production plant supported by the profile of WEPCO's monthly system peaks?

A. Yes, most definitely. Figure 1 below presents a six-year history of WEPCO's monthly peaks that was provided by the Company in its response to 1-WIEG-8. WEPCO is clearly and consistently a summer peaking utility during the months of June through September. The 4CP method captures this relationship and appropriately allocates cost to customers based on how WEPCO's customers actually use the system.

Figure 1
WEPCO Monthly System Peaks (mws)
2008 - 2013



On average over the last six years, WEPCO's four summer months' peak demands are 33% higher than the peak demands for the non-summer months. Clearly, WEPCO's four-month summer peak is the dominant factor in cost causation for the Company.

Q. Earlier in your testimony, you stated that Mr. Rogers presented an alternate CCOSS that allocated fuel and purchased power costs using LMP. Would it be appropriate to refine the Company's on-peak/off-peak fuel and purchased power methodology by utilizing the LMP to allocate fuel and energy-related purchased power costs to customer classes in the CCOSS?

A. Yes. This methodology, which approximates the E8760 methodology I advocated in 05-UR-106, allocates fuel and purchased energy cost by recognizing rate class cost responsibility on an hourly basis, which more accurately allocates these costs than does the unweighted energy values Mr. Rogers uses in his base-case CCOSS . This approach provides a more precise allocation of energy costs to WEPCO's customers. The LMP-weighted energy allocator that Mr. Rogers uses is similar enough in approach to the E8760 method that I can recommend its use in this proceeding. Both methods rely on hourly energy throughout the year to allocate costs to customer classes. And both methods are superior to simply allocating energy costs using unweighted energy values as was done in WEPCO's base-case CCOSS.

Further, in both WEPCO's base-case CCOSS and its alternate CCOSS, Mr. Rogers uses the LMP method to allocate the portion of production plant costs that he classified as energy-related. The allocation of fuel and energy-related purchased power costs should use this same LMP method.

Q. Does the use of LMP make a difference in customer class cost responsibility?

A. Yes, it makes a significant difference. According to Schedules 18A and 18B, line 21, of Ex.-WEPCO/WG-Rogers-12r, the Large customer class should receive a cost-based revenue reduction (a -0.1% increase) under WEPCO's alternate CCOSS in contrast to a 0.7% increase under the Company's base-case CCOSS. In not using the more accurate

LMP method to allocate all these energy-related costs in its base-case CCOSS, Large customer class cost responsibility is overstated by nearly a full percentage point.

Q. Which approach to classifying and allocating production plant do you recommend the Commission adopt in this proceeding?

A. As I did in Docket No. 05-UR-106, I recommend that the Commission adopt the 100% Demand, 4CP method. WEPCO is a strongly summer peaking system and the 4CP allocation method tracks the Company's load profile and allocates costs to WEPCO's customer classes accordingly.

Q. Did you prepare a CCOSS using the 4CP allocation method for production costs?

A. Yes. Ex.-WIEG-Baudino-2 presents summary pages for my 4CP CCOSS. I developed this CCOSS using the Company's alternate CCOSS that WEPCO provided in discovery—a single change was necessary. The WEPCO alternate CCOSS classified only 75% of production plant costs as demand-related; my WIEG 4CP instead classifies 100% of production costs as demand-related. In all ways but this, the WEPCO alternate CCOSS and my WIEG 4CP CCOSS are identical. Table 1 below presents summary results of **(1) WEPCO's base case CCOSS**; (2) its **alternate CCOSS** (which includes a single change from the base case—the allocation of energy-related fuel and purchased power costs using hourly LMPs (*see* Direct-WEPCO/WG-Rogers-13)); and (3) my recommended **WIEG 4CP CCOSS** which makes a single change from the WEPCO alternate—the classification of 100% of production plant as demand-related. Note that the CCOSS results of Table 1 are at the WEPCO's requested 2.7% revenue requirement increase and do not include the biomass credit and fuel deferral. Should WEPCO's requested revenue requirement materially change, it could be necessary to review the CCOSS results anew.

TABLE 1

CLASS COST OF SERVICE RESULTS

	WIEG 4CP	WEPCO Base Case	WEPCO Alternate
Small	7.7%	6.2%	6.9%
Medium	-6.7%	-6.4%	-6.5%
Large	-0.9%	0.7%	-0.1%
Streelighting	-31.1%	-24.1%	-26.3%
Total	2.7%	2.7%	2.7%

Note that the three CCOSS results for the Large customer classes range from a much-less-than-system average increase of just 0.7% to a decrease of nearly 1%.

Q Do you have any other CCOSS-related issues to address?

A. I am still reviewing the allocation of distribution costs to determine how, if at all, they are allocated to transmission-level customers. I may file supplemental direct testimony as a result of this review.

Q. What is your recommendation for the allocation of revenues in this case?

A. Based on WEPCO's two CCOSS, and my WIEG 4CP CCOSS, a decrease for the large customers is fully justified. However, with certain customer classes well over the system-wide average, the Commission could well keep rates unchanged for those customer groups who could see a decrease in order to mitigate a rate increase for other customer classes (small). Thus, I recommend that the Commission not change large customer class base rates at all for 2015 and 2016. Should WEPCO's requested revenue requirement increase change materially (either up or down), I will revisit this question.

III. RATE DESIGN ISSUES

Q. Would you please briefly summarize the rate design issues that you will address in your testimony?

A. Yes. For purposes of this case, I generally do not object to the Company's rate design proposals for Large customer rate schedules, although I believe that it is better to base rates on the classification and allocation of demand, energy and customer costs in the 100% 4CP CCOSS.

On Direct-WEPCO/WG-Rogers-42, Mr. Rogers explained his approach to rate design for the Large customer classes. Essentially Mr. Rogers used marginal costs to set billing demand charges, which are presented in Ex.-WEPCO/WG-Rogers-11. Facilities charges are set to recover customer-related costs. Finally, on-peak and off-peak energy rates recover the remaining production, transmission, and distribution costs not recovered by the demand charges The energy rates are set proportional to the on-peak and off-peak energy costs presented in Ex.-WEPCO/WG-Rogers-11.

Q. Do you agree with on-peak and off-peak rates for the Large customer classes being set as "fallout" rates that collect the revenue requirement not collected by the demand and customer charges?

A. No. This approach overstates actual energy costs and results in a substantial amount of fixed embedded costs being collected in variable energy rates. The approach adversely affects high load factor customers, who use more energy per kW of demand than low load factor customers. Overstated energy rates and understated demand rates also send improper price signals to customers. Basically, such rates tell customers that energy consumption is more expensive than it really is and that the cost of capacity is lower than it really is. Over time, this could lead to reductions in energy consumption and a lower system load factor, increasing the "peakiness" of the system. At best, larger customers have reduced incentives for load flattening changes in their demand and consumption profiles.

Q. Do you have a recommendation regarding rate design for WEPCO's next base rate proceeding?

A. Yes. I recommend that WEPCO be required to present the embedded costs per kW of generation, transmission, and distribution in its next rate proceeding. Although WEPCO has traditionally relied on marginal costs for designing rates, marginal costs tend to understate embedded demand costs and overstate embedded energy costs. Using embedded costs as additional guidance in rate design would provide additional information on the actual costs of energy and capacity and would be useful additional guidance in the rate design process.

Q. Do you have an additional recommendation for WEPCO's energy rates?

A. Yes. I recommend that WEPCO file seasonally differentiated energy charges in its next base rate proceeding. Ex.-WEPCO/WG-Rogers-11, Schedule 2 shows that on-peak and off-peak marginal energy costs are higher in the summer months than in non-summer months. For the average of 2015 and 2015, summer on-peak and off-peak energy costs are $45.23/mWh and $27.79/mWh, respectively. Non-summer marginal energy costs are $34.73/mWh on-peak and $27.41/mWh off-peak. In my opinion, this is enough difference for WEPCO to further refine its rate design in the next case and present seasonally differentiated energy rates.

Q. How does the Company develop interruptible credits for rate CpFN?

A. The current interruptible capacity credit (the amount by which firm production demand charges are reduced) for rate CpFN is $5.36 per kW/month. This capacity credit is supposed to reflect the avoided cost of combustion turbine capacity and represents the capacity cost that would otherwise be incurred to serve interruptible load if it was firm. As discussed by Mr. Rogers, the Company is proposing to maintain in proposed rates the interruptible capacity credit at the current amount.

Q. Do you agree that the proper interruptible capacity credit should be maintained at $5.36 per kW in this case?

A. No.

Q. Has the Company provided an explanation for its proposal to maintain the interruptible credit at existing levels?

A. At Direct-WEPCO/WG-Rogers-43 through Direct-WEPCO/WG-Rogers-44, Mr. Rogers stated that the Company is not proposing an increase in the interruptible credit because, in part, the Company had argued in Dockets 05-UR-104 and 05-UR-106 that the market price of capacity was well below the marginal cost of generation capacity for a combustion turbine. Mr. Rogers also noted that the market for contingent capacity has developed in recent years and that the contingency reserve value can be applied to certain non-firm loads. Mr. Rogers provided calculations of the cost of a combustion turbine and the cost of purchased capacity in Ex.-WEPCO/WG-Rogers-11 Schedule 5. Based on this range, Mr.

Rogers concluded that, for purposes of rate stability, the Company proposed no change in the current level of non-firm credits.

Q. Do you agree with the Company's proposal on this issue?

A. No. At a minimum, the interruptible credits for rate schedule CpFN should be increased at the same percentage rate as the firm demand charges. This is clearly justified based on the Company's own analysis of a cost-based interruptible capacity credit. Furthermore, rate stability will be maintained by increasing the non-firm demand charge at the same percentage level as the firm demand charge.

WEPCO proposed a 13% increase in the CpFN firm demand charge. Increasing the current interruptible credit by this percentage results in a credit of $6.06, which is still lower than the capacity cost of a combustion turbine.

Q. Are you also recommending a corresponding increase in the curtailable credits associated with rate schedules Cg3 and Cp3?

A. Yes. I am recommending that these credits be increased by the same percentage that I am recommending for the interruptible capacity credits. This is appropriate since the curtailable credits are based on the same avoided peaking capacity methodology used for the interruptible credits.

Q. Please comment on the idea of using current purchased capacity costs as a proxy for non-firm demand credits.

A. "Current market conditions" should not be the basis for setting the interruptible credits in each case before the Commission. WEPCO determines its interruptible credit by recognizing that interruptible load is a substitute for the peaking capacity that the Company would need to construct or obtain via contract if its interruptible customers did not agree to shed load—essentially shut down their facilities at substantial cost and inconvenience—when the overall system demand threatened to exceed WEPCO's resources. At times of reduced market demand for capacity, such as the current situation in MISO, the Company does not reduce its installed cost of peaking capacity (*i.e.*, implement a mark-to-market adjustment on plant in service); rather, the Company continues to request recovery of its actual costs. This same principle should apply to interruptible load that has permitted the Company to avoid the cost of constructing more peaking capacity. There is no principled reason to treat interruptible load as "swing" capacity that is valued at the lesser of market or avoided construction cost with every new base rate case. Industrial interruptible customers do not simply elect to take interruptible service without planning for possible interruptions in their respective production processes. In many cases, in order to take interruptible service, customers make further investments that are evaluated on the expected level of interruptible credits.

Q. Do you have any comments with respect to WEPCO's proposed rates for customer-owned generation?

A. Yes. A WIEG member recently became aware that it might be affected by WEPCO's proposed tariffs for customer-owned generation. Because of this member's situation it was not clear at the time of filing my testimony how this customer would be affected by the proposed tariff. WIEG is continuing to evaluate the effect of the proposed tariffs on this member and I may file supplemental direct (or rebuttal) testimony once the effects have been more fully evaluated.

Q. Do you have any concluding comments with respect to WEPCO's Large customer rates?

A. Yes. For WIEG's energy intensive members, the cost of electricity is a major component of their cost of production. Because a large energy customer's energy costs may represent as much as 30 percent or more of its entire annual operating budget, the effect an increase in energy prices has on such a business is much greater to it, proportionally, than the same percentage increase is to a residential or small business customer for which energy is but one of many small annual costs.

WIEG members must compete in national and international markets and must remain cost competitive. Therefore, it is important that the rates they pay for electricity be reasonable and based on the cost to serve.

I am advised that WIEG members compete with other facilities located in the Midwest and Southeast regions of the United States. Table 2 below presents average 2013 industrial rates in cents per kWh for several regions of the United States and for Wisconsin from the U.S. Energy Information Administration. Wisconsin is included in the East North Central region of the U.S.

TABLE 2

2013 AVERAGE INDUSTRIAL ELECTRICITY PRICES (Cents / kWh)

United States (Average all states)	6.82
East North Central U.S.	6.57
West North Central U.S.	6.60
South Atlantic U.S.	6.48
Wisconsin	7.54

Source: U.S. Energy Information Administration

Table 2 shows that Wisconsin's average industrial rate is 10.6% higher than the national average and 14.8% higher than the East North Central region in which Wisconsin is included. Further, Mr. John Feit, witness for the Staff of the Commission, presented the following industrial rate comparison in his Surrebuttal Testimony in Docket No. 6630-CU-101, which was taken from PSC REF#: 187356 filed in that docket. The rates per kWh assume a 5 mW firm customer at 100% load factor.

TABLE 3

WISCONSIN INDUSTRIAL RATE COMPARISON

	Cents/kWh	Pct. Diff.
WPSC	7.053	
NSP	7.591	108%
WP&L	7.619	108%
WEPCO	8.46	120%

Tables 2 and 3 show a clear cost disadvantage to industrial customers in WEPCO's service area. WEPCO's industrial rates are the highest in Wisconsin by far. As measured in cents/kWh, they are 24% higher than the national average. Given this rate disparity, rate stability for WEPCO's Large customers is a vitally important consideration with respect to revenue allocation in this proceeding.

Q. Does that complete your Direct Testimony?

A. Yes.

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance

**Expert Testimony Appearances
of
Richard A. Baudino
As of August 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
3/83	1780	NM	New Mexico Public Service Commission	Boles Water Co.	Rate design, rate of return.
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design.
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
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Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc.	PGE Industrial Intervenors	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Comm.	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Richard A. Baudino
As of August 2014

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112		AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661		Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01		Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103		Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797		Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Elec. Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR		Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Gp.	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065		The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532		The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI		South Florida Hospital and Health Care Assn.	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana PSC	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Gp. Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation
03/10	09-1352-E-42T	WV	West Virginia Energy Users Gp.	Monongahela Power, Potomac Edison	Return on equity, rate of return
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design

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Date	Case	Jurisdict.	Party	Utility	Subject
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Compay	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Gp.	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Svc. Of Colorado	Return on equity, wtd. cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Assn.	Florida Power and Light Co,	Return on equity, wtd. cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pannsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

Expert Testimony Appearances
of
Richard A. Baudino
As of August 2014

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Gp.	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design

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	DEVELOPMENT OF ALLOCATED COST OF SERVICE	TOTAL CLASSIFICATION	SMALL CUSTOMER CLASS	MEDIUM CUSTOMER CLASS	LARGE CUSTOMER CLASS	STREETLIGHTING&OTHER CUSTOMER CLASS
	DEVELOPMENT OF RATE BASE					
	Production Plant	4,462,729,484	2,187,819,874	279,036,537	1,995,036,790	836,283
	Distribution Substations	541,187,245	274,263,682	44,853,671	216,441,088	5,628,805
	Distribution Overhead	1,160,245,299	931,027,462	62,731,499	132,298,734	34,187,604
	Distribution Underground	1,343,945,304	973,724,638	103,843,058	250,437,517	15,940,090
	Distribution Transformers Capacitors	14,471,060	7,333,665	1,199,363	5,787,520	150,511
	Distribution Transformers Line Transformers	544,262,985	435,895,447	37,489,403	64,727,963	6,150,172
	Distribution Transformers Regulators	9,089,970	4,606,629	753,378	3,635,420	94,543
	Distribution Services	239,151,606	234,671,736	2,777,610	1,702,259	0
	Distribution Meters	138,281,955	117,342,781	5,811,284	14,968,287	159,602
	Distribution Installations on Customer Premises	9,334,281	0	0	418,704	8,915,577
	Distribution Leased Property	9,998	0	0	9,998	0
	Distribution Street Lighting	23,973,683	0	0	0	23,973,683
	General Plant	449,050,656	265,949,794	25,430,093	150,963,232	6,707,537
1	ELECTRIC PLANT IN SERVICE	8,935,733,526	5,432,635,709	563,925,897	2,836,427,512	102,744,408
	Production	1,631,470,887	799,816,445	102,009,317	729,339,399	305,726
	Distribution Substations	181,816,652	92,141,315	15,068,988	72,715,302	1,891,047
	Distribution Overhead Lines	338,876,657	271,928,250	18,322,195	38,640,926	9,985,286
	Distribution Underground Lines	476,666,108	345,357,458	36,830,715	88,824,356	5,653,579
	Distribution Transformers	238,274,834	187,924,400	16,551,026	31,115,793	2,683,616
	Distribution Services	122,957,001	120,653,728	1,428,076	875,197	0
	Distribution Meters	89,169,960	75,667,510	3,747,358	9,652,174	102,918
	Distribution Installations on Customer Premises	8,218,417	0	0	368,650	7,849,767
	Distribution Leased Property	12,210	0	0	12,210	0
	Distribution Street Lighting	12,951,927	0	0	0	12,951,927
	General Plant	179,988,898	106,598,242	10,192,913	60,509,222	2,688,521
2	LESS: ACCUMULATED DEPRECIATION	3,280,403,551	2,000,087,347	204,150,589	1,032,053,229	44,112,386
3	PLANT HELD FOR FUTURE USE	0	0	0	0	0
4	CONSTRUCTION WORK IN PROGRESS	0	0	0	0	0
5	NET PLANT	5,655,329,975	3,432,548,362	359,775,308	1,804,374,283	58,632,022
.	ADDITIONS					
	Fossil Fuel Working Capital	118,515,551	51,325,529	7,635,957	58,739,862	814,202
6	FUEL INVENTORY	118,515,551	51,325,529	7,635,957	58,739,862	814,202
	Materials and Supplies for Production	63,701,912	31,229,388	3,983,025	28,477,563	11,937
	Materials and Supplies for Distribution	8,913,636	6,598,617	574,740	1,529,396	210,883
	Materials and Supplies for General	44,829,852	26,550,434	2,538,750	15,071,038	669,630
7	MATERIAL AND SUPPLIES	117,445,400	64,378,439	7,096,514	45,077,996	892,451
	Production	-606,582,608	-297,372,603	-37,927,172	-271,169,163	-113,669
	Distribution	-789,458,458	-584,423,020	-50,903,252	-135,454,805	-18,677,381
	General	-36,180,536	-21,427,886	-2,048,932	-12,163,284	-540,434
8	ACCUMULATED DEFERRED TAXES	-1,432,221,602	-903,223,509	-90,879,357	-418,787,252	-19,331,484
	Customer Advances	26,129,743	19,874,958	1,738,107	3,993,626	523,053
9	CUSTOMER ADVANCES	26,129,743	19,874,958	1,738,107	3,993,626	523,053
10A	WORKING CAPITAL ASSETS	0	0	0	0	0
10B	WORKING CAPITAL LIABILITIES	0	0	0	0	0
11	TOTAL RATE BASE	4,432,939,581	2,625,153,864	281,890,316	1,485,411,264	40,484,138
.	DEVELOPMENT OF RETURN					
	Billed Electric Revenue	2,894,622,841	1,457,365,565	196,963,689	1,210,599,801	29,693,786
12	TOTAL SALES REVENUE	2,894,622,841	1,457,365,565	196,963,689	1,210,599,801	29,693,786
	Opportunity Sales - Demand Related	2,035,256	997,769	127,256	909,849	381
	Opportunity Sales - Energy Related - On Peak	88,325,776	34,787,642	6,559,007	46,834,274	144,853
	Opportunity Sales - Energy Related - Off Peak	101,686,467	46,421,906	5,954,759	48,292,937	1,016,865
13	OPPORTUNITY SALES	192,047,498	82,207,317	12,641,022	96,037,060	1,162,099
	Forfeited Discounts	7,255,200	3,690,660	498,795	3,065,745	0
	Miscellaneous Services	2,142,200	2,034,541	41,222	62,290	4,146
	Pole Rental	732,720	587,964	39,616	83,550	21,590
	Other Rental	2,543,176	1,506,194	144,022	854,973	37,988
	Distribution Revenue from Michigan Retail Access Customers	0	0	0	0	0
	CASPR Amortization Adjustment	-5,089,566	-2,204,138	-327,921	-2,522,541	-34,965
	SSR Payments for PIPP	48,810,320	21,138,285	3,144,849	24,191,859	335,327
	Miscellaneous	303,827	131,578	19,576	150,586	2,087
	Wisconsin Fuel Deferral	18,907,000	8,188,054	1,218,178	9,370,876	129,891
	Nox Revenue & Point Beach Reg Asset	-1,620,884	-701,956	-104,434	-803,359	-11,135
	Edgewater 5 Regulatory Liability	-410,670	-192,216	-25,981	-191,331	-1,142
	Public Benefits Residual Fund	-754	-754	0	0	0
	Sales Tax Discount	12,000	6,023	748	5,157	72
	Black Start Revenue	5,331,228	2,479,891	347,666	2,476,197	27,474
	Miscellaneous Production Related Revenue	7,885,448	3,414,951	508,059	3,908,264	54,173
14	TOTAL OTHER OPERATING REVENUE	86,801,245	40,079,078	5,504,397	40,652,265	565,506
15	TOTAL OPERATING REVENUES	3,173,471,585	1,579,651,960	215,109,108	1,347,289,126	31,421,391

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	DEVELOPMENT OF ALLOCATED COST OF SERVICE	TOTAL CLASSIFICATION	SMALL CUSTOMER CLASS	MEDIUM CUSTOMER CLASS	LARGE CUSTOMER CLASS	STREETLIGHTING&OTHER CUSTOMER CLASS
	OPERATIONS AND MAINTENANCE					
	On-Peak Fuel	274,811,285	103,158,254	19,449,886	151,773,603	429,542
	Off-Peak Fuel	343,900,072	156,997,261	20,138,788	163,325,022	3,439,001
	Production Expenses - Demand Related	173,907,844	85,257,024	10,873,758	77,744,472	32,589
	Production Expenses - Energy Related	34,351,650	14,876,669	2,213,277	17,025,708	235,996
	Production Expenses - Supervision & Engineering	26,408,403	12,600,805	1,662,725	12,099,515	45,358
	Purchased Power - Non PBNP PPA - Demand	0	0	0	0	0
	Purchased Power - Non PBNP PPA - On-Peak Energy	-1,753,249	-690,528	-130,195	-929,651	-2,875
	Purchased Power - Non PBNP PPA - Off-Peak Energy	21,074,403	9,620,887	1,234,117	10,008,656	210,744
	Purchased Power - Non PBNP PPA - Total Energy	0	0	0	0	0
	Purchased Power - Not Allocated to FERC MISO - On-Peak	-1,615,224	-636,166	-119,945	-856,464	-2,649
	Purchased Power - Not Allocated to FERC MISO - Off-Peak	-2,206,855	-1,007,474	-129,233	-1,048,080	-22,069
	Non-Monitored Purchased Power - Demand-Related	50,860,903	24,934,179	3,180,128	22,737,065	9,531
	Non-Monitored Purchased Power - On-Peak Energy	13,991,155	5,510,501	1,038,973	7,418,736	22,945
	Non-Monitored Purchased Power - Off-Peak Energy	1,974,934	901,597	115,652	937,936	19,749
	Non-Monitored PP - Total Energy	2,752,632	1,192,083	177,352	1,364,287	18,911
	Point Beach Nuclear Plant PPA - Demand	252,422,833	117,975,750	15,975,232	117,749,811	722,039
	Point Beach Nuclear Plant PPA - On-Peak Energy	62,337,475	28,157,087	4,190,281	29,942,206	47,902
	Point Beach Nuclear Plant PPA - Off-Peak Energy	73,139,989	34,869,748	4,457,121	33,512,337	300,783
	Power the Future Costs	402,323,700	197,236,196	25,155,684	179,856,428	75,393
	Non-Firm Credit	-10,792,320	0	0	-10,792,320	0
	Non-Firm Load Cost	10,637,211	5,214,814	665,102	4,755,302	1,993
	Transmission	253,389,600	117,378,194	16,479,095	118,218,908	1,313,403
	Not Used	0	0	0	0	0
	Distribution Substations	7,553,869	3,828,161	626,066	3,021,076	78,567
	Distribution Overhead Lines	45,246,320	36,307,466	2,446,353	5,159,280	1,333,221
	Distribution Underground Lines	8,981,034	6,507,001	693,940	1,673,571	106,521
	Distribution Transformers	395,166	311,662	27,449	51,604	4,451
	Distribution Meters	4,215,626	3,577,280	177,161	456,319	4,866
	Distribution Installations on Customer Premises	-206,914	0	0	-9,281	-197,632
	Distribution Supervision & Engineering	2,685,407	1,981,452	155,710	405,947	142,297
	Distribution Street Lighting	2,298,916	0	0	0	2,298,916
	Distribution Other	10,713,013	7,904,697	621,182	1,619,461	567,673
	Distribution Dispatching	4,930,276	2,498,573	408,622	1,971,802	51,279
	Customer Accounting	26,236,814	21,699,270	343,777	4,149,598	44,170
	Uncollectibles (FERC Acct 904)	30,693,791	29,686,182	140,997	866,612	0
	Wisconsin Conservation Escrow	50,851,070	24,906,830	3,466,969	22,468,113	9,158
	Customer Service Expenses	13,426,578	12,751,811	258,365	390,414	25,988
	Sales Expenses	0	0	0	0	0
	Not Used	0	0	0	0	0
	Property Insurance	3,233,322	1,939,354	206,465	1,051,277	36,226
	Regulatory Expenses for WI, MI and FERC	1,791,442	899,106	111,736	769,829	10,771
	All Other A&G	133,963,856	79,339,957	7,586,479	45,036,382	2,001,038
16	TOTAL OPERATION AND MAINTENANCE COSTS	2,328,926,026	1,147,685,684	143,899,068	1,023,925,479	13,415,795
.	DEPRECIATION					
	Production	129,887,199	63,676,231	8,121,324	58,065,303	24,340
	Distribution Substations	13,774,638	6,980,732	1,141,644	5,508,995	143,268
	Distribution Overhead Lines	29,531,292	23,697,096	1,596,682	3,367,351	870,164
	Distribution Underground Lines	34,206,940	24,783,851	2,643,079	6,374,293	405,717
	Distribution Transformers	14,452,614	11,398,597	1,003,906	1,887,335	162,775
	Distribution Services	6,087,037	5,973,013	70,697	43,327	0
	Distribution Meters	3,519,639	2,986,682	147,912	380,982	4,062
	Distribution Installations on Customer Premises	237,582	0	0	10,657	226,925
	Distribution Leased Property	254	0	0	254	0
	Distribution Street Lighting	610,193	0	0	0	610,193
	General Plant	34,948,444	20,698,181	1,979,158	11,749,076	522,030
17	DEPRECIATION EXPENSE	267,255,834	160,194,382	16,704,403	87,387,573	2,969,475
	TAXES					
	Other Taxes - Carline and Use Tax	192,105	83,195	12,377	95,213	1,320
	Other Taxes - Property - Production Plant	7,918,192	3,881,835	495,093	3,539,781	1,484
	Other Taxes - Property - Michigan Distribution Plant	0	0	0	0	0
	Other Taxes - Payroll	18,016,231	10,670,094	1,020,273	6,056,752	269,111
	Other Taxes - Taxes on Company Use	78,720	46,622	4,458	26,464	1,176
	Other Taxes - Insurance	358,536	215,419	22,712	115,983	4,422
	Other Taxes - PSCW & MPSC Assessment	3,000,000	1,505,668	187,117	1,289,177	18,038
	Other Taxes - Wisconsin License Fee	90,853,596	45,598,457	5,666,751	39,042,122	546,267
18	TAXES OTHER THAN INCOME TAXES	120,417,380	62,001,290	7,408,781	50,165,492	841,817

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	DEVELOPMENT OF ALLOCATED COST OF SERVICE	TOTAL CLASSIFICATION	SMALL CUSTOMER CLASS	MEDIUM CUSTOMER CLASS	LARGE CUSTOMER CLASS	STREETLIGHTING&OTHER CUSTOMER CLASS
	Depreciation Removal & Repair - WI Production	100,238,440	49,141,148	6,267,507	44,811,001	18,784
	Depreciation Removal & Repair - WI Distribution	147,950,865	109,525,574	9,539,679	25,385,320	3,500,291
	Depreciation Removal & Repair - WI General	21,829,568	12,928,539	1,236,226	7,338,731	326,072
	STATE DEPRECIATION, REMOVAL & REPAIR	270,018,872	171,595,262	17,043,411	77,535,052	3,845,147
	Other Deferred Tax Adj for State - Production	39,813,731	19,518,385	2,489,393	17,798,493	7,461
	Other Deferred Tax Adj for State - Distribution	73,500,638	54,411,305	4,739,225	12,611,195	1,738,913
	Other Deferred Tax Adj for State - General	17,743,432	10,508,530	1,004,825	5,965,042	265,036
	Contributions in Aid of Construction - State	-28,651,983	-21,586,779	-1,887,809	-4,337,595	-839,800
	Conservation - State	-390,020	-168,906	-25,129	-193,306	-2,679
	TOTAL OTHER DEFERRED STATE TAXES	102,015,798	62,682,534	6,320,504	31,843,829	1,168,931
	NET DEFERRABLE ITEMS	372,034,670	234,277,796	23,363,916	109,378,881	5,014,078
	DEFERRED TAX @	17,791,021	11,203,368	1,117,283	5,230,593	239,778
	Adjustments - WI Production	248,161	121,659	15,517	110,939	47
	Adjustments - WI Distribution	366,283	271,153	23,617	62,847	8,666
	Adjustments - WI General	54,043	32,007	3,061	18,168	807
	ADJUSTMENTS TO STATE DEFERRED TAXES	668,487	424,819	42,194	191,954	9,519
	TOTAL STATE DEFERRED TAXES	18,459,508	11,628,187	1,159,477	5,422,547	249,297
	STATE DEPRECIATION, REMOVAL & REPAIR	270,018,872	171,595,262	17,043,411	77,535,052	3,845,147
	TOTAL OTHER DEFERRED STATE TAXES	102,015,798	62,682,534	6,320,504	31,843,829	1,168,931
	TOTAL ADDITIONS	372,034,670	234,277,796	23,363,916	109,378,881	5,014,078
	Depreciation Payback - State - Production	3,355,764	1,645,138	209,822	1,500,174	629
	Depreciation Payback - State - Distribution	4,953,058	3,666,667	319,367	849,843	117,182
	Depreciation Payback - State - General	730,801	432,816	41,386	245,683	10,916
	TOTAL STATE DEPRECIATION PAYBACK	9,039,623	5,744,621	570,575	2,595,700	128,727
	50% Meal Disallowance	556,522	329,599	31,516	187,093	8,313
	TOTAL SUBTRACTIONS	9,596,145	6,074,221	602,091	2,782,793	137,040
	TOTAL ADDITIONS & SUBTRACTIONS	362,438,525	228,203,575	22,761,824	106,596,087	4,877,038
	TOTAL OPERATING REVENUES	3,173,471,585	1,579,651,960	215,109,108	1,347,289,126	31,421,391
	O&M EXPENSE	2,328,926,026	1,147,685,684	143,899,068	1,023,925,479	13,415,795
	DEPRECIATION EXPENSE	267,255,834	160,194,382	16,704,403	87,387,573	2,969,475
	TAXES OTHER THAN INCOME TAXES	120,417,380	62,001,290	7,408,781	50,165,492	841,817
	Interest Long Term Debt	111,597,321	65,263,692	7,123,888	38,094,326	1,115,415
	NET OPERATING INCOME	345,275,023	144,506,912	39,972,968	147,716,255	13,078,888
	TAXABLE INCOME	-17,163,501	-83,696,663	17,211,144	41,120,168	8,201,850
	STATE INCOME TAX @	-1,262,729	-6,157,611	1,266,234	3,025,234	603,415
	WI Environmental Tax	9,277	5,425	592	3,167	93
	Michigan Income Tax Adjustment	226,104	132,229	14,434	77,182	2,260
19	STATE INCOME TAXES	-1,027,348	-6,019,957	1,281,259	3,105,583	605,767
	Depreciation Removal & Repair - FED Production	7,669,562	3,759,946	479,547	3,428,632	1,437
	Depreciation Removal & Repair - FED Distribution	11,320,557	8,380,421	729,935	1,942,374	267,827
	Depreciation Removal & Repair - FED General	1,670,390	989,287	94,596	561,557	24,951
	FEDERAL DEPRECIATION, REMOVAL & REPAIR	20,660,510	13,129,654	1,304,077	5,932,564	294,215
	Other Deferred Tax Adj for Fed - Production	-681,343	-334,023	-42,602	-304,590	-128
	Other Deferred Tax Adj for Fed - Distribution	68,547,579	50,744,638	4,419,859	11,761,352	1,621,731
	Other Deferred Tax Adj for Fed - General	17,012,631	10,075,713	963,439	5,719,359	254,120
	Contributions in Aid of Construction - Fed	-28,651,983	-21,586,779	-1,887,809	-4,337,595	-839,800
	Conservation - Fed	-390,020	-168,906	-25,129	-193,306	-2,679
	TOTAL OTHER DEFERRED FEDERAL TAXES	55,836,865	38,730,643	3,427,758	12,645,220	1,033,244
	NET DEFERRABLE ITEMS	76,497,375	51,860,297	4,731,835	18,577,784	1,327,460
	DEFERRED TAX @	26,774,081	18,151,104	1,656,142	6,502,224	464,611
	Adjustments - FED Production	-276,065	-135,339	-17,261	-123,413	-52
	Adjustments - FED Distribution	-407,468	-301,642	-26,273	-69,913	-9,640
	Adjustments - FED General	-60,120	-35,606	-3,405	-20,211	-898
	ADJUSTMENTS TO FEDERAL DEFERRED TAXES	-743,653	-472,587	-46,939	-213,538	-10,590
	TOTAL FEDERAL DEFERRED TAXES	26,030,428	17,678,517	1,609,203	6,288,687	454,021
	FEDERAL DEPRECIATION, REMOVAL & REPAIR	-20,660,510	-13,129,654	-1,304,077	-5,932,564	-294,215
	TOTAL OTHER DEFERRED FEDERAL TAXES	-55,836,865	-38,730,643	-3,427,758	-12,645,220	-1,033,244
	Depreciation Payback - Federal - Production	3,453,250	1,692,930	215,918	1,543,755	647
	Depreciation Payback - Federal - Distribution	5,096,946	3,773,185	328,644	874,531	120,586
	Depreciation Payback - Federal - General	752,031	445,390	42,588	252,820	11,233
	TOTAL FEDERAL DEPRECIATION PAYBACK	9,302,227	5,911,505	587,150	2,671,106	132,466
	50% Meal Disallowance	556,522	329,599	31,516	187,093	8,313
	Section 199 Deduction	-37,139,309	-18,207,270	-2,322,172	-16,602,908	-6,960
	STATE INCOME TAXES	1,027,348	6,019,957	-1,281,259	-3,105,583	-605,767
	TOTAL ADDITIONS & SUBTRACTIONS	-102,750,588	-57,806,505	-7,716,599	-35,428,076	-1,799,408
	NET OPERATING INCOME	345,275,023	144,506,912	39,972,968	147,716,255	13,078,888
	TAXABLE INCOME	242,524,435	86,700,407	32,256,369	112,288,179	11,279,480
	FEDERAL INCOME TAX @	84,883,552	30,345,142	11,289,729	39,300,863	3,947,818
	Wind Energy & Biomass Tax Credits	-15,422,283	-6,678,928	-993,658	-7,643,746	-105,951
	Section 199 Amortization	5,671,273	2,780,299	354,602	2,535,309	1,063
20	FEDERAL INCOME TAXES	75,132,543	26,446,514	10,650,673	34,192,426	3,842,930

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	DEVELOPMENT OF ALLOCATED COST OF SERVICE	TOTAL CLASSIFICATION	SMALL CUSTOMER CLASS	MEDIUM CUSTOMER CLASS	LARGE CUSTOMER CLASS	STREETLIGHTING&OTHER CUSTOMER CLASS
	Investment Tax Credit - Production	-315,523	-154,683	-19,728	-141,053	-59
	Investment Tax Credit - Distribution	-465,707	-344,755	-30,028	-79,906	-11,018
	Investment Tax Credit - General	-68,713	-40,695	-3,891	-23,100	-1,026
21	INVESTMENT TAX CREDIT - NET	-849,943	-540,133	-53,648	-244,059	-12,103
	Michigan Deferred Income Taxes	728,339	425,943	46,494	248,622	7,280
22	TOTAL OPERATING EXPENSE	2,835,072,767	1,419,500,426	182,705,712	1,210,492,350	22,374,279
23	OPERATING INCOME	338,398,817	160,151,533	32,403,397	136,796,776	9,047,111
.	ADJUSTMENTS TO OPERATING INCOME					
24	TOTAL ADJUSTMENTS TO OPERATING INCOME	0	0	0	0	0
25	ADJUSTED OPERATING INCOME	338,398,817	160,151,533	32,403,397	136,796,776	9,047,111
26	EARNED RATE OF RETURN	7.6337%	6.1007%	11.4950%	9.2094%	22.3473%
27	REQUIRED RATE OF RETURN	8.6044%	8.6044%	8.6044%	8.6044%	8.6044%
28	INCOME DEFICIENCY	43,030,836	65,728,272	-8,148,312	-8,985,446	-5,563,678
29	REVENUE DEFICIENCY $	71,767,690	109,622,926	-13,589,918	-14,986,106	-9,279,213
.	ADJUSTMENTS TO REVENUE DEFICIENCY					
	Tax Asset & Liability Settlment Items	0	0	0	0	0
	Loss Adj from PSCW Staff	-1,856,704	-804,083	-119,627	-920,238	-12,756
	Carrying Costs for ERGS Amortization	-2,481,538	-1,074,680	-159,885	-1,229,925	-17,048
	Tax Amortizations	-2,325,653	-1,360,075	-148,460	-793,874	-23,245
	Section 1603 Tax Grant Credit (Line Item on Bills)	-12,803,795	-6,276,965	-800,570	-5,723,861	-2,399
30	TOTAL ADJUSTMENTS TO REVENUE DEFICIENCY FOR 2015	-19,467,690	-9,515,802	-1,228,542	-8,667,897	-55,448
31	REVENUE DEFICIENCY AFTER SPECIFIED ADJUSTMENTS $	52,300,000	100,107,124	-14,818,460	-23,654,003	-9,334,661
32	REVENUE DEFICIENCY AFTER SPECIFIED ADJUSTMENTS %	1.8%	6.9%	-7.5%	-2.0%	-31.4%
	Wisconsin Fuel Deferral	18,907,000	8,188,054	1,218,178	9,370,876	129,891
	Section 1603 Tax Grant Credit	12,803,795	6,276,965	800,570	5,723,861	2,399
	CASPR Amortization Adjustment	-5,089,566	-2,204,138	-327,921	-2,522,541	-34,965
33	ADJUSTMENTS TO REQUSETED REVENUE FOR 2015	26,621,229	12,260,881	1,690,827	12,572,196	97,325
34	REVENUE DEFICIENCY FOR 2015 RATE DESIGN $	78,921,229	112,368,005	-13,127,633	-11,081,808	-9,237,336
35	REVENUE DEFICIENCY FOR 2015 RATE DESIGN %	2.7%	7.7%	-6.7%	-0.9%	-31.1%
36	REVENUE REQUIREMENT FOR 2015 RATE DESIGN	2,973,544,070	1,569,733,571	183,836,056	1,199,517,993	20,456,450
	Wisconsin Fuel Deferral	18,907,000	8,188,054	1,218,178	9,370,876	129,891
	Section 1603 Tax Grant Credit	12,803,795	6,276,965	800,570	5,723,861	2,399
	CASPR Amortization Adjustment	-5,089,566	-2,204,138	-327,921	-2,522,541	-34,965
37	REVENUE DEFICIENCY FOR 2016 RATE DESIGN $	26,621,229	12,260,881	1,690,827	12,572,196	97,325
38	REVENUE DEFICIENCY FOR 2016 RATE DESIGN %	0.9%	0.8%	0.9%	1.0%	0.5%

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001** ***et al.***

SUMMARY OF THE DIRECT TESTIMONY OF RICHARD A. BAUDINO

The purpose of the Direct Testimony of Mr. Richard A. Baudino is to address the allowed return on equity to use for the purpose of calculating the Monthly Capacity Charge for unit power sales in Entergy Services, Inc.'s ("ESI") proposed Unit Power Sales/Designated Power Purchases tariff.

Based on current financial market conditions, Mr. Baudino recommends that the Federal Energy Regulatory Commission ("FERC" or "Commission") adopt a 9.00% return on equity for the Monthly Capacity Charge in this proceeding. This recommendation is based on the median result from the FERC's two-stage Discounted Cash Flow ("DCF") Model formulation as set forth in its Opinion No. 531, Order on Initial Decision, Docket No. EL11-66-001. Mr. Baudino also presents the results of a second approach to the DCF that employs his standard method of estimating the investor expected growth rate, which includes three separate sources for expected dividend and earnings growth. Both of these methods yield results that are similar.

In its Opinion No. 531, the Commission adopted a return on equity halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness produced by the DCF model. FERC expressed concerns with respect to using the midpoint of the DCF in that opinion due to (1) anomalous market conditions and (2) risks associated with investments in transmission facilities. Mr. Baudino's testimony shows that anomalous market conditions do not presently exist. The U.S. economy is in a low interest rate environment, which strongly suggests that the current FERC-allowed return on equity of 11% for capacity charges reflected in the proposed Tariff should be lowered significantly. Mr. Baudino will also discuss why the risks of transmission investment are simply not present in the lower risk capacity purchase transactions between Entergy Arkansas, Inc. and other Entergy Operating companies. The current low interest rate environment and the lower risk nature of inter-company power purchases support using the median 9.00% return on equity recommendation from the FERC's two-stage DCF method in this proceeding.

Mr. Baudino also addresses the Direct Testimony and recommendations of Entergy witnesses Dr. William Avera and Mr. Adrien McKenzie. Their return on equity recommendation of 10.66% significantly overstates the current required return on equity for purposes of calculating the Monthly Capacity Charge. Mr.

Baudino demonstrates that their selection of a return on equity from the upper half of their DCF model calculations is not supported by current financial market conditions. Furthermore, their selection of an excessively high return on equity is based on a misreading of FERC's Opinion No. 531, which set a return on equity for the New England Transmission Owners ("NETOs"). The risks articulated by the FERC for transmission investment are not present in the capacity purchases under ESI's proposed Tariff.

Exhibit LC-1

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 9, 2014

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001** ***et al.***
	)	

DIRECT TESTIMONY OF RICHARD A. BAUDINO

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 LC-2 summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Louisiana Public Service Commission ("LPSC").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity to use for the purpose of calculating the Monthly Capacity Charge for unit power sales in Entergy Services, Inc.'s ("ESI") proposed Unit Power Sales/Designated Power Purchases tariff.

Based on current financial market conditions, I recommend that the Federal Energy Regulatory Commission ("FERC" or "Commission") adopt a 9.00% return on equity for the Monthly Capacity Charge in this proceeding. This recommendation is based on the median result from the Federal Energy Regulatory Commission's two-stage Discounted Cash Flow ("DCF") Model formulation as set forth in its Opinion No. 531, Order on Initial Decision, Docket No. EL11-66-001. I also present the results of a second approach to the DCF that employs my standard method of estimating the investor expected growth rate, which includes three separate sources for expected dividend and earnings growth. Both of these methods yield results that are similar.

In its Opinion No. 531, the Commission adopted a return on equity halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness produced by the DCF model. FERC expressed concerns with respect to using the midpoint of the DCF in that opinion due to (1) anomalous market conditions and (2) risks associated with investments in transmission facilities. I will show in my testimony that anomalous market conditions do not presently exist. The U.S. economy is in a low interest rate environment, which strongly suggests that the current FERC-allowed return on equity of 11% for capacity charges reflected in the proposed Tariff should be lowered significantly. I will also discuss why the risks of transmission investment are simply not present in the lower risk capacity purchase transactions between Entergy Arkansas, Inc. and other Entergy Operating companies. The current low interest rate environment and the lower risk nature of inter-company power purchases support using the median 9.00% return on equity recommendation from the FERC's DCF method in this proceeding.

I also address the Direct Testimony and recommendations of Entergy witnesses Dr. William Avera and Mr. Adrien McKenzie. Their return on equity recommendation of 10.66% significantly overstates the current required return on equity for purposes of calculating the Monthly Capacity Charge. I will show that their selection of a return on equity from the upper half of their DCF model calculations is not supported by current financial market conditions. Contrary to their assertions, anomalous market conditions do not exist today. Furthermore, their selection of an excessively high return on equity is based on a misreading of FERC's Opinion No. 531, which set a return on equity for the New England Transmission Owners ("NETOs"). The risks articulated by the FERC for transmission investment are not present in the capacity purchases under ESI's proposed Tariff.

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. Generally speaking, interest rates have declined over the last 10 years. Exhibit LC-3 presents a graphic depiction of the trend in interest rates from January 2005 through August 2014. 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. In January 2005, the average public utility bond yield was 5.80% and the 20-year Treasury Bond yield was 4.77%. As of August 2014 the average public utility bond yield was 4.39% and represents a decline of 141 basis points, or 1.41% from January 2005. Likewise, the 20-year Treasury bond declined to 2.92% in August 2014, a decline of 1.85% from January 2005.

In 2008, however, 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 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 LC-3.

Beginning in 2009, 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

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

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 substantially to 1.63%. This is much closer to the historical spread.

Beginning in January 2013, utility bond yields rose throughout the year but began to fall at the beginning of 2014. As of September 30, 2014 Moody's Credit Trends reported that the yield on the average public utility bond was 4.37%. This is not significantly different from the yield at the end of 2012.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit LC-3?

A. Yes. Beginning in September 2011, the Federal Reserve initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist" was designed by the Federal Reserve to lower long-term interest rates and support the economic recovery. On June 19, 2013, the Federal Open Market Committee ("FOMC") issued a press release indicating that it intended to extend "Operation Twist." 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.

More recently, the Federal Reserve began to pare back its purchases of securities. For example, on January 29, 2014 the Federal Reserve stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Federal Reserve continued to reduce these purchases throughout the year and in a press release issued September 17, 2014 the Federal Reserve further reduced its long-term Treasury purchases to $10 billion per month and its purchases of agency mortgage-backed securities from $10 billion to $5 billion per month. The press release stated the following:

> The Committee's sizable and still-increasing holdings of longer-term securities should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative, which in turn should promote a stronger economic recovery and help to ensure that inflation, over time, is at the rate most consistent with the Committee's dual mandate.

The press release also noted that "a highly accommodative stance of monetary policy remains appropriate" and that the 0% - 0.25% target for the

Federal Funds rate will be in effect "for a considerable amount of time after the asset purchase program ends ..."

Q. Since the Federal Reserve's announcements of scaling back its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields so far in 2014?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. The closing yield for the week ending September 26, 2014 was 3.01%, a decline of 51 basis points since January. Utility bond yields have followed a similar trend, starting January at 4.72% and declining to 4.37% at the end of September.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[2]

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2 Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Federal Reserve will begin to raise short-term interest rates. However, the timing and the level of any such move are not known at this time. It is important to realize that any investor expectations of higher interest rates are already embodied in current securities prices, which include debt securities. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

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

A. The August 22, 2014 Value Line report on the Electric Utility (East) group of companies noted the following:

> Most electric utility stocks performed very well in the first half of 2014, thanks in part to a decline in the interest rate on the 10-year U.S. Treasury note since the start of the year. Many of these equities climbed more than 10%. In recent weeks, however, utility stocks have given back some of these gains. Perhaps the market is worried about the time that the Federal Reserve will start raising interest rates, but we think the latest declines are merely a correction.

Value Line's September 19, 2014 review of the Electric Utility (Central) group of companies also noted:

> In the last quarter of the 20th century, electric utilities underinvested in transmission. Managements were more focused on generation and distribution. So, new laws and orders from the Federal Energy Regulatory Commission (FERC) were enacted in order to stimulate the industry's spending on transmission. In addition, FERC allowed returns on equity for transmission that were (and still are) more

> generous than those allowed by state regulatory commissions. What's more, many projects are eligible for incentive "adders" that increase the allowed ROE. All of this has had the desired effect: Utilities have stepped up their investment in transmission. Besides the need to replace aging equipment, transmission spending has been driven by the need to enhance the reliability of the grid, expand transmission capacity, and connect wind and solar projects (which are usually built in remote areas) to the grid.
>
> In recent years, some transmission users have complained that the ROEs that FERC allows are too generous. The first region that was targeted was New England. FERC agreed to hear their complaint, and in June lowered the allowed ROE for transmission users in the region. (Two other complaints are pending.)

Edison Electric Institute ("EEI") recently reported that the utility industry's average credit rating improved to BBB+ by mid-year 2014.[3] EEI also reported that in early 2014 both S&P and Moody's published industry-level outlooks describing why they expect U.S. regulated utilities to maintain stable credit profiles throughout the rest of the year.[4]

The *2014 Ibbotson SBBI Classic Yearbook* published by Morningstar stated the following with respect to the outlook for utilities in 2014:

> Adding to the sector's attractiveness going into 2014 is its average 4 percent dividend yield, nearly double the average S&P 500 dividend yield and more than 1 percentage point higher than 10-year U.S

3 *EEI Q2 2014 Financial Update*, page 1.

4 *Ibid,* page 5.

> Treasuries. Our analysis of returns going back 20 years suggests that 10-year U.S. Treasuries could climb to 4 percent from 3 percent today, with little impact on utilities' total returns. We think utilities with 3 percent to 5 percent earnings growth prospects during the next few years offer a compelling risk-adjusted total-return package for any investor.[5]

Q. What do you conclude from the aforementioned quotes?

A. Utilities continue to be safe, solid stock choices for investors. Even with uncertainty regarding the Federal Reserve concluding its maturity extension program, utilities' prices have made solid gains since the beginning of the year. Morningstar indicated that interest rates could rise 100 basis points with little effect on utilities' overall return. The current low interest rate environment continues to favor utility stocks.

It appears that the Fed will continue a relatively accommodating stance with respect to monetary policy and has signaled that it does not intend to raise short-term interest rates at this time. The volatile economic conditions that were present in the 2008 - 2009 period are over and the U.S. economy continues to slowly recover from the recession.

All things considered, current economic conditions do not support an 11% return on equity for the Entergy Operating companies.

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5 *2014 Ibbotson SBBI Classic Yearbook,* Morningstar, page 31.

Q. Have you reviewed the FERC's Opinion No. 531[6]?

A. Yes.

Q. Did the FERC express concerns with respect to the anomalous market conditions that were present in the record of that proceeding?

A. Yes. On page 69, paragraph 145 the FERC's Opinion noted anomalous market conditions that made it more difficult to determine a return on equity sufficient to attract capital and satisfy the *Hope* and *Bluefield* standards. Based on this concern, the FERC looked at several alternative return on equity approaches in order to assist its determination of a fair return on equity. The Commission finally decided that the return on equity should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness produced by the Discounted Cash Flow model.

Q. Did the FERC also express considerations with respect to setting an appropriate return on equity for transmission companies in its Opinion?

A. Yes. The FERC stated the following in paragraph 149:

> The financial and business risks faced by investors in companies whose focus is electric transmission infrastructure differ in some key respects when compared to other electric infrastructure investment, particularly state-regulated electric distribution. For example, investors providing capital for electric transmission infrastructure face risks including the following: long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring regulatory

6 *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.*, (Opinion No. 531), 147 FERC ¶ 61.234 (2014).

> approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects that are large relative to the size of a balance sheet, and shorter investment history. We find that these factors increase the NETOs' risk relative to the state-regulated distribution companies. However, as noted above, the record in this proceeding indicates that the vast majority of state commission-authorized ROEs reflected on this record range from 9.8 percent to 10.74 percent, and our DCF analysis in this proceeding produces a midpoint of 9.39 percent, we find that the record evidence concerning state commission authorized ROEs supports setting the NETOs' base ROE above the midpoint.

Q. In your opinion, are current market conditions anomalous?

A. No. As I stated earlier, the U.S. economy has stabilized since the severe recession of 2008 - 2009. The unemployment rate has dropped from a high of 10.0% in October 2009 to 5.9% as of September 2014. Growth in U.S. Gross Domestic Product has also recovered, with an annualized increase of 4.6% in the second quarter of 2014 according to the U.S. Department of Commerce's Bureau of Economic Analysis[7]. The Federal Reserve is pursuing an accommodative monetary policy, with low short-term interest rates expected to continue for some time. Indeed, the anomalous conditions that existed during the recession are no longer present.

Q. Are the financial and business risks that FERC mentioned in paragraph 149 of its Opinion relevant to setting the allowed ROE for the Monthly Capacity Charge in ESI's proposed Tariff?

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7 Reported by the Bureau of Economic Analysis, September 26, 2014, http://bea.gov/newsreleases/national/gdp/gdpnewsrelease.htm

A. No. The risks FERC cited with respect to transmission infrastructure are simply not present with respect to capacity charges for unit sales under Entergy's proposed tariff for Unit Power Sales/Designated Power Purchases. In fact, unit sales under this proposed tariff are much lower risk since they only involve generation sales and purchases between Entergy's operating companies. The risk associated with such transactions bear no resemblance whatsoever to those enunciated by the FERC in Opinion No. 531. Mr. Kollen provides a broader discussion of the lower risk associated with the transactions pursuant to the Tariff in his Direct Testimony.

Q. When was the return on equity set by the FERC for the capacity charge for unit power sales between Entergy's Operating companies?

A. According to Entergy's response to STAFF 4-2, the FERC first accepted the 11% ROE for MSS-4 of the System Agreement in 1993. It is important to note that capital costs have declined dramatically since the early 1990s. Based on historical bond yields I obtained from the Federal Reserve's web site, the average yearly 30-year bond yields for the early 1990s were:

- 1990 - 8.61%
- 1991 - 8.14%
- 1992 - 7.67%
- 1993 - 6.60%

As of September 26, 2014, the 30-year Treasury bond yield was 3.25%. The large difference in bond yields suggests a much lower ROE for the Monthly Capacity Charge formula in this case.

Q. Are you aware of any recently authorized state commission returns on equity for Entergy Operating companies?

A. Yes. In its Order No. 35 dated August 15, 2014 in Docket No. 13-028-U, the Arkansas Public Service Commission ("APSC") authorized a return on equity for Entergy Arkansas, Inc. of 9.50%. In its Order No. 21, page 108 in that docket dated December 30, 2013, the APSC noted the following:

> The Commission does not find EAI's and Staffs "anomaly" arguments persuasive. Similar arguments can be made for any time period in recent U.S. economic and financial history. It is unclear what exactly constitutes "normal" economic and financial conditions, and, in particular, what constitutes a normal level of interest rates. As shown in Exhibit DCP-2, T. at E 2369, the interest rates on U.S. 10-year Treasury bonds has varied between 1.80% and 13.93% since 1981. The country is currently in a low interest rate environment. In the past, including the early 1980's, this Commission allowed higher ROEs, which corresponded with extremely high interest rates during that period. It would be inconsistent to now adjust allowed ROEs upward because of currently low interest rates. Further, the Fed has been pursuing those low interest rate policies for a number of years, a period which corresponds closely to the period of time new rates are effective for a typical utility.
> The allowed ROE should reflect current economic and financial conditions, not ignore those conditions.

I note that in its Order No. 35 in that docket, the APSC raised EAI's return on equity from 9.30% in Order No. 21 to 9.50%. The APSC based this change on temporary uncertainties relating to generation planning and transmission system operations associated with EAI exiting the Entergy System Agreement. The APSC also stated that this temporary period of uncertainty "will be brief and certainly complete before EAI's next rate case." (pages 14 and 15 of Order No. 35).

Q. What is your conclusion with respect to the quote from the APSC's Order No. 21?

A. I agree with the APSC's finding that the ROE should reflect current economic and financial conditions and not ignore those conditions. My return on equity analysis does, in fact, reflect current economic conditions that support my recommended 9.00% median return on equity in this proceeding using the FERC's two-stage DCF model. I shall also show in the final section of my testimony that the analyses presented by Dr. Avera and Mr. McKenzie inflate investors' required return on equity and ignore current market conditions.

Q. Does your return on equity recommendation reflect the FERC's preferred method of estimating the DCF?

A. Yes. I incorporated FERC's guidance regarding the method of selecting companies for the National Group, calculating the dividend yield, and for calculating the investor expected growth rate using a two-stage growth calculation. I will explain this in greater detail in the following section of my testimony.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for the Entergy Operating companies.

A. I employed two Discounted Cash Flow ("DCF") analyses using a group of regulated electric utilities. The first analysis employed the FERC's two-stage DCF model as set forth in its Opinion No. 531. The second DCF analysis employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. I also employed two Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

In this docket, my recommended return on equity of 9.00% follows FERC's two-stage DCF formulation as set forth in its Opinion No. 531. FERC was specific about how the DCF analysis should be conducted and about the inputs to be used. Therefore, I have followed the FERC's guidance to the best of my understanding in this proceeding.

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

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 perhaps some appreciation in the stock's value 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. 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 potential return available by investing in other risk-comparable firms.

Q. What are the major types of risk faced by 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), the amount of operating leverage, and quality of management are all 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. Additional debt means additional variability in the firm's earnings, leading to additional 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 total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's 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.

<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 the discounted present value of future cash flows. 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 typically 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 the Entergy Operating companies?

A. My first step was to select a group of publicly traded electric utility companies.

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

A. For purposes of this proceeding, I followed the FERC's guidance as set forth in Opinion No. 531 for selecting the group. This is similar to the approach that Dr. Avera and Mr. McKenzie used in their Direct Testimony and explained on pages 20 - 21. FERC's selection criteria are as follows:

- Companies included in the Electric Utility Industry groups compiled by Value Line.
- Electric utilities that paid common dividends over the last six months and have not announced a dividend cut since that time.
- Electric utilities with no ongoing involvement in mergers and/or acquisitions.
- Electric utilities that have been assigned a corporate credit rating from one notch below to one notch above the subject utility's credit rating. FERC considers both the Standard and Poor's credit rating and the Moody's issuer rating.

Q. Did you use the credit ratings and issuer ratings of all of the Entergy Operating companies in selecting your National Group?

A. No. ESI's proposed Tariff applies only when one or both of the operating companies are not in the System Agreement. As of this date, EAI is the only operating company that has withdrawn from the System Agreement and that is selling capacity to other operating companies. Thus, the return on equity in this proceeding should reflect EAI's credit profile to match the present application of the Tariff.

Q. Are you aware that Entergy Texas, Inc., Entergy Louisiana, LLC, and Entergy Gulf States Louisiana, LLC have filed notices to terminate their participation in the System Agreement?

A. Yes. According to ESI's response to STAFF 2-13, Entergy Texas, Inc. requested a termination date of October 18, 2018. Entergy Louisiana, LLC and Entergy Gulf States Louisiana, LLC requested a termination date of

February 14, 2019. Also, it is my understanding that Entergy Mississippi, Inc. will withdraw from the System Agreement in 2015, though it is not a seller of capacity. It will be several years before ESI's proposed Tariff would apply to these companies, except for those transactions where EAI is selling capacity to ELL. Further, these companies are presently buyers, not sellers, of capacity pursuant to the Entergy System Agreement Service Schedule MSS-4 ("MSS-4"). Therefore, it is reasonable to estimate EAI's return on equity for purposes of this proceeding.

Q. How did you select the companies for your National Group?

A. I reviewed the S&P credit ratings and Moody's issuer ratings of the Avera/McKenzie National Group in September and there were no ratings changes for any of the companies in that group. I then selected companies that were within one ratings notch above and below EAI's S&P credit rating of BBB and Moody's issuer rating of Baa2. The National Group selected by Dr. Avera and Mr. McKenzie met the other selection criteria set forth by the FERC in Opinion No. 531. This resulted in the National Group of electric utilities shown in Table 1.

TABLE 1
REVISED NATIONAL GROUP

	Company	S&P Corporate Rating	Moody's Long-term Rating
1	Ameren Corp.	BBB+	Baa2
2	American Elec Pwr	BBB	Baa1
3	Avista Corp.	BBB	Baa1
4	Black Hills Corp.	BBB	Baa1
5	Cleco Corp.	BBB+	Baa1
6	CMS Energy Corp.	BBB	Baa2
7	El Paso Electric	BBB	Baa1
8	Empire District Elec	BBB	Baa1
9	Entergy Corp.	BBB	Baa3
10	Great Plains Energy	BBB+	Baa2
11	Hawaiian Elec.	BBB-	Baa2
12	IDACORP, Inc.	BBB	Baa1
13	Otter Tail Corp.	BBB	Baa2
14	PG&E Corp.	BBB	Baa1
15	PNM Resources	BBB	Baa3
16	Pub Sv Enterprise Grp	BBB+	Baa2
17	SCANA Corp.	BBB+	Baa3
18	Sempra Energy	BBB+	Baa1
19	Westar Energy	BBB+	Baa1
		BBB	Baa1

Updated credit ratings and issuer ratings retreived September 22, 2014.

Q. Is this consistent with the approach you normally use to select a group of companies to estimate the DCF return on equity?

A. No. My typical approach uses bond ratings that I obtain from *AUS Utility Reports*. I also select companies with at least 50% of revenues from electric operations when estimating the return on equity for electric utility operations. However, my understanding of Opinion No. 531 is that the FERC declined to use *AUS Utility Reports* as an information source and that the Commission does not use a percentage revenue screen for selecting its group of companies.

Therefore, I did not employ these two selection criteria in this case and instead used the FERC's National Group selection criteria.

Q. What was your first step in determining the DCF return on equity for the National 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. This is also consistent with FERC's practice. The six-month period I used covered the months from April through September 2014. 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 National Group is 3.68%. These calculations are shown in Exhibit LC-4.

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.

For my analysis in this proceeding, I used two alternative formulations for estimating investor expected growth rates for the National Group. The first method uses the FERC's two-stage growth rate calculation. The first stage of this method uses the IBES 5-year growth rates obtained from Yahoo! Finance and is given two-thirds weighting in the growth calculation. The second stage uses forecasted growth in Gross Domestic Product from three different sources and is given one-third weighting in the growth calculation. FERC made quite clear in its Opinion No. 531 that this is its preferred method for estimating the investor expected growth rate in the DCF formula.

The second method I used for estimating expected growth relies on three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and IBES. This is the method I typically use for estimating growth for my DCF calculations. In my view, it is important for me to provide the FERC with the results of the method I usually employ, as it will provide valuable additional information using an alternative DCF method with other important sources of investor information.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Expanded Edition. 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 important 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 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. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

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 one can reasonably assume that they influence investor expectations.

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

A. Exhibit LC-5 presents the growth rate calculation for the National Group using the FERC's two-stage growth calculation. Column (5) presents the IBES growth rate for each company, Column (6) presents the GDP growth forecast, and Column (7) shows the two-stage weighted growth rate.

Exhibit LC-6 shows the calculation of forecasted GDP growth. Based on my understanding of the FERC's past practice I used three sources of GDP forecasts, which are the same sources used by Dr. Avera and Mr. McKenzie: IHS Global Insight, the Energy Information Administration ("EIA"), and the Social Securities Administration ("SSA") Trustees Report. I updated the GDP forecast from the SSA as its 2014 report is now available. I also used the IHS Global forecast from Dr. Avera and Mr. McKenzie's Direct Testimony, as that information is only available by purchase from IHS Global. I also used the same EIA information used by Dr. Avera and Mr. McKenzie as that is the latest information available from EIA at the time I prepared this testimony and analysis.

Exhibit LC-7 presents the Value Line, Zacks, and IBES forecasted growth estimates. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (5) of Exhibit LC-7. My method uses Value Line forecasted dividend and earning growth rates and the earnings growth forecasts from Zacks and IBES.

Q. How did you proceed to determine the DCF return of equity for the National Group?

A. To estimate the expected dividend yield (D_1), 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. The expected dividend yield for each company in the National Group is shown in Column (4) of Exhibit LC-5 and follows the FERC's usual method of presentation. The weighted growth rate is then added to the expected dividend yield for the return on equity numbers shown in Column (8).

Exhibit LC-7 presents my standard method of calculating dividend yields, growth rates, and return on equity for a group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 3.68% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the group under consideration. The calculations of the resulting DCF returns on equity for both methods are presented on page 2 of Exhibit LC-7. Please note that Zacks did not have earnings growth rate estimates for Avista Corp., Black Hills Corp., and Otter Tail Corp. For these companies I substituted the IBES growth rate based on my understanding that the FERC prefers to use the IBES consensus growth forecasts.

Q. What are the results of your two approaches to the DCF cost of equity in this proceeding?

A. The results of the FERC's two-stage approach are presented in Exhibit LC-5. I calculated the average, median, and midpoint ROE for the National Group. The average DCF result is 8.78%, the median DCF result in 9.01% and the midpoint DCF result is 9.17%.

The DCF results for my typical DCF approach are shown on page 2 of Exhibit LC-7. For the average growth rates, the results range from 8.39% to 9.23%, with the DCF ROE using the average of these results being 8.96%. Using the median growth rates, the results range from 8.26% to 8.77%, with the average of these results being 8.65%.

Q. Did you also perform FERC's two-stage DCF and your standard DCF approach to the National Group used by Dr. Avera and Mr. McKenzie?

A. Yes, I did and the results are quite similar. Exhibit LC-8 presents the results of the FERC's two-stage DCF method using the Avera/McKenzie National Group. The average DCF result is 8.88%, the median result is 9.01%, and the midpoint is 9.31%.

Exhibit LC-9 presents the results of the DCF analysis I typically employ. For the average growth rates, the results range from 8.36% to 9.27%, with the DCF ROE using the average of these results being 8.96%. Using the median growth rates, the results range from 8.23% to 9.18%, with the average of these results being 8.72%.

__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 all risks specific to a particular company and be 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.[8] There is evidence that beta is not the primary factor in determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are very limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its usefulness.

In the final analysis, 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

8 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.

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 investor-required 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 September 27, 2014. 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 as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit LC-10. I included both average and median earnings and book value growth rates and average and median dividend yields. The estimated market returns using Value Lines market data range from 10.20% to 12.74%. The average of these three market returns is 11.29%.

Q. Is this a change to how you calculated expected market return in the past?

A. Yes. In my past testimonies I simply used the average expected growth rates for earnings and book value from Value Line in calculating an expected market return. However, using three alternative formulations of expected market returns provides a more robust CAPM formulation. Further, using median growth rates is a valuable additional method of estimating the central tendency of Value Line's large data set. FERC also evaluates median growth rates in its DCF return on equity and so adding median growth rates is consistent with that approach.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2014 Classic 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 LC-11 presents the calculation of the market returns using the historical data.

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 April through September 2014. 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. 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 return on equity may be estimated.

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

A. Exhibit LC-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 8.20% using the 20-year Treasury bond and 9.61% using the five-year Treasury bond.

Utilizing the historical Ibbotson data on market returns, the market risk premium ranges from 4.80% to 6.80%. This is shown on Exhibit LC-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 National Group is .76.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are:

20-Year Treasury Bond:
3.09% + (.76 * 8.20%) = 9.33% CAPM ROE

5-Year Treasury Bond:
1.68% + (.76 * 9.61%) = 8.99% CAPM ROE

Using historical risk premiums, my CAPM results are as follows:

Geometric Mean Market Return:
3.09% + (.76 * 4.80%) = 6.75% CAPM ROE

Arithmetic Mean Market Return:
3.09% + (.76 + 6.80%) = 8.27% CAPM ROE

Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 2 below summarizes my return on equity results using the DCF and CAPM for my National Group of companies.

TABLE 2
SUMMARY OF ROE ESTIMATES

FERC Two-Stage DCF:	
- Average	8.78%
- Median	9.01%
- Midpoint	9.17%
Baudino DCF Methodology:	
Average Growth Rates	
- High	9.23%
- Low	8.39%
- Average	8.96%
Median Growth Rates:	
- High	8.77%
- Low	8.26%
- Average	8.65%
CAPM:	
- 5-Year Treasury Bond	8.99%
- 20-Year Treasury Bond	9.33%
- Historical Returns	6.75% - 8.27%

Q. What is your recommended return on equity for EAI?

A. I recommend that the FERC adopt the median 9.00% return on equity using its two-stage DCF method. I recommend that the FERC adopt the median return on equity result given the low risk nature of the capacity transactions under ESI's proposed Tariff. Given the evidence I provided earlier in my Direct Testimony, the FERC need not reach into the upper portion of the range of its two-stage DCF results in this case. Concerns about anomalous market conditions are not present today. The risks FERC described in its Opinion No. 531 regarding transmission company operations are certainly not applicable to the transactions under ESI's proposed tariff. This recommendation is also fairly consistent with the APSC's recently allowed return on equity for EAI of 9.50% in a recent base rate proceeding.

Q. Please comment on how Mr. Kollen's discussion of ESI's proposed Tariff integrates with your 9.00% return on equity recommendation.

A. Beginning on page 5 of his Direct Testimony, Mr. Kollen clearly articulates the lower risk nature of the transactions that will be subject to ESI's proposed Tariff. The fact is that the risks to the selling and purchasing Entergy Operating Companies are substantially mitigated by the virtual certainty of cost recovery both by the selling company (EAI) and by the Operating Companies that purchase that capacity. Indeed, this lower risk certainly justifies a lower required return on equity. The main risk mitigation factors as Mr. Kollen described on page 12 of his Direct Testimony are:

- A Service Agreement governs each transaction.
- The Operating Companies are wholly owned subsidiaries of Entergy Corp.
- The pricing of the transactions is based on a FERC tariff.
- Each Operating Company is virtually guaranteed cost recovery from its wholesale and retail customers.

Q. In its Opinion No. 531, the FERC chose a return on equity for the NETOs in the upper portion of the DCF range, rather than the midpoint or the median of the range. Is such a choice justified in this proceeding?

A. No. Current market conditions as well as the lower risk nature of the transactions governed by ESI's proposed Tariff do not support a move into the upper portion of the DCF range of results in this proceeding.

IV. RESPONSE TO ENTERGY TESTIMONY

Q. Have you reviewed the Direct Testimony of Dr. Avera and Mr. McKenzie?

A. Yes.

Q. Please summarize your conclusions with respect to their testimony and return on equity recommendation.

A. Dr. Avera's and Mr. McKenzie's[9] recommended 10.66% return on equity is overstated and fails to track their DCF results, which are based on the FERC's guidance in Opinion No. 531. There are two primary sources responsible for this excessive return on equity recommendation. First, their claim that anomalous market conditions warrant a higher return on equity is incorrect. Second, their choice of a return on equity in the upper portion of their DCF results is based on a misapplication of FERC's finding in Opinion No. 531, which addresses the return on equity for transmission companies.

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9 I will refer to Dr. Avera and Mr. McKenzie as "Entergy witnesses".

Q. Please address the Entergy witnesses contention regarding "anomalous" market conditions.

A. I addressed the issue of so-called anomalous market conditions in Section II of my testimony. The fact is that the economy is in a low interest rate environment that is being supported by Federal Reserve policy. Indeed, as the APSC pointed out in its Order No. 21, economic conditions change over time with periods of high and low interest rates. The Federal Reserve has supported the current low interest rate environment for several years, so it is hardly "anomalous" as the Entergy witnesses characterized it. Lower current capital costs are not consistent with the Entergy witnesses' 10.66% recommendation return on equity in this proceeding.

Q. On page 16 of the Entergy witnesses' Direct Testimony, Figure ESI-2 shows higher forecasted interest rates through 2018 from several different forecasting sources. Should the FERC increase its allowed return on equity based on these higher interest rate forecasts?

A. No. Higher interest rates have been forecasted for the last couple of years and they have not come to pass. Please refer to Table 3 below, which presents forecasted interest rates for 2014 included in Dr. Avera's Direct Testimony filed with the Florida Public Service Commission in Docket No. 120015-EI on behalf of Florida Power and Light Company ("FPL"). Dr. Avera's testimony was filed on March 19, 2012. Exhibit LC-12 provides his Exhibit WEA-2, which contains the sources of the interest rate forecasts used by Dr. Avera in that case. These interest rate forecasts were from November 25, 2011 through January 23, 2012.

TABLE 3

2014 Forecasted Interest Rates
Avera FP&L Testimony
Docket No. 120015-EI

	2014
30-Year Treasury	
- Value Line	4.5%
- IHS Global	4.5%
- Blue Chip	4.5%
AA Utility	
- IHS Global	5.6%
- EIA	5.7%

On page 29 of his Direct Testimony in Docket No. 120015-EI Dr. Avera testified that there was a "clear consensus that the cost of permanent capital will be higher in the 2012 - 2016 timeframe" and that current cost of capital estimates were conservative "because they are likely to understate investors' requirements at the time the rates set in this proceeding become effective."

Obviously, time has proven that the higher interest rate forecasts contained in Dr. Avera's FPL testimony failed to materialize. The current 30-year Treasury bond yield is approximately 3.2% and the Aa utility bond at the end of September 2014 was 4.13%, substantially lower than the forecasts presented by Dr. Avera. This points out why interest rate forecasts should not be used to justify higher (or lower) returns on equity than those based on current market conditions.

Q. Did the Entergy witnesses address the fact that FERC's Opinion No. 531 applied to transmission companies and not to power purchases between utility operating companies?

A. No. As I discussed in Section II of my Direct Testimony, the risks discussed in Opinion No. 531 for transmission companies were part of the basis the Commission relied upon to deviate from the midpoint of the DCF range of results. Those risks, which are unique to transmission companies, do not apply to the Entergy Operating companies and do not reflect the much lower risk of the capacity purchases and sales transactions between those companies. It is inappropriate for the Entergy witnesses to use a return on equity in the upper part of the DCF range for their recommended return in this proceeding.

Q. Did the Entergy witnesses use other return on equity models in support of their recommendation of 10.66%?

A. Yes. The Entergy witnesses used risk premium analysis based on Commission-allowed ROEs, forward-looking CAPM analyses, and expected earned returns for the electric industry. These alternative analyses have serious flaws and, as such, cannot be relied upon by the FERC for its allowed return on equity in this proceeding. I will address each of these analyses in the following sections of my testimony.

<u>Risk Premium</u>

Q. Please summarize the Entergy witnesses' risk premium approach.

A. The Entergy witnesses developed an historical risk premium using FERC-allowed returns for regulated utility companies since 2006. They also used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. On page 36 of their Direct Testimony, the Entergy witnesses calculated the risk premium return on equity to be 10.62%.

Q. Please respond to the Entergy witnesses' risk premium analysis.

A. Generally, 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 and with varying risk perceptions of investors. 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 an historical risk premium analysis over a certain period of time. In addition, there is a high degree of circularity in using FERC-allowed returns to estimate the return on equity in this case. The Entergy witnesses' study assumes that this Commission should base its ROE determination on what it has decided since

2006. I do not agree with this implied assumption and I recommend that the Commission rely upon valid current market evidence presented in this proceeding to support its ROE decision.

Capital Asset Pricing Model

Q. Please present your conclusions regarding the results of the Entergy witnesses' CAPM analysis.

A. I disagree with the Entergy witnesses' formulation of the CAPM and in particular with their estimate of the expected market return. They estimated the market return portion of the CAPM by estimating the current market return for dividend paying stocks in the S&P 500. This limited so-called "market" return to only 410 companies.

The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks. In practice, of course, finding such an estimate is difficult and is one of the more thorny problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of 2,352 stocks and its book value growth estimate used 1,548 stocks. These are much broader samples than the Entergy witnesses' limited sample of dividend paying stocks from the S&P 500.

Q. **On pages 39 through 40 of their Direct Testimony, the Entergy witnesses explained that they incorporated a size adjustment to their CAPM results, thereby increasing the median CAPM cost of equity from 10.1% to 11.35%. Is this size adjustment appropriate?**

A. No. The data that the Entergy witnesses relied upon to make this adjustment came from the *Ibbotson SBBI 2014 Classic Yearbook* published by Morningstar. The groups of companies from which the Entergy witnesses took this significant upward adjustment to their CAPM results contains many unregulated companies. Further, decile groups from which these adjustments were taken had average betas ranging from 0.91 to 1.30. These betas are greatly in excess of the National Group beta of 0.75, suggesting that the companies the Entergy witnesses used to make their size adjustment are more risky than the regulated utilities that comprise the National Group. There is no evidence to suggest that the size premium used by the Entergy witnesses applies to regulated utility companies, which on average are quite different from the group of companies included in the Morningstar research on size premiums. I recommend that the Commission reject the Entergy witnesses' size premium in the CAPM ROE.

Expected Earnings Approach

Q. Beginning on page 40 of their Direct Testimony, the Entergy witnesses presented an expected earnings approach based on expected returns on equity using Value Line's rates of return on common equity for electric utilities over its 2017 - 2019 forecast horizon. Is this a reasonable method for estimating the current required return on equity in this proceeding?

A. No. The FERC should not rely on forecasted utility ROEs for 2017 - 2019 for the same reasons that it should not rely on interest rate forecasts. These forecasts return on equity have little value in today's market, especially considering that current DCF returns are significantly lower than these forecast. Once again, I recommend that the FERC rely on current market data as the best measure of investor required returns today.

In addition, the Entergy witnesses actually inflated the Value Line ROE forecasts by using an adjustment factor based on the expected increases in common equity from 2013 to 2018. This is completely inappropriate and should be rejected by the Commission. Simply using the Value Line forecasted ROEs in Column (a) of Exhibit ESI-107 results in an average forecasted ROE of 9.7% and a median value of 9.5%. These numbers are quite close to my ROE recommendation of 9.00%. I present these calculations in Exhibit LC-13.

Other ROE Methods

Q. On page 45 of their Direct Testimony, the Entergy witnesses presented results of a risk premium analysis using state-allowed ROEs. Please comment on this analysis.

A. My objection to this type of analysis is similar to the objection I had to the analysis using FERC-allowed ROEs. Essentially, this analysis suggests that the FERC base its allowed ROE on what state regulatory have allowed in the past. Further, the most recent state-allowed ROE for EAI was 9.50%, significantly less than the 10.13% result for the Entergy witnesses' risk premium model.

Q. On page 46 of their Direct Testimony, the Entergy witnesses describe the ECAPM analysis. Is this a reasonable method to use to estimate the investor required ROE for the Entergy Operating companies?

A. No. The ECAPM is supposed to account for the possibility that the CAPM understates the return on equity for companies with betas less than 1.0. I believe it is highly unlikely that investors use the ECAPM formulation shown in ESI-109 to "correct" CAPM returns for electric utilities. To the extent investors use the CAPM to estimate their required returns, I believe it is much more likely that they use the traditional CAPM equation that I used in Section III of my testimony. The Entergy witnesses presented no evidence that investors use the adjustment factors contained their ECAPM analyses. Moreover, the use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas by such sources as Value Line are incorrect and that investors should not rely on them. In fact, the Entergy witnesses testified on page 38, lines 25 through 26 that investors rely on Value Line betas in evaluating returns for utility common stocks.

Q. Beginning on page 47 of their Direct Testimony, the Entergy witnesses present a return of equity analysis using gas pipeline returns on equity. Is this analysis a valid one for the FERC's consideration in this proceeding?

A. It certainly is not. The FERC declined to compare electric utilities to natural gas pipelines in its Opinion No. 531 and this decision is still the appropriate one in this case. This is especially true considering that the FERC was setting the allowed ROE for a group of electric transmission companies. Lower risk capacity sales and purchases between Entergy's operating companies bear no resemblance whatsoever to the operations and attendant risks of natural gas pipelines. Although the Entergy witnesses tried to adjust for the higher allowed FERC ROEs for natural gas pipelines, this entire analysis simply is not applicable to the issue in this case. The FERC should continue to reject ROE analyses that use natural gas pipeline ROEs.

Q. Beginning on page 49 of their Direct Testimony, the Entergy witnesses recommended using projected bond yields in their risk premium and CAPM ROE models. Should the FERC consider using forecasted bond yields in its ROE analysis in this proceeding?

A. Definitely not. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yields used by the Entergy witnesses are speculative at best and may never come to pass. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates and bond yields 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. Beginning of page 51 of their Direct Testimony, the Entergy witnesses present the results of a low-risk non-utility DCF model. Is it appropriate to use a group of unregulated companies to estimate a fair return on equity for the Entergy Operating companies?

A. Absolutely not. The Entergy witnesses' use of unregulated non-utility companies to estimate a fair rate of return for the Entergy Operating companies is completely inappropriate and should be rejected by the Commission.

Utilities have protected markets, e.g. service territories, and may increase the prices they charge in the face of falling demand or loss of customers. This is contrary to competitive, unregulated companies who often lower their prices when demand for their products decline. Generally, the non-utility companies simply do not have these characteristics and must compete with other firms selling the same product for sales and for customers. Obviously, the non-utility companies have higher overall risk structures than a lower risk electric company like Entergy and will have higher required returns from their shareholders. It is not at all surprising that the Entergy witnesses' ROE results for his Non-Utility Proxy Group were substantially higher than the results for their National Group. Given the higher business risk for the non-utility group of companies, this is exactly the result that would have been expected. However, these results do not form any kind of reasonable basis to estimate the investor required ROE for the Entergy Operating companies. Quite the contrary, the returns from the non-utility proxy group are a good measure of returns that are, by definition, substantially in excess of those to be expected in the utility segment.

Flotation Costs

Q. Beginning on page 56 of their Direct Testimony, the Entergy witnesses discuss flotation costs. Are flotation costs a legitimate consideration for the Commission's determination of ROE in this proceeding?

A. No. The Entergy witnesses recommended that the FERC consider adding an adjustment of 14 to 40 basis to recognize flotation costs, although they did not explicitly add such an adjustment to their recommended return on equity in this proceeding. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as well as broker fees and discounts.

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.

Further, the Entergy witnesses did not provide any information regarding actual flotation costs incurred by Entergy, Inc. or whether Entergy is considering issuing common stock in the future. Value Line's most recent report for Entergy, Inc. shows no new shares being issued by the Company through the 2017 - 2019 forecast period, so there would be no flotation costs being incurred during the next few years.

Q. Does this complete your Direct Testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Sworn to and subscribed before me on this
9th day of October 2014.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc. *al.*	)	**Docket Nos. ER13-1508-001 *et***
	)	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 9, 2014

1171287v2

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-2

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group

Expert Testimony Appearances
of
Richard A. Baudino
As of October 2014

Date	Case	Jurisdict.	Party	Utility	Subject

Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance

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Date	Case	Jurisdict.	Party	Utility	Subject
3/83	1780	NM	New Mexico Public Service Commission	Boles Water Co.	Rate design, rate of return.
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design.
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public	Central Louisiana	Return on equity,

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Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission	Electric Co.	rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc.	PGE Industrial Intervenors	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips	T. W. Phillips	Allocation of purchased

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Date	Case	Jurisdict.	Party	Utility	Subject
			Users Group	Gas and Oil Co.	gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Comm.	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Stranded cost analysis.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.
11/01	U-25687	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity

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of
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As of October 2014

Date	Case	Jurisdict.	Party	Utility	Subject
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112		AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661		Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01		Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103		Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797		Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Elec. Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR		Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589,	IL	The Commercial Group	Ameren	Cost allocation, rate design

**Expert Testimony Appearances
of
Richard A. Baudino
As of October 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
	07-0590, (consol.)				
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy users Group	PECO Energy	Cost and revenue allocation, Tariff issues
07/08	R-2008-2039634	PA	PPL Gas Large Users Gp.	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065		The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532		The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI		South Florida Hospital and Health Care Assn.	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana PSC	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design

Expert Testimony Appearances
of
Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation

Expert Testimony Appearances
of
Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Gp. Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation
03/10	09-1352-E-42T	WV	West Virginia Energy Users Gp.	Monongahela Power, Potomac Edison	Return on equity, rate of return
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Compay	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Gp.	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Svc. Of Colorado	Return on equity, wtd. cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Assn.	Florida Power and Light Co,	Return on equity, wtd. cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pannsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility		

Expert Testimony Appearances
of
Richard A. Baudino
As of October 2014

Date	Case	Jurisdict.	Party	Utility	Subject
			Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Gp.	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity

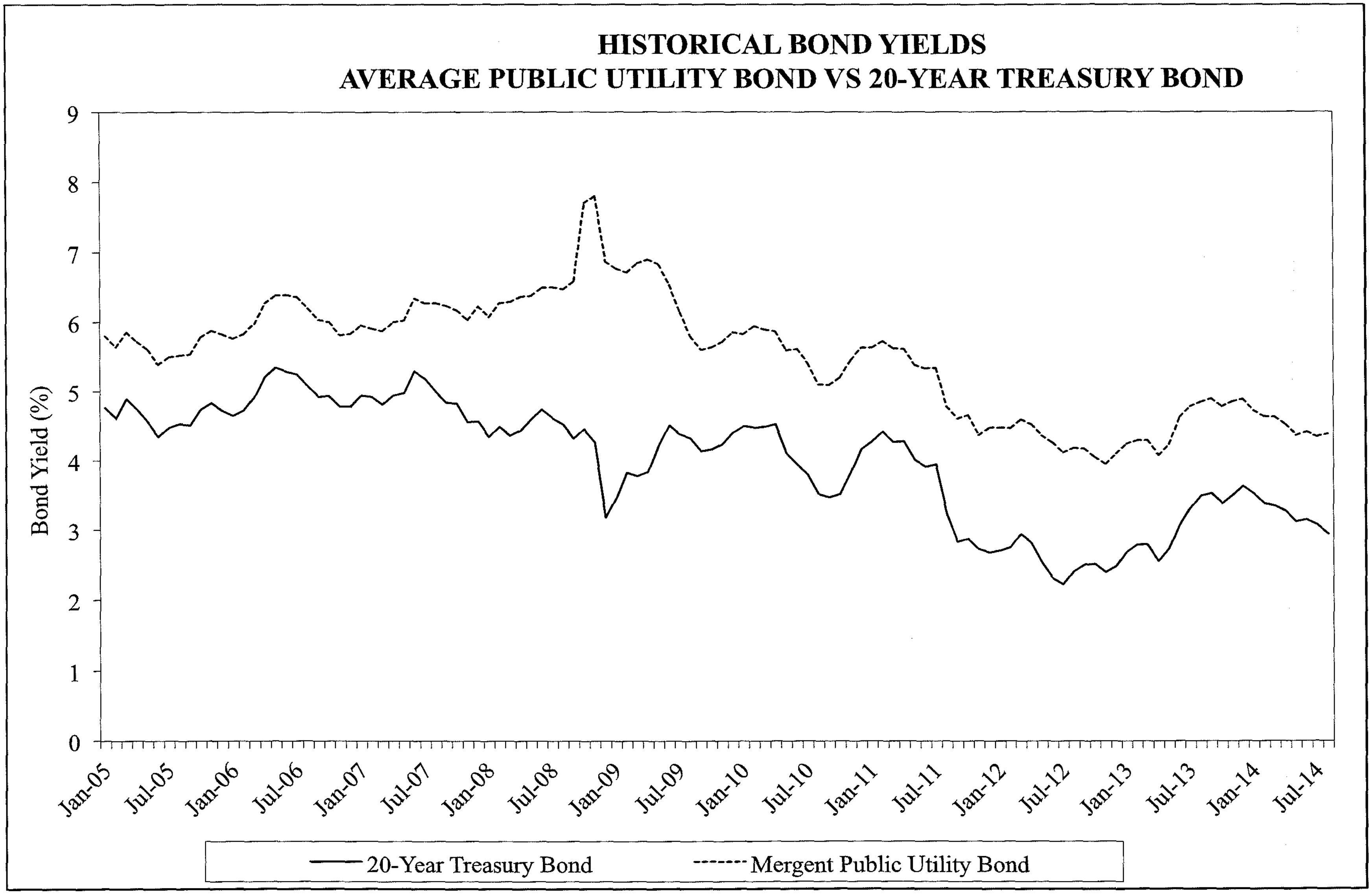
UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-3


HISTORICAL BOND YIELDS
AVERAGE PUBLIC UTILITY BOND VS 20-YEAR TREASURY BOND
Bond Yield (%)
9
8
7
6
5
4
3
2
1
0
Jan-05
Jul-05
Jan-06
Jul-06
Jan-07
Jul-07
Jan-08
Jul-08
Jan-09
Jul-09
Jan-10
Jul-10
Jan-11
Jul-11
Jan-12
Jul-12
Jan-13
Jul-13
Jan-14
Jul-14
20-Year Treasury Bond
Mergent Public Utility Bond

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	Docket Nos. ER13-1508-001 *et al.*
	)	

EXHIBIT LC-4

NATIONAL GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-14	Aug-14	Jul-14	Jun-14	May-14	Apr-14
Ameren Corp.	High Price ($)	40.310	39.990	40.960	40.990	41.620	41.920
	Low Price ($)	37.530	36.650	38.440	37.670	37.940	39.410
	Avg. Price ($)	38.920	38.320	39.700	39.330	39.780	40.665
	Dividend ($)	0.400	0.400	0.400	0.400	0.400	0.400
	Mo. Avg. Div.	4.11%	4.18%	4.03%	4.07%	4.02%	3.93%
	6 mos. Avg.	4.06%					
American Electric Power	High Price ($)	53.880	53.710	55.910	55.940	54.060	54.640
	Low Price ($)	51.580	49.060	51.960	51.600	50.820	49.990
	Avg. Price ($)	52.730	51.385	53.935	53.770	52.440	52.315
	Dividend ($)	0.500	0.500	0.500	0.500	0.500	0.500
	Mo. Avg. Div.	3.79%	3.89%	3.71%	3.72%	3.81%	3.82%
	6 mos. Avg.	3.79%					
Avista Corp.	High Price ($)	32.880	32.470	33.600	33.580	32.940	32.370
	Low Price ($)	30.450	30.350	31.020	30.380	30.900	30.020
	Avg. Price ($)	31.665	31.410	32.310	31.980	31.920	31.195
	Dividend ($)	0.318	0.318	0.318	0.318	0.318	0.318
	Mo. Avg. Div.	4.02%	4.05%	3.94%	3.98%	3.98%	4.08%
	6 mos. Avg.	4.01%					
Black Hills Corp.	High Price ($)	54.050	53.890	62.130	61.410	60.380	59.080
	Low Price ($)	47.870	50.390	52.700	57.020	55.230	56.460
	Avg. Price ($)	50.960	52.140	57.415	59.215	57.805	57.770
	Dividend ($)	0.390	0.390	0.390	0.390	0.390	0.390
	Mo. Avg. Div.	3.06%	2.99%	2.72%	2.63%	2.70%	2.70%
	6 mos. Avg.	2.80%					
Cleco Corp.	High Price ($)	58.230	56.550	59.210	59.130	53.060	52.620
	Low Price ($)	48.060	53.670	54.650	50.740	50.330	49.320
	Avg. Price ($)	53.145	55.110	56.930	54.935	51.695	50.970
	Dividend ($)	0.400	0.400	0.400	0.400	0.400	0.363
	Mo. Avg. Div.	3.01%	2.90%	2.81%	2.91%	3.10%	2.85%
	6 mos. Avg.	2.93%					
CMS Energy	High Price ($)	30.830	30.540	31.200	31.230	30.430	30.530
	Low Price ($)	29.150	27.900	28.870	28.970	28.700	28.930
	Avg. Price ($)	29.990	29.220	30.035	30.100	29.565	29.730
	Dividend ($)	0.270	0.270	0.270	0.270	0.270	0.270
	Mo. Avg. Div.	3.60%	3.70%	3.60%	3.59%	3.65%	3.63%
	6 mos. Avg.	3.63%					
El Paso Electric	High Price ($)	39.410	39.420	40.430	40.330	38.420	38.250
	Low Price ($)	36.050	35.390	36.810	36.670	35.210	35.440
	Avg. Price ($)	37.730	37.405	38.620	38.500	36.815	36.845
	Dividend ($)	0.280	0.280	0.280	0.280	0.265	0.265
	Mo. Avg. Div.	2.97%	2.99%	2.90%	2.91%	2.88%	2.88%
	6 mos. Avg.	2.92%					

NATIONAL GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-14	Aug-14	Jul-14	Jun-14	May-14	Apr-14
Empire District Elec.	High Price ($)	25.950	26.000	25.870	25.710	24.420	24.860
	Low Price ($)	24.000	24.020	24.360	23.560	23.230	23.770
	Avg. Price ($)	24.975	25.010	25.115	24.635	23.825	24.315
	Dividend ($)	0.255	0.255	0.255	0.255	0.255	0.255
	Mo. Avg. Div.	4.08%	4.08%	4.06%	4.14%	4.28%	4.19%
	6 mos. Avg.	4.14%					
Entergy Corp.	High Price ($)	78.370	77.450	82.480	82.300	75.690	73.920
	Low Price ($)	75.290	70.700	72.810	75.420	71.680	66.410
	Avg. Price ($)	76.830	74.075	77.645	78.860	73.685	70.165
	Dividend ($)	0.830	0.830	0.830	0.830	0.830	0.830
	Mo. Avg. Div.	4.32%	4.48%	4.28%	4.21%	4.51%	4.73%
	6 mos. Avg.	4.42%					
Great Plains Energy	High Price ($)	25.800	25.910	26.950	27.050	27.280	27.520
	Low Price ($)	23.910	24.090	24.710	24.720	24.970	26.190
	Avg. Price ($)	24.855	25.000	25.830	25.885	26.125	26.855
	Dividend ($)	0.230	0.230	0.230	0.230	0.230	0.230
	Mo. Avg. Div.	3.70%	3.68%	3.56%	3.55%	3.52%	3.43%
	6 mos. Avg.	3.57%					
Hawaiian Electric	High Price ($)	26.890	25.410	25.380	25.650	24.400	25.390
	Low Price ($)	24.910	22.710	23.440	23.630	23.040	23.460
	Avg. Price ($)	25.900	24.060	24.410	24.640	23.720	24.425
	Dividend ($)	0.310	0.310	0.310	0.310	0.310	0.310
	Mo. Avg. Div.	4.79%	5.15%	5.08%	5.03%	5.23%	5.08%
	6 mos. Avg.	5.06%					
IDACORP	High Price ($)	56.970	56.800	58.790	57.860	56.370	56.490
	Low Price ($)	53.200	51.700	53.550	53.780	52.910	54.250
	Avg. Price ($)	55.085	54.250	56.170	55.820	54.640	55.370
	Dividend ($)	0.430	0.430	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	3.12%	3.17%	3.06%	3.08%	3.15%	3.11%
	6 mos. Avg.	3.12%					
Otter Tail Corp.	High Price ($)	28.700	28.910	30.430	30.300	29.520	31.080
	Low Price ($)	26.670	27.160	27.900	28.260	27.190	28.950
	Avg. Price ($)	27.685	28.035	29.165	29.280	28.355	30.015
	Dividend ($)	0.303	0.303	0.303	0.303	0.303	0.303
	Mo. Avg. Div.	4.38%	4.32%	4.16%	4.14%	4.27%	4.04%
	6 mos. Avg.	4.22%					

NATIONAL GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-14	Aug-14	Jul-14	Jun-14	May-14	Apr-14
PG&E Corp.	High Price ($)	48.240	46.480	48.090	48.640	45.990	46.110
	Low Price ($)	43.760	42.920	44.650	45.270	42.850	42.300
	Avg. Price ($)	46.000	44.700	46.370	46.955	44.420	44.205
	Dividend ($)	0.455	0.455	0.455	0.455	0.455	0.455
	Mo. Avg. Div.	3.96%	4.07%	3.92%	3.88%	4.10%	4.12%
	6 mos. Avg.	4.01%					
PNM Resources	High Price ($)	26.970	26.250	29.940	29.330	29.220	28.500
	Low Price ($)	24.760	24.260	25.640	27.600	26.190	26.700
	Avg. Price ($)	25.865	25.255	27.790	28.465	27.705	27.600
	Dividend ($)	0.185	0.185	0.185	0.185	0.185	0.185
	Mo. Avg. Div.	2.86%	2.93%	2.66%	2.60%	2.67%	2.68%
	6 mos. Avg.	2.73%					
Public Service Ent. Gp.	High Price ($)	38.320	37.410	40.680	40.930	41.350	41.380
	Low Price ($)	36.040	34.050	35.110	37.060	36.910	37.340
	Avg. Price ($)	37.180	35.730	37.895	38.995	39.130	39.360
	Dividend ($)	0.370	0.370	0.370	0.370	0.370	0.370
	Mo. Avg. Div.	3.98%	4.14%	3.91%	3.80%	3.78%	3.76%
	6 mos. Avg.	3.89%					
SCANA Corp.	High Price ($)	52.230	51.940	53.890	53.880	53.830	53.710
	Low Price ($)	48.810	48.530	50.780	49.510	50.440	50.350
	Avg. Price ($)	50.520	50.235	52.335	51.695	52.135	52.030
	Dividend ($)	0.525	0.525	0.525	0.525	0.525	0.525
	Mo. Avg. Div.	4.16%	4.18%	4.01%	4.06%	4.03%	4.04%
	6 mos. Avg.	4.08%					
Sempra Energy	High Price ($)	107.810	106.090	104.600	105.250	100.690	99.810
	Low Price ($)	102.340	96.130	99.600	98.320	96.580	95.150
	Avg. Price ($)	105.075	101.110	102.100	101.785	98.635	97.480
	Dividend ($)	0.660	0.660	0.660	0.660	0.660	0.660
	Mo. Avg. Div.	2.51%	2.61%	2.59%	2.59%	2.68%	2.71%
	6 mos. Avg.	2.61%					
Westar Energy	High Price ($)	37.070	37.090	38.230	38.240	36.100	36.350
	Low Price ($)	33.760	34.530	36.040	35.220	34.720	34.510
	Avg. Price ($)	35.415	35.810	37.135	36.730	35.410	35.430
	Dividend ($)	0.350	0.350	0.350	0.350	0.350	0.350
	Mo. Avg. Div.	3.95%	3.91%	3.77%	3.81%	3.95%	3.95%
	6 mos. Avg.	3.89%					
Average Dividend Yield		3.68%					

Source: Yahoo! Finance

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	Docket Nos. ER13-1508-001 *et al.*

EXHIBIT LC-5

NATIONAL GROUP
DCF RETURN ON EQUITY WITH FERC TWO-STAGE GROWTH

(1)	(2) Dividend Yield	(3) Adjustment	(4) Expected Div. Yield	(5) IBES Growth	(6) GDP Growth	(7) FERC Weighted Growth	(8) ROE	
Ameren Corp.	4.06%	1.037	4.21%	8.90%	4.36%	7.39%	11.59%	
American Elec Pwr	3.79%	1.023	3.88%	4.79%	4.36%	4.65%	8.53%	
Avista Corp.	4.01%	1.024	4.10%	5.00%	4.36%	4.79%	8.89%	
Black Hills Corp.	2.80%	1.031	2.89%	7.00%	4.36%	6.12%	9.01%	
Cleco Corp.	2.93%	1.031	3.02%	7.00%	4.36%	6.12%	9.14%	
CMS Energy Corp.	3.63%	1.030	3.74%	6.80%	4.36%	5.99%	9.72%	
El Paso Electric	2.92%	1.031	3.01%	7.00%	4.36%	6.12%	9.13%	
Empire District Elec	4.14%	1.017	4.21%	3.00%	4.36%	3.45%	7.67%	
Entergy Corp.	4.42%	1.012	4.47%	1.33%	4.36%	2.34%	6.81%	
Great Plains Energy	3.57%	1.024	3.66%	5.00%	4.36%	4.79%	8.45%	
Hawaiian Elec.	5.06%	1.021	5.16%	4.00%	4.36%	4.12%	9.29%	
IDACORP, Inc.	3.12%	1.021	3.18%	4.00%	4.36%	4.12%	7.30%	
Otter Tail Corp.	4.22%	1.027	4.33%	6.00%	4.36%	5.45%	9.79%	
PG&E Corp.	4.01%	1.030	4.13%	6.95%	4.36%	6.09%	10.22%	
PNM Resources	2.73%	1.035	2.83%	8.32%	4.36%	7.00%	9.83%	
Pub Sv Enterprise Gı	3.89%	1.014	3.95%	2.00%	4.36%	2.79%	6.74%	
SCANA Corp.	4.08%	1.023	4.17%	4.60%	4.36%	4.52%	8.69%	
Sempra Energy	2.61%	1.032	2.70%	7.38%	4.36%	6.37%	9.07%	
Westar Energy	3.89%	1.015	3.95%	2.40%	4.36%	3.05%	7.01%	
Averages	3.68%		3.77%	5.34%	4.36%	5.01%	8.78%	
Median							9.01%	
Range of ROE Values						6.74%	-	11.59%
Midpoint of ROE range							9.17%	

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-6

FERC GDP GROWTH RATE

		2020	2040	2044	2070	
IHS Global Insight						4.30%
Energy Information Administration						
	Real GDP	16,753	26,670			
	GDP Deflato	1.307	1.913			
		21,896	51,020			4.32%
SSA Trustees Report		23,694			211,004	4.47%
Average GDP Growth Rate						4.36%

Sources:
IHS Global Insight growth rate from Exhibit ES!-104, page 2 of 2
Energy Information Administration, *Annual Energy Outlook 2014* (May 7, 2014).
Social Security Administration, 2014 OASDI Trustees Report,
Table VI.G6 - Selected Economic Variables, Calendar Years 2013-90

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-7

NATIONAL GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
Ameren Corp.	2.00%	4.50%	4.00%	8.30%	8.90%
American Elec Pwr	4.50%	4.50%	4.00%	4.80%	4.79%
Avista Corp.	4.50%	5.50%	3.00%	5.00%	5.00%
Black Hills Corp.	4.00%	9.50%	4.00%	7.00%	7.00%
Cleco Corp.	8.00%	3.50%	4.00%	8.00%	7.00%
CMS Energy Corp.	6.00%	6.50%	6.00%	6.10%	6.80%
El Paso Electric	7.00%	3.00%	5.00%	3.50%	7.00%
Empire District Elec	4.50%	4.00%	3.50%	3.00%	3.00%
Entergy Corp.	2.50%	1.00%	4.00%	-1.00%	1.33%
Great Plains Energy	6.00%	6.00%	3.00%	5.00%	5.00%
Hawaiian Elec.	1.00%	4.00%	3.50%	4.00%	4.00%
IDACORP, Inc.	6.50%	1.00%	3.50%	4.00%	4.00%
Otter Tail Corp.	1.50%	15.50%	5.00%	6.00%	6.00%
PG&E Corp.	2.50%	5.00%	2.50%	5.60%	6.95%
PNM Resources	12.00%	11.00%	5.00%	8.50%	8.32%
Pub Sv Enterprise Grp	2.50%	2.00%	5.00%	2.10%	2.00%
SCANA Corp.	3.00%	5.00%	4.50%	4.40%	4.60%
Sempra Energy	7.00%	6.00%	5.50%	7.00%	7.38%
Westar Energy	3.00%	6.00%	4.50%	3.70%	2.40%
Averages excluding negative values	4.63%	5.45%	4.18%	5.33%	5.34%
Median Values	4.50%	5.00%	4.00%	5.00%	5.00%

Sources: Value Line Investment Survey, August 1, August 22, and September 19, 2014
Yahoo! Finance for IBES growth rates retrieved September 22, 2014
Zacks growth rates retrieved September 22, 2014
IBES growth rates were used in the Zacks column for Avista, Black Hills, and Otter Tail.

NATIONAL GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.68%	3.68%	3.68%	3.68%	3.68%
Average Growth Rate	4.63%	5.45%	5.33%	5.34%	5.19%
Expected Div. Yield	3.76%	3.78%	3.78%	3.78%	3.77%
DCF Return on Equity	***8.39%***	***9.23%***	***9.11%***	***9.12%***	***8.96%***
Method 2:					
Dividend Yield	3.68%	3.68%	3.68%	3.68%	3.68%
Median Growth Rate	4.50%	5.00%	5.00%	5.00%	4.88%
Expected Div. Yield	3.76%	3.77%	3.77%	3.77%	3.77%
DCF Return on Equity	***8.26%***	***8.77%***	***8.77%***	***8.77%***	***8.65%***

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

EXHIBIT LC-8

AVERA/MCKENZIE NATIONAL GROUP
DCF RETURN ON EQUITY WITH FERC TWO-STAGE GROWTH

(1)	(2) Dividend Yield	(3) Adjustment	(4) Expected Div. Yield	(5) IBES Growth	(6) GDP Growth	(7) FERC Weighted Growth	(8) ROE	
ALLETE	4.00%	1.027	4.11%	6.00%	4.36%	5.45%	9.56%	
Ameren Corp.	4.06%	1.037	4.21%	8.90%	4.36%	7.39%	11.59%	
American Elec Pwr	3.79%	1.023	3.88%	4.79%	4.36%	4.65%	8.53%	
Avista Corp.	4.01%	1.024	4.10%	5.00%	4.36%	4.79%	8.89%	
Black Hills Corp.	2.80%	1.031	2.89%	7.00%	4.36%	6.12%	9.01%	
Cleco Corp.	2.93%	1.031	3.02%	7.00%	4.36%	6.12%	9.14%	
CMS Energy Corp.	3.63%	1.030	3.74%	6.80%	4.36%	5.99%	9.72%	
DTE Energy Co.	3.48%	1.027	3.57%	5.85%	4.36%	5.35%	8.93%	
Duke Energy Corp.	4.33%	1.023	4.43%	4.70%	4.36%	4.59%	9.02%	
Edison International	2.52%	1.019	2.57%	3.49%	4.36%	3.78%	6.35%	
El Paso Electric	2.92%	1.031	3.01%	7.00%	4.36%	6.12%	9.13%	
Empire District Elec	4.14%	1.017	4.21%	3.00%	4.36%	3.45%	7.67%	
Entergy Corp.	4.42%	1.012	4.47%	1.33%	4.36%	2.34%	6.81%	
Great Plains Energy	3.57%	1.024	3.66%	5.00%	4.36%	4.79%	8.45%	
Hawaiian Elec.	5.06%	1.021	5.16%	4.00%	4.36%	4.12%	9.29%	
IDACORP, Inc.	3.12%	1.021	3.18%	4.00%	4.36%	4.12%	7.30%	
Otter Tail Corp.	4.22%	1.027	4.33%	6.00%	4.36%	5.45%	9.79%	
PG&E Corp.	4.01%	1.030	4.13%	6.95%	4.36%	6.09%	10.22%	
PNM Resources	2.73%	1.035	2.83%	8.32%	4.36%	7.00%	9.83%	
Portland General Ele	3.36%	1.044	3.51%	10.96%	4.36%	8.76%	12.27%	
Pub Sv Enterprise Gı	3.89%	1.014	3.95%	2.00%	4.36%	2.79%	6.74%	
SCANA Corp.	4.08%	1.023	4.17%	4.60%	4.36%	4.52%	8.69%	
Sempra Energy	2.61%	1.032	2.70%	7.38%	4.36%	6.37%	9.07%	
Westar Energy	3.89%	1.015	3.95%	2.40%	4.36%	3.05%	7.01%	
Averages	3.65%		3.74%	5.52%	4.36%	5.13%	8.88%	
Median							9.01%	
Range of ROE Values						6.35%	-	12.27%
Midpoint of ROE range							9.31%	

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-9

AVERA MCKENZIE NATIONAL GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
ALLETE	4.00%	6.00%	3.50%	6.00%	6.00%
Ameren Corp.	2.00%	4.50%	4.00%	8.30%	8.90%
American Elec Pwr	4.50%	4.50%	4.00%	4.80%	4.79%
Avista Corp.	4.50%	5.50%	3.00%	5.00%	5.00%
Black Hills Corp.	4.00%	9.50%	4.00%	7.00%	7.00%
Cleco Corp.	8.00%	3.50%	4.00%	8.00%	7.00%
CMS Energy Corp.	6.00%	6.50%	6.00%	6.10%	6.80%
DTE Energy Co.	5.00%	6.50%	4.00%	6.20%	5.85%
Duke Energy Corp.	2.00%	5.00%	3.00%	4.30%	4.70%
Edison International	7.50%	2.50%	6.00%	3.40%	3.49%
El Paso Electric	7.00%	3.00%	5.00%	3.50%	7.00%
Empire District Elec	4.50%	4.00%	3.50%	3.00%	3.00%
Entergy Corp.	2.50%	1.00%	4.00%	-1.00%	1.33%
Great Plains Energy	6.00%	6.00%	3.00%	5.00%	5.00%
Hawaiian Elec.	1.00%	4.00%	3.50%	4.00%	4.00%
IDACORP, Inc.	6.50%	1.00%	3.50%	4.00%	4.00%
Otter Tail Corp.	1.50%	15.50%	5.00%	6.00%	6.00%
PG&E Corp.	2.50%	5.00%	2.50%	5.60%	6.95%
PNM Resources	12.00%	11.00%	5.00%	8.50%	8.32%
Portland General Elec.	4.50%	5.00%	4.00%	7.80%	10.96%
Pub Sv Enterprise Grp	2.50%	2.00%	5.00%	2.10%	2.00%
SCANA Corp.	3.00%	5.00%	4.50%	4.40%	4.60%
Sempra Energy	7.00%	6.00%	5.50%	7.00%	7.38%
Westar Energy	3.00%	6.00%	4.50%	3.70%	2.40%
Averages excluding negative values	4.63%	5.35%	4.17%	5.38%	5.52%
Median Values	4.50%	5.00%	4.00%	5.00%	5.43%

Sources: Value Line Investment Survey, August 1, August 22, and September 19, 2014
Yahoo! Finance for IBES growth rates retrieved September 22, 2014
Zacks growth rates retrieved September 22, 2014
IBES growth rates were used in the Zacks column for ALLETE, Avista, Black Hills, and Otter Tail.

AVERA/MCKENZIE NATIONAL GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.65%	3.65%	3.65%	3.65%	3.65%
Average Growth Rate	4.63%	5.35%	5.38%	5.52%	5.22%
Expected Div. Yield	3.73%	3.75%	3.75%	3.75%	3.74%
DCF Return on Equity	8.36%	9.10%	9.13%	9.27%	8.96%
Method 2:					
Dividend Yield	3.65%	3.65%	3.65%	3.65%	3.65%
Median Growth Rate	4.50%	5.00%	5.00%	5.43%	4.98%
Expected Div. Yield	3.73%	3.74%	3.74%	3.75%	3.74%
DCF Return on Equity	8.23%	8.74%	8.74%	9.18%	8.72%

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

EXHIBIT LC-10

NATIONAL GROUP
Capital Asset Pricing Model Analysis
20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.29%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	3.09%
4	Risk Premium	
5	@ 6 Month Average RFR (Line 4 minus Line 6)	8.20%
6	National Group Beta	0.76
7	National Group Beta * Risk Premium	
8	@ 6 Month Average RFR (Line 10 * Line 9)	6.24%
9	CAPM Return on Equity	
10	@ 6 Month Average RFR (Line 12 plus Line 6)	9.33%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.29%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.68%
4	Risk Premium	
5	@ 6 Month Average RFR (Line 4 minus Line 6)	9.61%
6	National Group Beta	0.76
7	National Group Beta * Risk Premium	
8	@ 6 Month Average RFR (Line 9 * Line 10)	7.32%
9	CAPM Return on Equity	
10	@ 6 Month Average RFR (Line 12 plus Line 6)	8.99%

NATIONAL GROUP
Capital Asset Pricing Model Analysis
Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
April-14	3.27%
May-14	3.12%
June-14	3.15%
July-14	3.07%
August-14	2.94%
September-14	3.01%
6 month average	3.09%

5 Year Treasury Bond Data

	Avg. Yield
April-14	1.70%
May-14	1.59%
June-14	1.68%
July-14	1.70%
August-14	1.63%
September-14	1.77%
6 month average	1.68%

Value Line Market Growth Rate Data:

Forecasted Data:

Value Line Average Growth Rates:	
Earnings	14.09%
Book Value	9.85%
Average	11.97%
Average Dividend Yield	0.77%
Estimated Market Return	12.74%
Value Line Median Growth Rates:	
Earnings	12.00%
Book Value	9.85%
Average	10.93%
Median Dividend Yield	0.00%
Estimated Market Return	10.93%
Value Line Projected 3-5 Yr. Annual Total Return	10.20%
Average of Projected Mkt. Returns	11.29%

Source: Value Line Investment Survey for Windows retreived September 27, 2014

National Group Betas:	Value Line
Ameren Corp.	0.75
American Elec Pwr	0.70
Avista Corp.	0.75
Black Hills Corp.	0.85
Cleco Corp.	0.75
El Paso Electric	0.70
Empire District Elec	0.65
Entergy Corp.	0.70
Great Plains Energy	0.85
Hawaiian Elec.	0.75
IDACORP, Inc.	0.80
Otter Tail Corp.	0.95
PG&E Corp.	0.65
PNM Resources	0.85
Pub Sv Enterprise Grp	0.75
SCANA Corp.	0.75
Sempra Energy	0.75
Westar Energy	0.75
Average	0.76

Source: Value Line Investment Survey

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-11

NATIONAL GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%
Long-Term Annual Income Return on Long-Term Government Bor	5.30%	5.30%
Historical Market Risk Premium	4.80%	6.80%
National Group Beta, Value Line	0.76	0.76
Beta * Market Premium	3.65%	5.18%
Current 20-Year Treasury Bond Yield	3.09%	3.09%
CAPM Cost of Equity, Value Line Beta	**6.75%**	**8.27%**

Source: *Ibbotson SBBI 2014 Classic Yearbook,* Morningstar, pp. 39 - 40.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

EXHIBIT LC-12

Docket No. 120015-EI
Interest Rate Trends
Exhibit WEA-2, Page 1 of 1

	Current (a)	2012	2013	2014	2015	2016
30-Yr. Treasury						
Value Line (b)	3.4%	3.9%	4.1%	4.5%	5.0%	--
IHS Global Insight (c)	3.4%	3.3%	3.8%	4.5%	5.1%	5.3%
Blue Chip (d)	3.4%	3.7%	4.2%	4.8%	5.3%	5.5%
AAA Corporate						
Value Line (b)	4.2%	4.6%	4.7%	5.2%	5.7%	--
IHS Global Insight (c)	4.2%	4.2%	4.5%	5.1%	6.0%	6.2%
Blue Chip (d)	4.2%	4.3%	4.7%	5.4%	5.8%	6.2%
S&P (e)	4.2%	4.2%	4.6%	5.1%	6.0%	--
AA Utility						
IHS Global Insight (c)	4.3%	4.4%	4.9%	5.6%	6.5%	6.8%
EIA (f)	4.3%	4.7%	4.8%	5.7%	6.8%	6.9%

(a) Based on monthly average bond yields for the six-month period Jul. - Dec. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases/h15/data.htm.

(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 25, 2011).

(c) IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011).

(d) *Blue Chip Financial Forecasts,* Vol. 30, No. 12 (Dec. 1, 2011).

(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Just Like Ol' Times," *RatingsDirect* (Jan. 12, 2012).

(f) Energy Information Administration, *Annual Energy Outlook 2012, Early Release* (Jan. 23, 2012).

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

EXHIBIT LC-13

NATIONAL GROUP
VALUE LINE EXPECTED ROE

Company	Expected ROE
ALLETE	9.00%
Ameren Corp.	9.50%
American Elec Pwr	10.00%
Avista Corp.	8.50%
Black Hills Corp.	9.00%
Cleco Corp.	10.50%
CMS Energy Corp.	13.50%
DTE Energy Co.	10.00%
Duke Energy Corp.	8.00%
Edison International	11.00%
El Paso Electric	9.50%
Empire District Elec	8.50%
Entergy Corp.	10.00%
Great Plains Energy	8.00%
Hawaiian Elec.	9.50%
IDACORP, Inc.	8.00%
Otter Tail Corp.	12.50%
PG&E Corp.	8.50%
PNM Resources	9.50%
Portland General Elec.	8.50%
Pub Sv Enterprise Grp	10.50%
SCANA Corp.	10.00%
Sempra Energy	11.50%
Westar Energy	9.50%
Median	9.5%
Average	9.7%

Source: Exhibit ESI-107

Control Number: 42866

Item Number: 88

Addendum StartPage: 0

SOAH DOCKET NO. 473-14-5144.WS
PUC DOCKET NO. 42866

PETITION OF TRAVIS COUNTY	§	BEFORE THE STATE OFFICE
MUNICIPAL UTILITY DISTRICT	§	
NO. 12 APPEALING CHANGE OF	§	
WHOLESALE WATER RATES	§	
IMPLEMENTED BY WEST	§	
TRAVIS COUNTY PUBLIC	§	OF
UTILITY AGENCY, CITY OF BEE	§	
CAVE, TEXAS, HAYS COUNTY,	§	
TEXAS AND WEST TRAVIS	§	
COUNTY MUNICIPAL UTILITY	§	
DISTRICT NO. 5	§	ADMINISTRATIVE HEARINGS

DIRECT TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF

WEST TRAVIS COUNTY PUBLIC UTILITY AGENCY

DECEMBER 19, 2014

DIRECT TESTIMONY OF
RICHARD A. BAUDINO

TABLE OF CONTENTS

ATTACHMENTS

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

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

A. My name is Richard A. Baudino. I am a Consultant with J. Kennedy and Associates, Inc., an economic consulting firm specializing in utility ratemaking and planning issues. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I provide this information in Attachment A, including a list of my testimony experience.

Q. ARE YOU FAMILIAR WITH P.U.C. SUBST. R. 24.133, THE PUBLIC INTEREST TEST, AS IT RELATES TO THE PUBLIC UTILITY COMMISSION'S ("PUC" OR "COMMISSION") REVIEW OF WHOLESALE WATER RATES?

A. Yes, I am. I understand that the issue of whether the wholesale rates adversely impact the public interest is the sole focus of this proceeding.

B. Summary

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of West Travis County Public Utility Agency ("WTCPUA").

3. TCMUD 12 had substantial bargaining power in its negotiations with the LCRA (now the WTCPUA). The LCRA (now the WTCPUA) did not have disparate bargaining power over TCMUD 12 during the negotiation of the original wholesale water treatment services contract, the negotiation of the assignment of that contract, or the adoption of the protested rates.

4. The LCRA (now the WTCPUA) did not have sole control over the price of its wholesale water treatment service or the quantities provided. TCMUD 12 had significant input into the amount and the price of water treatment services it received from the LCRA (now the WTCPUA).

5. The WTCPUA is not abusing monopoly power. Rather, it is acting in a prudent manner according to the wholesale water treatment services agreement it acquired from the LCRA.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section II of my testimony will present a brief explanation of the creation of the WTCPUA and of the wholesale water treatment services agreement that TCMUD 12 originally entered into with the LCRA and that was later assigned to the WTCPUA. This historical background is important because it establishes the LCRA, and later the WTCPUA, not as a monopolist, but rather as a sole source provider of water treatment services pursuant to an agreement with TCMUD 12. At the time this agreement was entered into, TCMUD 12 had at least one other option to taking wholesale water treatment services from the LCRA. However, it is unclear if TCMUD 12 did a thorough investigation of other potential providers of these services.

which the LCRA agreed to provide wholesale services for the treatment of raw water, and the delivery of that treated water to TCMUD 12.[1] The obligations of the LCRA under the TCMUD 12 Agreement were transferred to the WTCPUA, with the agreement of the TCMUD 12, through the "Agreement Regarding Transfer of Operations of the West Travis County Water System from the Lower Colorado River Authority, to the West Travis County Public Utility Agency," ("2012 Amendment") between LCRA, WTCPUA, and TCMUD 12, effective on March 19, 2012.[2] By virtue of these agreements, the WTCPUA accepted the responsibility of serving the customers, including TCMUD 12, that were formerly served by the LCRA. Essentially, the WTCPUA stepped into the shoes of the LCRA's TCMUD 12 Agreement.

III. ANALYSIS OF MARKET POWER AND BARGAINING POWER

A. 2009 TCMUD 12 Agreement

Q. DID TCMUD 12 ORIGINALLY HAVE ALTERNATIVES TO PURCHASING WATER TREATMENT SERVICES FROM THE LCRA?

A. Yes. TCMUD 12 witness DiQuinzio admits that TCMUD 12 had alternatives to LCRA's water treatment services.[3] In 2009, TCMUD 12 apparently determined that the alternatives were more expensive than purchasing wholesale water treatment services from LCRA. TCMUD 12 then opted to purchase wholesale water treatment services from LCRA.

---

[1] The TCMUD 12 Agreement is attached to the testimony of Mr. Donald G. Rauschuber. In the interest of conserving resources, I am not also attaching it to my testimony.

[2] The 2012 Amendment is attached to the testimony of Mr. Donald G. Rauschuber. In the interest of conserving resources, I am not also attaching it to my testimony.

[3] Direct Testimony of Joseph A. DiQuinzio, Jr. at 5-6 and 13 (Oct. 31, 2014).

to the operation and maintenance of the system and associated expenses, all related to the system used to provide the wholesale water treatment services.

Q. DOES ARTICLE IV OF THE TCMUD 12 AGREEMENT CONTAIN LANGUAGE THAT INDICATES THAT THE SYSTEM WAS SET UP BY THE LCRA AND ITS CUSTOMERS FOR THEIR MUTUAL BENEFIT?

A. Yes. Section 4.03 – <u>LCRA System to be Self-Sufficient</u> contains the following agreement:

> The LCRA System shall be comprised of the facilities described in Recital No. 1, together with such improvements, extensions, enlargements, betterments, additions, and replacements thereto as are reasonable and necessary to provide water to the LCRA Service Area and Wholesale Water Services to District No. 12 on behalf of the Districts. The parties agree that the Costs of the LCRA System shall be allocated to and borne by all of the customers of the LCRA System, including District No. 12, in a fair and equitable manner and so that the LCRA System is self-sufficient.

The facilities referred to in Recital No. 1 comprise the West Travis County Regional Water System. This language is quite clear that LCRA and its customers entered into a mutually beneficial agreement whereby the LCRA provided water treatment services at cost, that rates would be non-discriminatory, and that those rates would support the system being self-sufficient.

Q. DID THE TCMUD 12 AGREEMENT PROVIDE AN AVENUE FOR TCMUD 12 TO PROTEST, DISPUTE OR APPEAL THE CHARGES AND RATES CONTAINED IN THE AGREEMENT?

A. Yes. Section 6.06 – <u>Protests, Disputes or Appeals</u> protected TCMUD 12's rights to dispute and even appeal the rates and charges from LCRA:

Q. DOES THE FOREGOING DISCUSSION SUPPORT YOUR VIEW THAT INSTEAD OF BEING A MONOPOLY, LCRA WAS CHOSEN IN 2009 BY TCMUD 12 AS A SOLE PROVIDER OF WHOLESALE WATER TREATMENT SERVICES?

A. Yes. It is quite clear that in 2009 TCMUD 12 chose the LCRA to be its sole provider and that the TCMUD 12 Agreement was freely negotiated between the LCRA and TCMUD 12 for the mutual benefit of both parties. It is clear from the terms of the TCMUD 12 Agreement that TCMUD 12 is a large customer that was fully capable of negotiating contract terms and protections for its position as a buyer of services from LCRA. Recital No. 4 of the TCMUD 12 Agreement underscores this with the following language:

> District No. 12 desires to obtain wholesale services for the treatment of raw water and delivery of potable water to District No. 12, on behalf of the Districts, from the LCRA System, and LCRA desires to provide such services to District No. 12, on behalf of the Districts.

Q. MR. BAUDINO, WHY IS IT IMPORTANT FOR THE PUC TO UNDERSTAND THE HISTORICAL RELATIONSHIP BETWEEN LCRA AND TCMUD 12 IN ITS DETERMINATION OF WHETHER THE WTCPUA IS ACTING AS A MONOPOLY?

A. It is vitally important because, as described above, the WTCPUA stepped into the shoes of the LCRA with respect to its provision of wholesale water treatment services to TCMUD 12 and other customers who formerly took service from the LCRA. The original TCMUD 12 Agreement that was negotiated between the LCRA and TCMUD 12 was, in my opinion, clearly an arms-length transaction that established the LCRA as a sole source provider of wholesale water treatment services to TCMUD 12, not as

C. Adoption of 2013 Rates

Q. DO YOU HAVE AN OPINION AS TO THE BARGAINING POWER OF TCMUD 12 AT THE TIME THAT THE WTCPUA ADOPTED THE RATES THAT ARE THE SUBJECT OF THIS PROCEEDING?

A. Yes. Based on WTCPUA witness Mr. Rauschuber's Direct Testimony, the WTCPUA undertook extensive efforts to involve its wholesale customers in the development of the wholesale water treatment services rates prior to their adoption in November 2013. The fact that the WTCPUA undertook these efforts and used the input received from the wholesale customers, and the additional fact that the WTCPUA afforded the customers an opportunity to revise their contractual obligations, leads me to conclude that the TCMUD 12 exercised significant bargaining power prior to the adoption of the 2013 rates by the WTCPUA.

D. Monopoly Market Structure and its Applicability to the LCRA and the WTCPUA.

Q. ACCORDING TO ECONOMIC LITERATURE, WHAT CONDITIONS CHARACTERIZE A MONOPOLY MARKET STRUCTURE?

A. In economics literature, there are several generally recognized conditions that characterize a pure monopoly market structure. For purposes of this proceeding, I refer to *Microeconomics: Principles, Problems, and Policies* by Campbell R. McConnell, Stanley L. Brue, and Sean M. Flynn. This is one of the standard textbooks on basic microeconomic theory and is used in universities throughout the United States. This book is also commonly relied upon by economists. In Chapter 12, Pure Monopoly, the authors provide five basic characteristics of a monopoly market. These five characteristics are as follows:

Agreement between the LCRA and TCMUD 12 and evaluate whether the LCRA was a monopoly provider of wholesale water treatment services to TCMUD 12.

Q. PLEASE ADDRESS THESE MONOPOLY CHARACTERISTICS AS APPLIED TO THE LCRA/WTCPUA.

A. In conducting my examination, I will apply the first, third, and fourth characteristics of a monopoly market to the wholesale water treatment services provided first by the LCRA and then by the WTCPUA. In one sense, it is correct that there are no *existing* adequate substitutes for wholesale water treatment services, but TCMUD 12 chose not to exercise an ownership alternative or to seek alternative providers of those services.

Q. THE FIRST NOTED CHARACTERISTIC OF A MONOPOLY MARKET IS THAT THERE IS ONLY ONE PROVIDER OF A GOOD OR SERVICE. WAS THE LCRA THE ONLY OPTION FOR THE PROVISION OF WHOLESALE WATER TREATMENT SERVICES TO TCMUD 12?

A. No. TCMUD 12 chose the LCRA as a sole source provider after looking at its available options and determining that the LCRA was the most economic provider of wholesale water treatment services. TCMUD 12 witness DiQuinzio described this process in his Direct Testimony.[5] DiQuinzio explained that TCMUD 12 made the decision that building and operating its own system would have been more expensive than taking service from the LCRA, and then it decided to negotiate a separate wholesale water services agreement with the LCRA. Therefore, it is clear that

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[5] Direct Testimony of Joseph A. DiQuinzio, Jr. at 5-6 (Oct. 31, 2014).

Q. IF TCMUD 12 FAILED TO FULLY EXPLORE ITS OPTIONS FOR WHOLESALE WATER TREATMENT SERVICES, CAN ONE OBJECTIVELY CONCLUDE THAT EITHER THE LCRA OR THE WTCPUA ACTED AS MONOPOLISTS?

A. Absolutely not. Without full knowledge of available alternative wholesale water treatment services at the time the TCMUD 12 Agreement was entered into by the LCRA and TCMUD 12, one cannot reasonably conclude that the LCRA acted as a monopoly provider of wholesale water treatment services to TCMUD 12.

Furthermore, since the WTCPUA essentially stepped into the shoes of the LCRA in terms of assuming its rights and responsibilities under the TCMUD 12 Agreement, one also cannot conclude that the WTCPUA is a monopoly provider of wholesale water treatment services to TCMUD 12.

Q. GIVEN THE FOREGOING DISCUSSION, IS IT APPROPRIATE FOR TCMUD 12 TO NOW ARGUE THAT THE WTCPUA IS OPERATING AS A MONOPOLIST?

A. No. In my view, it is highly inappropriate for TCMUD 12 to be arguing at this point in time that the WTCPUA is operating as a monopoly. Basically, TCMUD 12 chose the LCRA (now the WTCPUA) as a sole source provider of wholesale water treatment services after looking at the alternative of owning the treatment facilities itself. The LCRA (now the WTCPUA) was a lower cost, more economic alternative. Furthermore, it is not clear that TCMUD 12 fully and prudently explored all the options available to it at the time it originally entered into the TCMUD 12 Agreement with the LCRA. TCMUD 12 has simply not made the case that the WTCPUA is now operating as a monopoly provider of wholesale water treatment services.

TCMUD 12 is now claiming that the WTCPUA is a monopolist. Clearly, the LCRA (now the WTCPUA) is a sole source provider of wholesale water treatment services based on a negotiated agreement. Therefore, The WTCPUA is not a monopolist.

Q. WITH RESPECT TO THE THIRD CHARACTERISTIC OF A MONOPOLY MARKET, WAS EITHER THE LCRA OR THE WTCPUA A PRICE MAKER WITH COMPLETE CONTROL OVER PRICES AND QUANTITIES?

A. No, definitely not. As I describe above, TCMUD 12 is a large consumer of wholesale water treatment services and voluntarily entered into negotiations with the LCRA for those services. Those negotiations produced the 2009 TCMUD 12 Agreement between the LCRA and TCMUD 12. The TCMUD 12 Agreement contained the rate agreements and service protections I described earlier. In addition, Mr. DiQuinzio testified in his Direct Testimony that TCMUD 12 entered into an extended period of negotiations for specific quantities of water to be treated by the LCRA.[8] Indeed, this was an arms-length transaction between a buyer and a seller for wholesale water utility service and TCMUD 12 provided no evidence that the LCRA was solely in control of the quantities or prices negotiated and ultimately agreed to by both parties.

This third characteristic also was not present in 2012 when the WTCPUA assumed the TCMUD 12 Agreement as part of its purchase of the West Travis County Regional Wholesale Water and Wastewater System ("LCRA System"). As part of its agreement to purchase the LCRA System, the WTCPUA was obligated to obtain the consent of TCMUD 12 to assign the TCMUD 12 Agreement from LCRA to the WTCPUA. Under the TCMUD 12 Agreement, TCMUD 12 could withhold its consent to assignment under limited certain circumstances. However, TCMUD 12

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8 Direct Testimony of Joseph A. DiQuinzio, Jr. at 6-7 (Oct. 31, 2014).

reduce their contractual obligation with the WTCPUA, which is clear evidence that the WTCPUA was not acting as a monopolist, and was not a price maker.

The fact that TCMUD 12 was able to negotiate additional considerations from the LCRA and the WTCPUA, and had an opportunity to change the quantity of services purchased from the WTCPUA, shows that it had substantial bargaining power, which is relevant to the P.U.C. SUBST. R. 24.133(a)(3)(A). TCMUD 12 also had additional leverage in terms of being asked for its approval of the proposed transfer of assets from the LCRA to the WTCPUA.

Q. THE FOURTH NOTED CHARACTERISTIC OF A MONOPOLY MARKET IS THAT THERE ARE INSURMOUNTABLE BARRIERS TO ENTRY. ARE THERE INSURMOUNTABLE BARRIERS TO ENTRY IN THE WHOLESALE MARKET FOR WATER TREATMENT SERVICES IN TCMUD 12'S SERVICE AREA?

A. No. In examining barriers to entry, there are several types to be considered. First, exclusive service franchises and service territories may be granted by governmental authorities to public utilities, and so constitute insurmountable legal barriers to entry. The purpose of franchises and service territories is to protect the utility from competition. In return, the utility accepts some form of regulation by the governmental entity that granted the franchise or service territory, and usually is tasked with an obligation to serve everyone within the territory. There is no exclusive franchise or exclusive territory for wholesale water treatment services in TCMUD 12's geographical area, so this barrier to market entry does not exist.

Second, the monopolist may have ownership or control of essential resources. This condition could apply to the LCRA's provision of raw water to TCMUD 12 in copper industries.[10] High cost of entry is a barrier to entry in the jet engine, automobile, commercial aircraft, and petroleum-refining industries.[11]

The important point here is that the presence of economies of scale and high cost of entry do not necessarily point to a monopoly market. Oligopolistic industries also possess these barriers to entry and the industries cited by McConnell/Brue/Flynn are not regulated as to prices charged and/or quantities produced.

IV. RESPONSE TO TCMUD 12 WITNESS ZARNIKAU

Q. ON PAGE 5, LINES 14 AND 15 OF HIS DIRECT TESTIMONY, TCMUD 12 WITNESS ZARNIKAU CONCLUDED THAT THE WTCPUA IS A MONOPOLY. DO YOU HAVE ANY GENERAL COMMENTS ON HIS CONCLUSION REGARDING THE ALLEGED MONOPOLY STATUS OF THE WTCPUA?

A. Yes. As a general matter, TCMUD 12 witness Zarnikau failed to address the history of the TCMUD 12 Agreement and the bargaining between TCMUD 12 and the LCRA. He took a sole supplier agreement and concluded that this was evidence of a monopoly. This logic and approach is fatally flawed for the reasons I have already discussed.

As I stated earlier in my testimony, it is critical to understand how TCMUD 12 and the LCRA reached the TCMUD 12 Agreement that was assumed by the WTCPUA in 2012. The WTCPUA stepped into the role of a sole source provider of wholesale water treatment services for TCMUD 12 pursuant to an already existing

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[10] Campbell R. McConnell, Stanley L. Brue, and Sean M. Flynn, *Microeconomics: Principles, Problems, and Policies* at 286 (2013) (*see* Attachment B).

[11] *Id.* at 287.

would be associated with such a system. TCMUD 12 witness Zarnikau provided no economic, financial, or accounting analysis of his own with which one could compare the per unit costs of a new system with the costs and rates at which the LCRA was willing to provide wholesale water treatment services. In my opinion, Zarnikau does not provide an adequate foundation for his conclusion. Apparently, TCMUD 12 also failed to consider such alternatives as whether development of a water treatment system could be phased-in or totally built out, which could also affect the economics of alternative water treatment options.

Q. ON PAGE 8, LINES 21 THROUGH 24, TCMUD 12 WITNESS ZARNIKAU TESTIFIED THAT BUILDING A NEW SYSTEM "MIGHT LEAD TO THE ABANDONMENT OF CAPACITY RESERVED ON THE SYSTEM CONTROLLED BY THE SUPPLIERS WHICH TCMUD 12 HAS ALREADY PAID FOR." DO YOU AGREE?

A. No. Zarnikau's point here is extremely important, but not in the manner he suggests. The fact is that TCMUD 12 had a very strong financial incentive to continue taking service under the TCMUD 12 Agreement that was assumed by the WTCPUA. Based on the TCMUD 12 Agreement that TCMUD 12 negotiated with the LCRA, TCMUD 12 was credited with the Connection Fees it paid, and in return, was guaranteed reservation capacity in the LCRA system for the number of living unit equivalents ("LUE") for which a Connection Fee had been paid up to TCMUD 12's contractual capacity of 2,125 LUEs. Mr. DiQuinzio noted in his Direct Testimony that one of the critical provisions that induced TCMUD 12 to approve the 2012 Amendment was the transfer of the paid Connection Fees from the LCRA to the WTCPUA, which ensured that TCMUD 12 received full credit for the paid

Q. ON PAGES 8 THROUGH 9 OF HIS DIRECT TESTIMONY, TCMUD 12 WITNESS ZARNIKAU SPECULATED ON HOW THE WTCPUA MIGHT RESPOND TO AN ATTEMPT BY TCMUD 12 TO DEVELOP A COMPETING SYSTEM THAT WOULD REPLACE THE WTCPUA'S WATER TREATMENT SYSTEM. DO YOU AGREE WITH HIS SPECULATION?

A. No. Not only is Zarnikau's testimony irrelevant, it is completely inapplicable as to the question of whether the WTCPUA is a monopoly. The "No Competition" provision in the "Acquisition, Water Supply, Wastewater Treatment and Conditional Purchase Agreement" is between ***the Participants of the WTCPUA***, not between the WTCPUA and any of its wholesale customers. Section 7.07(h) of this agreement essentially protects the value of the assets purchased by the WTCPUA from the LCRA. This clause is mutually beneficial to the Participants of the WTCPUA. It does not, and cannot, prohibit competition from other providers of wholesale water treatment service.

Q. ON PAGE 10 OF HIS DIRECT TESTIMONY, TCMUD 12 WITNESS ZARNIKAU CITED § 13.001(b) OF THE TEXAS WATER CODE AND § 31.001(B) OF THE PUBLIC UTILITY REGULATORY ACT WITH RESPECT TO THE DEFINITIONS OF RETAIL PUBLIC UTILITIES. DO THESE PROVISIONS HAVE ANY BEARING ON THE WTCPUA'S PROVISION OF WHOLESALE WATER TREATMENT SERVICES TO TCMUD 12?

A. No. The issue before the PUC is whether the WTCPUA is a monopoly provider of *wholesale* water treatment services to TCMUD 12. Zarnikau misinterprets Texas that in 2013 there were, indeed, no practical alternatives, this does not suggest that the WTCPUA now suddenly has disparate bargaining power.

TCMUD 12 witness Zarnikau claimed further evidence of disparate bargaining power when the Board of the WTCPUA allegedly ignored the concerns TCMUD 12 expressed over the rates the WTCPUA put into effect for calendar year 2014.[17] His allegation here is without merit. As I stated earlier in my testimony, the TCMUD 12 Agreement that the WTCPUA assumed from the LCRA provided in Section 6.06 that TCMUD 12 had the power to protest rates charged by the LCRA, to continue to receive service during the pendency of such protest, and that rates collected subject to protest would be placed in an interest-bearing account. Section 7.02 provided TCMUD 12 the ability to examine the books and records of the LCRA with respect to its rates and charges. These protections were preserved when the WTCPUA assumed the TCMUD 12 Agreement. The mere fact that the WTCPUA implemented new rates for calendar year 2014 does not suggest any disparate bargaining power on the part of the WTCPUA. Furthermore, the TCMUD 12 Agreement allows for such rate changes in Section 4.01.f., as follows:

> At any time while this Agreement is in effect, LCRA, subject to applicable law, may modify the Connection Fee, the Monthly Charge and the Volume Rate consistently with the terms of this Agreement as appropriate to recover the Costs of the LCRA System in a just, reasonable and nondiscriminatory manner from District No. 12 and the other customers of the LCRA System.

Based on my reading on the TCMUD 12 Agreement, the WTCPUA acted within its rights according to Section 4.01.f.

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[17] *Id.* at 15, lines 14-18.

> cover the costs of its services, and LCRA would keep the surcharge to cover LCRA's costs of administration.

This is not an abuse of monopoly power in any way. This is simply an example of the WTCPUA collecting contractual costs pursuant to the TCMUD 12 Agreement. The administrative charge being collected by the WTCPUA will not be kept by the WTCPUA, but will be transferred to the LCRA as compensation for its services in administering the remaining wholesale services agreements of Deer Creek Water Company and Lazy Nine MUD No. 1A.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO TCMUD 12 WITNESS ZARNIKAU'S ALLEGATIONS OF ABUSE OF MONOPOLY POWER ON THE PART OF THE WTCPUA.

A. Even if the PUC concludes that the WTCPUA is a monopoly, which I do not support, the WTCPUA did not abuse any such monopoly power with respect to the standard of P.U.C. SUBST. R. 24.133(a)(3)(A), Determination of Public Interest. In my opinion, the WTCPUA acted within its rights and responsibilities according to the TCMUD 12 Agreement assumed from the LCRA, which originally had been negotiated between the LCRA and TCMUD 12.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric Industry Restructuring and Competition
Fuel Cost Auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

EXPERIENCE

1989 to Present: Kennedy and Associates: **Consultant** – Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: New Mexico Public Service Commission Staff: **Utility Economist** – Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

Expert Testimony Appearances
of
Richard A. Baudino
(As of December 2014)

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co of NM	Rate design
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co	Rate of return
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electrico Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co	Revenue requirements, rate design, rate of return
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development
01/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co	Rate of return, rate design
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co	Rate of return, expense from affiliated interest
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co	Cost of equity
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co	Transportation rates

Expert Testimony Appearances
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(As of December 2014)

Date	Case	Jurisdict.	Party	Utility	Subject
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide all utilities	Investigation into Electric Power Competition
05/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service
07/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co , Potomac Electric Power Co. and Constellation Energy Corp	Return on equity.
07/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co	Return on equity, rate of return.
09/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc	Return on equity.
01/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp	Revenue requirements, rate of return and cost of service.
03/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design
07/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
07/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania American Water Co.	Rate of return, cost of service, revenue requirements.
03/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
07/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
08/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro- Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW, and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return
03/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Return on equity.
03/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
04/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs
06/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Cost of debt.
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co	Revenue requirements, cost allocation, rate design
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc , and North Penn Gas Co	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Commission	Louisiana Electric Cooperative	Rate restructuring.

Expert Testimony Appearances
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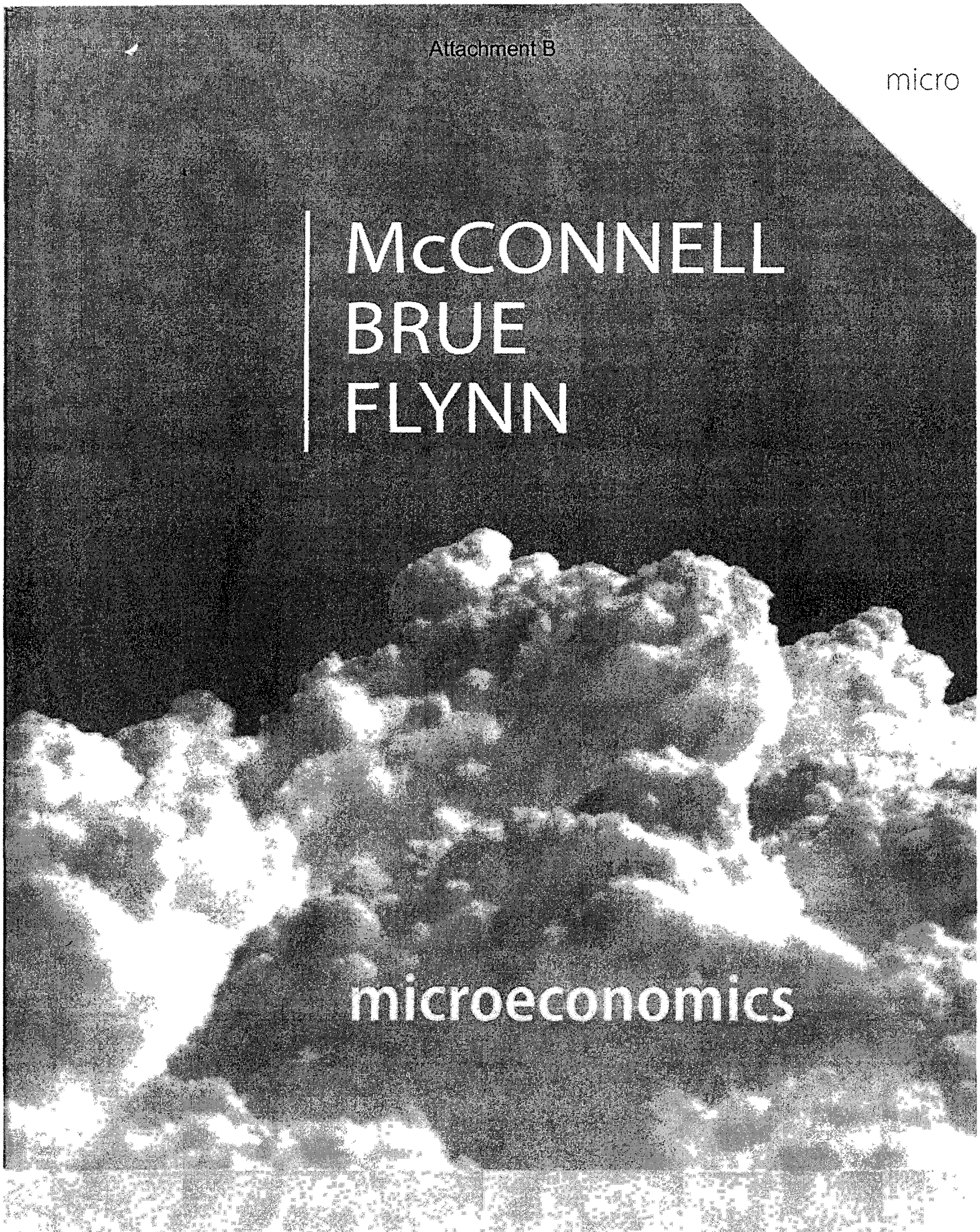
(As of December 2014)

Date	Case	Jurisdict.	Party	Utility	Subject
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co	Revenue requirement, cost allocation, rate design, tariff issues
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power& Light Co.	Return on equity, weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison	Return on equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power, LLC and Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, tariff issues
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel and Univ. of Pittsburgh Med. Center	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc	Capital structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation

Expert Testimony Appearances
of
Richard A. Baudino
(As of December 2014)

Date	Case	Jurisdict.	Party	Utility	Subject
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric, Kentucky Utilities	Return on equity
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal of Felman Production, LLC
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al	FERC	Louisiana Public Service Commission	Entergy Services, Inc	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation

Attachment B



QUICK REVIEW 13.1

- Monopolistic competition involves a relatively large number of firms operating in a noncollusive way and producing differentiated products with easy industry entry and exit.
- In the short run, a monopolistic competitor will maximize profit or minimize loss by producing that output at which marginal revenue equals marginal cost.
- In the long run, easy entry and exit of firms cause monopolistic competitors to earn only a normal profit.
- A monopolistic competitor's long-run equilibrium output is such that price exceeds the minimum average total cost (implying that consumers do not get the product at the lowest price attainable) and price exceeds marginal cost (indicating that resources are underallocated to the product).
- The efficiency loss (or deadweight loss) associated with monopolistic competition is greatly muted by the benefits consumers receive from product variety.

Oligopoly

LO13.5 Describe the characteristics of oligopoly.

In terms of competitiveness, the spectrum of market structures reaches from pure competition, to monopolistic competition, to oligopoly, to pure monopoly (review Table 10.1). We now direct our attention to **oligopoly,** a market dominated by a few large producers of a homogeneous or differentiated product. Because of their "fewness," oligopolists have considerable control over their prices, but each must consider the possible reaction of rivals to its own pricing, output, and advertising decisions.

A Few Large Producers

The phrase "a few large producers" is necessarily vague because the market model of oligopoly covers much ground, ranging between pure monopoly, on the one hand, and monopolistic competition, on the other. Oligopoly encompasses the U.S. aluminum industry, in which three huge firms dominate an entire national market, and the situation in which four or five much smaller auto-parts stores enjoy roughly equal shares of the market in a medium-size town. Generally, however, when you hear a term such as "Big Three," "Big Four," or "Big Six," you can be sure it refers to an oligopolistic industry.

Homogeneous or Differentiated Products

An oligopoly may be either a **homogeneous oligopoly** or a **differentiated oligopoly,** depending on whether the firms in the oligopoly produce standardized (homogeneous) or differentiated products. Many industrial products (steel, zinc, copper, aluminum, lead, cement, industrial alcohol) are virtually standardized products that are produced in oligopolies. Alternatively, many consumer goods industries (automobiles, tires, household appliances, electronics equipment, breakfast cereals, cigarettes, and many sporting goods) are differentiated oligopolies. These differentiated oligopolies typically engage in considerable nonprice competition supported by heavy advertising.

Control over Price, but Mutual Interdependence

Because firms are few in oligopolistic industries, each firm is a "price maker"; like the monopolist, it can set its price and output levels to maximize its profit. But unlike the monopolist, which has no rivals, the oligopolist must consider how its rivals will react to any change in its price, output, product characteristics, or advertising. Oligopoly is thus characterized by *strategic behavior* and *mutual interdependence*. By **strategic behavior,** we simply mean self-interested behavior that takes into account the reactions of others. Firms develop and implement price, quality, location, service, and advertising strategies to "grow their business" and expand their profits. But because rivals are few, there is **mutual interdependence:** a situation in which each firm's profit depends not just on its own price and sales strategies but also on those of the other firms in its highly concentrated industry. So oligopolistic firms base their decisions on how they think their rivals will react. Example: In deciding whether to increase the price of its cosmetics, L'Oréal will try to predict the response of the other major producers, such as Clinique. Second example: In deciding on its advertising strategy, Burger King will take into consideration how McDonald's might react.

Entry Barriers

The same barriers to entry that create pure monopoly also contribute to the creation of oligopoly. Economies of scale are important entry barriers in a number of oligopolistic industries, such as the aircraft, rubber, and copper industries. In those industries, three or four firms might each have sufficient sales to achieve economies of scale, but new firms would have such a small market share that they could not do so. They would then be high-cost producers, and as such they could not survive. A closely related barrier is the large expenditure for capital—the c

RFP NO. 1-16:

Produce all documents and correspondence between MUD 12 and third parties regarding the provision of Water Treatment Services to MUD 12.

RESPONSE:

Miguel A. Huerta, Counsel for TCMUD 12 conferred with David Klein and Georgia Crump, Counsel for the WTCPUA regarding this request. By agreement of Counsel, the phrase "Water Treatment Services" as used in this request, is defined by the entire definition of the term "Water Treatment Services" as set forth in the Instructions.

After a diligent search, TCMUD 12 has not identified any documents responsive to this request.

Prepared by:
Witness: Joe DiQuinzio

RFA NO. 1-42:

Admit or deny that MUD 12 received correspondence from the PUA or its representatives regarding a meeting held at 12117 Bee Cave Road, Building 3, Suite 120, Bee Cave, Texas 78738 on May 14, 2013, regarding the PUA's wholesale Water Treatment Services rates.

RESPONSE:

Admit that on May 10, 2013 a representative of MUD 12 received an email from Nelissa Heddin regarding a WTCPUA Wholesale Customer Committee Meeting to be held on May 14, 2013.

RFA NO. 1-43:

Admit or deny that one or more representatives of TCMUD 12 attended a meeting held at 12117 Bee Cave Road, Building 3, Suite 120, Bee Cave, Texas 78738 on May 14, 2013, regarding the PUA's wholesale Water Treatment Services rates.

RESPONSE:

Admit.

RFA NO. 1-44:

Admit or deny that between January 1, 2009 and March 6, 2014, officials, employees, representatives, and/or contractors of MUD 12 engaged in discussions or meetings with officials, employees, representatives, or contractors of other water providers, other than LCRA or the PUA, for a supply of treated water.

RESPONSE:

Deny. *See also* TCMUD 12 Response to PUA RFP 1-2.

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, to Conduct a Biennial Review of Costs and Rates - Test Year 2015

Docket No. 05-UR-107

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

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. Did you submit Direct Testimony in this proceeding?

A. Yes, I submitted Direct Testimony on behalf of the Wisconsin Industrial Energy Group, Inc. ("WIEG").

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimonies filed by Mr. Corey Singletary and Mr. Jerry Albrecht, witnesses for the Staff of the Public Service Commission of Wisconsin ("WPSC") and Mr. Jonathan Wallach, witness for the Citizens Utility Board ("CUB"). My response to these witnesses is organized by major subject area as follows:

- Class cost of service study issues.
- Customer class revenue allocation.
- Real Time Market Pricing ("RTMP") Rider.

<u>Class Cost of Service Study ("CCOSS") Issues</u>

Q. Please summarize the position of Mr. Singletary regarding the classification and allocation of Wisconsin Electric Power Company's ("WEPCO") production plant.

A. Mr. Singletary presented the results of five class cost of service studies ("CCOSS") in his Direct Testimony and in Schedule 1 of Ex.-PSC-Singletary-1. These five studies consist of the following:

- Adjusted WEPCO "base case" with revenue requirement levels settled with the Company.
- Scenario 1: WEPCO "base case" using 05-UR-106 distribution allocators.
- Scenario 2: WEPCO "base case: with 12CP production demand allocation.
- Scenario 3: Scenario 2 with 60/40 demand/energy production plant allocation and 10/90 production O&M allocation.
- Scenario 4: Scenario 3 and 100% demand distribution allocation.

Q. What is Mr. Singletary's position with respect to WEPCO's "base case" CCOSS?

A. Mr. Singletary disagreed with WEPCO's "base case" CCOSS, which classified and allocated production plant using 75% 4CP demand and 25% energy. He testified at Direct-PSC-Singletary-5 that "it is important to recognize that the utility's production plant, including peaking resources, provides reliability in every month of the year." Mr. Singletary continued that MISO has "strict rules" that require utilities to ensure that their plants are available to operate during the entire year and that maintenance scheduling is also subject to strict rules. Based on this reasoning, Mr. Singletary concluded that WEPCO's generating plants provide reliability during the entire year, not just the four summer months. Mr. Singletary further testified at Direct-PSC-Singletary-6, lines 6 through 9, that utilities ensure that their generation is available during non-summer months to "hedge against the risk of purchasing energy at a high cost."

Q. Did CUB witness Wallach object to WEPCO's base case CCOSS?

A. Yes. Mr. Wallach noted his objections to the Company's base case CCOSS and to the allocation of production costs using the 4CP method at Direct-CUB-Wallach-13.

Q. Are Mr. Singletary's arguments against the 4CP method well taken?

A. No. Mr. Singletary confused reliability with cost causation. I would agree that it is important to have reliable capacity throughout the year to meet customer loads, but it is the summer peak that drives capacity requirements and availability. System reliability is most important during the peak summer months when demands are at their highest. In the non-summer months, when demands are much lower, WEPCO is able to schedule planned outages for its generating units. The Company simply would not schedule a planned outage during the four peak summer months. Mr. Singletary missed this important point regarding cost causation.

The graph I presented in Figure 1 in my Direct Testimony shows consistently higher peak demands during the summer months over a six-year period. This historical data provides strong support for using the 4CP method to allocate production plant costs to customer classes.

This is consistent with Mr. Rogers Direct Testimony in 05-UR-106, Direct-WEPCO/WG-Rogers-13, in which Mr. Rogers testified as follows:

> The National Association of Regulatory Utility Commissioners ―Electric Utility Cost 1 Allocation Manual (NARUC Manual) describes the 12CP method on page 46. It states, "This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky." For many years this described our load shape, but over the course of the past few decades the difference between our summer peaks and winter peaks have become more pronounced. Although what we‘ve argued in the past, (that we must plan for capacity in all twelve months of the year), is still true, our summer peaks are clearly the primary determinant of our capacity planning.

Q. On Direct-PSC-Singletary-6 Mr. Singletary cited the "Polar Vortex" as a "simple example" highlighting the need to consider capacity in all months of the year. Please respond to Mr. Singletary's example.

A. A highly unusual weather occurrence such as the Polar Vortex does not justify using a 12CP allocation factor for production plant. The circumstances surrounding the extreme cold temperatures during January and February of 2014 simply are not predictable. Normally, winter peaks are much lower than summer peaks for WEPCO. Therefore, WEPCO's consistent pattern of significantly higher summer peaks over time should be the determinative consideration for customer cost causation in a CCOSS.

To sum up, the 12CP does not accurately track customer cost causation. It does not follow what we know about the historically higher summer peaks that WEPCO experiences on its system. The 12CP method of allocating production plant costs should be rejected by the Commission.

Q. Please address Scenario 3, which allocates production plant using a 40% energy-based weighting and production O&M using a 90% energy-based weighting.

A. Mr. Singletary's Scenario 3 is unreasonable and should be rejected by the Commission.

For the reasons I explained in my Direct Testimony, classifying any production plant as energy-related is inappropriate. Energy usage throughout the year is not the driver of WEPCO's generating plant investment. Rather, it is the high demand summer period for which WEPCO plans its capacity. All of WEPCO's generation must be on line and available to meet summer demands. A 4CP allocation of production plant recognizes this fact and correctly apportions cost responsibility to customers based on their contribution to those peak demands.

In addition, the statements in my Direct Testimony with respect to the flaws in the equivalent peaker ("EP") method remain in force.

Q. Please explain further why the use of the EP method to classify and allocate production plant is inappropriate.

A. My arguments with respect to the EP method remain the same as in my Direct Testimony filed in Docket No. 05-UR-106. The problem with Mr. Singletary's use of the EP method is that it assumes, without foundation, that the costs of production plant greater than the cost of a combustion turbine are incurred by the utility for no reason other than to achieve fuel savings. The EP method generally calculates the percentage of production plant to be classified as “energy related” by subtracting the current cost of a combustion turbine unit from the cost of all non-peaking units on the system and calculating a ratio to the total cost of production plant. The “energy” portion of production plant is then allocated to WEPCO’s retail customer classes using a kWh energy allocator.

The problem with this approach is that there is no support for the method’s defining principle that the cost of the so-called “energy” portion of production plant was incurred to achieve fuel savings. Mr. Singletary provided no analysis or quantitative support for this assumption. For example, an economic screening curve analysis might show that the breakeven hours of operation between a coal unit and a combustion turbine (at today’s fuel costs) is 350 hours annually. Once a CT is shown to run more than 350 hours (under this hypothetical), the least cost capacity addition is a coal unit. What this means is that additional off-peak energy usage probably does not affect the decision to select a coal unit as the least cost resource addition; yet, under the EP method Staff assumed that this additional off-peak energy usage is responsible for the resource addition. Furthermore, it is likely that the kWh usage most responsible for the selection of the coal unit (that is, the kWh usage up to the breakeven hours of use) is kWh energy usage during a few hundred hours during the on-peak summer period. These are the kWh that are likely driving the decision to select that coal unit as the least cost resource addition; kWh usage in excess of this breakeven amount does not drive the decision.

Moreover, a relevant EP cost of service analysis requires an examination of economic analyses that were performed at the time of the decision making of each base load and intermediate load power plant on the WEPCO system. Mr. Singletary did not provide that supporting material. Without incorporating these historic analyses into the EP methodology, it is impossible to identify the "cost causation" underlying each unit and, in particular, the expected fuel savings that a base load coal or nuclear unit was likely to achieve. Since the premise behind the EP method is that expected fuel savings drove WEPCO's decision to construct a base load (or intermediate) generating unit in lieu of a less expensive peaking unit, the "decision" would have considered the capital cost of each unit and the fuel cost differences to the system between the two choices. The additional cost of a base load unit may not have been justified by fuel savings expectations alone. Rather, the decision may also have considered other factors (such as the longer life of a base load unit) which, when combined with fuel savings, justified the higher cost base load unit.

In conclusion, the results of Mr. Singletary's EP study should be rejected and his Scenario 3 CCOSS should be rejected as well.

Q. Please address Mr. Singletary's allocation of non-fuel production O&M using a 90% energy allocation.

A. Mr. Singletary's recommended 90% energy allocation of non-fuel production O&M is deeply flawed and should be rejected by the Commission.

According to the calculations presented in Schedule 10 of Ex.-PSC-Singletary-1, Mr. Singletary simply assumed that the portion of non-fuel O&M cost of non-peaking capacity that was greater than the non-fuel O&M cost of peaking capacity should be classified and allocated on an energy basis. There is absolutely no basis for this assumption. Fixed non-fuel production costs, whether or not they are related to peaking capacity, should not be treated the same as energy-related fuel costs. Variable O&M, which varies with kWhs consumed by WEPCO's customers, should be allocated based on energy consumption. However, fixed non-fuel costs should be classified and allocated on the same basis as production plant using the 4CP method. Mr. Singletary's recommended classification of non-fuel O&M costs does not even follow the results of his EP calculations for production plant. I strongly recommend that the Commission reject Mr. Singletary's unreasonable allocation on non-fuel production O&M costs.

Q. Please summarize the positions of Mr. Singletary and Mr. Wallach regarding the classification and allocation of WEPCO distribution plant.

A. At Direct-PSC-Singletary-10, Mr. Singletary explained that WEPCO "uses a minimum system approach" to allocate distribution costs. He further explained that "some analysts" believe that the minimum-size system employed by WEPCO overstates the allocation of customer-related costs. However, he did not indicate whether he, himself, was one such analyst that disagreed with WEPCO's approach. He does present arguments that some analysts make in support of a "location" approach, and points out deficiencies of that approach, but does not indicate whether he supports the approach. Ultimately, Mr. Singletary does not offer an opinion as to whether the "minimum system approach" or the "location" approach is most reasonable, nor whether both should be given equal weight by the Commission.

Mr. Wallach, though, objects to WEPCO's minimum-size approach beginning at Direct-CUB-Wallach-15.

Q. Would you explain the concept underlying the minimum system approach that the Company used to classify distribution plant and expenses between customer and demand components?

A. Yes. The principle supporting the minimum system approach, which includes a customer component, is that utilities must invest a minimal amount in distribution facilities to connect a customer to the distribution system (lines, poles, transformers) that is independent of the customer's level of demand. For example, there is a minimum amount of investment that a utility will make in poles, lines and transformers to connect a customer, whether that customer has a demand of 3 kW or a demand of 5 kW. This does not mean that the investment would be the same, but rather a minimum investment is required regardless of size. Under the minimum distribution system methodology, the minimum component is allocated on a per customer basis, while the portion of cost above minimum is allocated on demand. Thus, to the extent that the utility incurs a distribution cost simply to connect a customer to its system, regardless of that customer's size, it is appropriate to assign the cost of these minimal facilities to rate schedules 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.

I have included relevant pages from the NARUC Cost Allocation Manual as Ex.-WIEG-Baudino-3.

Q. Is the Company's use of a minimum system methodology consistent with the methods discussed in the NARUC manual?

A. Yes, it is. NARUC recognizes two methodologies for estimating the customer component of distribution costs. These methods, which are described in the NARUC manual, are the "minimum-intercept" method and the "minimum size" method (which is the same as the "minimum system" method). Each of the two methods captures customer-related costs and is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively connect a customer to its system, as opposed to providing a specific level of power (kW demand) to the customer. The conceptual basis for the minimum size method is that it reflects a classification of the distribution facilities that would be required to simply connect a customer to the system, irrespective of the customer's kW load. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities would be required simply due to the requirement to connect the customer.

The minimum-intercept (also referred to as zero-intercept) method seeks the same end as the minimum size system approach but is much more data intensive. This method estimates the portion of distribution plant that is related to a hypothetical no-load, or zero-load situation. This is the amount of plant that would be required to serve customers regardless of their demands. Typically, the zero-intercept method utilizes regression analysis to estimate the customer-related portion of distribution plant.

WEPCO's minimum system analysis uses a combination of minimum system and regression techniques to classify and allocate certain distribution accounts and is described in Mr. Rogers' Direct Testimony. This approach is reasonable and appropriate to use for purposes of classifying and allocating distribution costs in this proceeding and I recommend that the Commission adopt Mr. Rogers' classification and allocation of distribution costs.

Q. Mr. Wallach presented simplified examples in Figures 1a, 1b, 2a, and 2b purporting to show how the minimum size system fails to accurately classify and allocate distribution costs. Please address these examples provided by Mr. Wallach.

A. Mr. Wallach's simplistic examples fail to capture the system-wide application of the minimum system approach. Indeed, they also fail to recognize the underlying fact that certain distribution facilities are installed simply to connect customers to the system irrespective of the demands placed on that system. The minimum size approach provides a valid conceptual framework to estimate the customer-related portion of those facilities. If one were to simply use non-coincident demands to allocate the cost of those facilities larger commercial and industrial customers would be burdened with an excessive allocation of distribution system costs.

Mr. Wallach's simple examples in Figures 1a and 1b also fail to support his contention that the minimum distribution system approach allocates costs to customer classes as if costs vary with the number of customers. In fact, the total cost is the same in Figures 1a and 1b. If the minimum system shown in his Figure 1b can support additional residential customers, then what happens is that costs per customer decline even though the residential class is allocated a greater percentage of the costs of the minimum system.

In Figure 1b, note that the $80,000 of costs allocated to four residential customers results in a per customer cost of $20,000. This is *lower* than the per customer cost of $50,000 in Figure 1a. With a fixed cost, this is exactly what one would expect as more customers connect to the system. Mr. Wallach's example completely misses the point and fails to refute the value of the minimum size system approach.

Mr. Wallach's examples in Figure 2a and 2b do not accurately show how the minimum size system would be applied. Note that in Figure 2a Mr. Wallach shows a so-called minimum cost feeder that supports 130 kW of load. In this example, his so-called minimum cost feeder does not represent the customer-related portion of the feeder cost because it is capable of carrying 130 kW of load. Ideally, the minimum cost of the feeder would include the minimum or no-load customer-related portion of the feeder and be allocated to customers based on customer count. The portion that did carry the 130 kW of load would be classified as demand-related and allocated based on non-coincident demand.

Q. What is your recommendation with respect to CCOSS Scenario 4 presented by Mr. Singletary?

A. I recommend that the Commission reject CCOSS Scenario 4. Staff CCOSS Scenario 4 improperly classifies certain distribution accounts as 100% demand-related. For the reasons I presented earlier, I recommend that the Commission accept the Company's approach to the classification and allocation of distribution plant.

<u>Customer Class Revenue Allocation and Rate Design</u>

Q. Briefly summarize Staff's recommended revenue allocation to customer classes.

A. Staff's recommended revenue allocation is presented in the Direct Testimony of Mr. Albrecht. At Direct-PSC-Jerry Albrecht-3, Mr. Albrecht explains that his revenue allocation recommendation is based on the results of Staff's time-of-use ("TOU") and location CCOSS. The TOU CCOSS corresponds to Scenario 3 and the Location CCOSS corresponds to Scenario 4 as presented by Mr. Singletary in his Direct Testimony.

Q. What is your conclusion with respect to Mr. Albrecht's revenue allocation recommendations?

A. Since Mr. Albrecht based his revenue allocation proposal on Mr. Singletary's CCOSS Scenarios 3 and 4, the Commission should reject his revenue allocation. Staff's TOU and Location studies inaccurately and improperly allocate costs to customer classes because:

- The studies use a 12CP allocator for production demand costs.
- The studies partially classify production plant costs as energy-related.
- The studies classify 90% of fixed production O&M as energy-related.
- Scenario 4 does not follow WEPCO's classification and allocation of distribution plant.

Q. At Direct-PSC-Jerry Albrecht-8, Mr. Albrecht explains his approach to designing demand and energy charges. Please respond to Mr. Albrecht's rate design recommendation.

A. Mr. Albrecht's rate design should be rejected. For purposes of this proceeding, I recommend that the Commission adopt Mr. Rogers' rate design with respect to the structure of demand and energy charges. Mr. Roger's demand charges generally follow the marginal demand cost studies he presented. The energy rates he proposed are already greater than marginal energy costs and are designed to collect revenues not collected through demand charges. As I mentioned in my Direct Testimony, WEPCO's rate design already favors lower load factor customers since energy charges exceed marginal costs and, other things being equal, operates to the detriment of high load factor customers. It is for this reason that I continue to recommend that WEPCO file embedded demand and energy costs in its next rate case to provide additional guidance in rate design.

Real Time Market Pricing Rider

Q. Did Staff submit a report to the Commission regarding WEPCO's RTMP rider in this proceeding?

A. Yes. Mr. Singletary presented the results of a study performed by Staff beginning on Direct-PSC-Singletary-37.

Q. Did you review the study presented by Mr. Singletary?

A. I reviewed Mr. Singletary's testimony regarding the RTMP study, which contained a summary of the results of Staff's study. However, Mr. Singletary provided no documentation, statistical test results, or other work papers supporting this study. In particular, Mr. Singletary provided no information on the regression equations he used, no information on how his sample of non-RTMP customers was derived, and no information as to the statistical validity of his results. Therefore, it is not possible to fully respond to all of the analyses and conclusions that were contained in Mr. Singletary's testimony. WIEG has requested all supporting work papers and documentation for this study, but has not received a response from Staff as of the filing of my Rebuttal Testimony. Indeed, Staff has not yet even produced a copy of the study itself, which I would have expected to be available for review immediately. WIEG reserves the right to file additional testimony regarding this study after I have had an opportunity to review the discovery responses provided by Staff. However, I am able to provide a partial response to the results of Staff's RTMP study as presented by Mr. Singletary.

Q. What are your conclusions and recommendations with respect to the RTMP study provided by Mr. Singletary?

A. Staff's RTMP study fails to provide a complete analysis of WEPCO's and Wisconsin's experience with the RTMP tariff. Specifically, Staff's study suffers from the following serious flaws:

- Staff's study fails to include the economic benefits to the state of Wisconsin from the RTMP rider. Staff's study should be rejected on the basis of this serious omission alone.
- Mr. Singletary's definition of free ridership is completely incorrect. In fact, Staff's study did not show any free rider effect associated with the RTMP rider.
- Mr. Singletary's discussion of the Polar Vortex has absolutely no bearing on the effectiveness of the RTMP rider. In fact, Mr. Singletary showed that RTMP customers fully assumed the market risk of higher energy prices during January through March of 2014.
- Mr. Singletary's comparison of RTMP customer growth to a non-RTMP customer group is invalid and irrelevant with respect to the effectiveness of the RTMP program.
- Mr. Singletary failed to show any harm from the RTMP program to other ratepayers or to WEPCO shareholders, even though he suggested that the Commission consider these factors of Direct-PSC-Singletary-47.

- Mr. Singletary raised "discrimination concerns" in his list of considerations for the Commission, yet failed to show that any rate discrimination is taking place.

Q. Please provide a brief review of how the RTMP rider originated and eventually expanded.

A. On April 21, 2011 WEPCO filed an application with the Commission seeking approval of its RTMP rider. The Company stated the following on page 1 of its application:

> Wisconsin Electric Power Company d/b/a We Energies ("We Energies") hereby requests Commission approval of a new tariff rider called "Real-Time Market Pricing", or RTMP, that provides a market-priced service option for primary electric service customers.
>
> This rate is the result of on-going discussion with both individual customers as well as the Wisconsin Industrial Electric Group (WIEG). The aim is to provide a pricing option that offers the advantages of market pricing on incremental load. In exchange, participating customers will also be subject to market pricing risks that other ratepayers taking service under standard tariff rates do not face.
>
> This rider is specifically aimed at larger commercial and industrial customers that are recovering from periods of low energy consumption due to economic stress, or are existing customers projecting some growth or moving to a new facility with different energy needs, or are customers that may be new to We Energies' service territory. ***The rate has been carefully designed to provide this opportunity without disadvantaging other ratepayers that are not participating in this tariff rider.*** (emphasis supplied)

On August 11, 2011, the Commission approved the proposed RTMP with two modifications: a requirement that WEPCO restrict the availability of the RTMP tariff so that existing customers cannot relocate loads from elsewhere in Wisconsin to WEPCO's service territory in order to take advantage of the rate; and, a requirement that participating customers certify that they have implemented all energy efficiency measures that are economically efficient.

On February 23, 2012 WEPCO filed an application to expand the availability of the RTMP rider to Cp-3 General Primary Curtailable customers and to expand the maximum amount of customer load that can take service under the RTMP rider from 100 mW to 150 mW. On May 15, 2012 the Commission approved the requested amendments to the RTMP rider.

On July 31, 2013 WEPCO requested approval to expand the maximum amount of customer load eligible to take service under the RTMP rider from 150 mW to 300 mW. The Commission approved this request by a letter dated August 20, 2013. On August 26, 2013 CUB requested that the Commission rescind its approval and consider the issue at the Commissioner level after a Staff analysis was completed. This analysis was referenced in the Commission's Final Decision of August 11, 2011. As part of its analysis Staff sent out a report prepared by La Capra Associates for comment that was prepared on behalf of CUB. WEPCO and WIEG issued a response to the La Capra report showing that the RTMP was working "extremely well".[1] On September 24, 2013, the Commission issued its Order in Docket No. 6630-GF-134 approving the expansion of the RTMP rider and noted the following:

> While the Commission staff analysis provided for in the Final Decision of August 11, 2011, has not been completed, the information provided and reviewed by the parties is sufficient to support the current expansion request; the expansion request need not be delayed until the RTMP Rider analysis is completed. ***The RTMP Rider is working to expand electric demand and to create jobs***. (emphasis supplied)
>
> ***Further, no costs of the RTMP Rider are borne by non-participating customers***. The RTMP Rider is different from an economic development rate; it does not offer discounts from embedded cost rates. This tariff is structured so that the utility recovers all costs for load up to the customer's baseline, and all marginal costs for incremental load are recovered from the customer. The customer bears the risk of market prices for its incremental load. (emphasis supplied)

[1] For a full discussion, please refer to PSC REF#:190905.

Q. What are your conclusions with respect to the RTMP rider to this point?

A. In three separate Orders and/or decisions, the Commission found the RTMP to be just and reasonable and that it does not impose additional costs on non-participating customers. The Commission most recently found that the RTMP rider has been beneficial to the Wisconsin economy in terms of job creation. The Commission did not find the RTMP rider to be discriminatory. The Commission also approved two separate expansions of the RTMP program due to its successful track record. In my opinion, the Commission also thoughtfully moved to limit the potential of free riders when it first approved the RTMP rider in 2011.

I would also add that the RTMP has assisted Wisconsin industry located in WEPCO's service territory to mitigate industrial rates that are the highest in the state. All in all, the RTMP rider has been very beneficial. The Commission should approve the Company's proposed extension of the program for an additional three years.

Q. Does Staff's RTMP study provide a sound basis for the Commission to make a determination as to whether WEPCO's proposed continuation of the RTMP rider should be approved?

A. No, it does not. Most importantly, Staff's RTMP study omits any evaluation or discussion of the effect of the RTMP rider on Wisconsin's economy. Mr. Singletary points out this fact on Direct-PSC-Singletary-42, lines 10 through 13. In this respect, Staff's RTMP study fails to provide the Commission with critical information about the economic success of the RTMP rider. Both WEPCO and WIEG submitted comments in response to the La Capra study in 2013 showing significant economic benefits in terms of job growth from the RTMP program.[2] The Commission also agreed that the RTMP rider

[2] See PSC REF#:183769 for WEPCo's and WIEG's comments and PSC REF#:182010 for the La Capra study prepared on behalf of CUB.

had a positive impact on economic development in terms of job creation in its September 2013 Order. Staff's study failed to provide any additional updated information for the Commission's consideration.

It is important for the Commission to consider Staff's study showed no harm to other ratepayers. The Commission's past Orders have already determined that the RTMP rider is reasonable, does not shift costs to other ratepayers, and is economically beneficial. In addition, Staff's RTMP study supports certain aspects of the RTMP program, such as:

- RTMP customers accepted the risks of higher energy costs during the "Polar Vortex" event during January - March 2014.
- RTMP customers have expanded load in response to the RTMP rider.

Mr. Singletary's presentation has other serious problems that I will address subsequently. However, nothing in Staff's study suggests that the RTMP rider should not be extended for another three years as proposed by WEPCO.

Q. Beginning on Direct-PSC-Singletary-39, Mr. Singletary discussed purported free ridership on the RTMP rider. Do you agree with Mr. Singletary's finding of 18.1% of Incremental Energy Rate ("IER") mWh?

A. No. Mr. Singletary's definition of free ridership is completely incorrect. Mr. Singletary defines so-called free ridership along the same lines as CUB's La Capra report I cited earlier. Mr. Singletary defined free ridership as the difference between a customer's energy purchases made under the IER and that customers' actual monthly increase in energy sales over baseline energy levels.

However, WEPCO and WIEG's comments to the Commission in 2013 refuted that definition of free ridership. It is important to note that one of the primary objectives of the RTMP rider is to encourage customers to respond to market pricing signals and Mr. Singletary's flawed definition of free ridership overlooks this fact. The RTMP, like all time-of-use rates, provide incentives to customers to use power and energy more efficiently and to manage load into less expensive hours. As WEPCO and WIEG stated in their 2013 comments to the Commission:

> Customers tend to react to variable price signals by adjusting their usage in a way that better optimizes usage of generation and network capacity. Using market rates to price incremental load when the market prices are more variable than standard rate rates only enhances the incentive and potential benefits of using power efficiently -- at the point of lowest system demand and cheapest prices. For a program nearing 130 MW of pre-subscription average load, this load management incentive provides a notable benefit to all rate-payers, even if it were the only benefit of RTMP rate design. But it's not.

In fact, Staff's study more likely shows the effect of customer load management under the RTMP, not free ridership. Staff's conclusion regarding free ridership under the RTMP rider should be rejected.

Q. Please respond to Mr. Singletary's discussion on Direct-PSC-Singletary-41 regarding the Polar Vortex event.

A. Mr. Singletary reported that extremely cold weather experienced during January through March of 2014 caused spikes in the MISO LMPs, in turn causing RTMP customers to pay more for new usage during this period. Mr. Singletary's study found that 20 RTMP customers were affected by the Polar Vortex and paid higher rates under the RTMP rider than they would have paid under standard rates.

Staff's finding supports one of the pillars of the RTMP regarding customers accepting the risk of market prices being higher than tariff prices. I disagree with Mr. Singletary's testimony that these losses were somehow offset with savings in subsequent months. Lower market pricing under the normal operation of the RTMP rider does not somehow offset higher prices in other months. The fact remains that 20 RTMP customers were affected by higher market prices from January through March 2014 according to Staff's study. This was part of the agreement customers entered into with the RTMP rider. I recommend that the Commission disregard Mr. Singletary's suggestion that higher costs to RTMP customers were somehow made up for by savings later in the year.

Q. On Direct-PSC-Singletary-42, Mr. Singletary presents a comparison of customer growth under the RTMP rider with a sample of non-RTMP customers. Is Mr. Singletary's comparison valid?

A. Mr. Singletary's comparison is neither valid nor relevant and I recommend that the Commission reject it.

Mr. Singletary stated on Direct-PSC-Singletary-42, lines 13 through 15 that RTMP growth rates can be compared with non-RTMP customer growth rates "to determine whether the RTMP is at least encouraging higher growth than would be experienced without the rate." This sort of comparison does not provide a valid basis for measuring the effectiveness of the RTMP rider. As Staff's study shows, RTMP customers did in fact increase their demand and energy usage over baseline levels, which is enough to show that the RTMP program is working as it should. It was never the original intention of the RTMP rider to somehow result in customer growth greater than the growth experienced without the RTMP. One should not infer from Staff's comparison that RTMP customers would have increased their demand and energy usage without the RTMP. The fact is that RTMP customers signed on to the Commission-approved rider and responded as expected. Any comparison to non-RTMP customers is irrelevant.

Q. Beginning on Direct-PSC-Singletary-46, Mr. Singletary listed a number of items that the Commission may wish to consider regarding WEPCO's requested continuation of the RTMP program. Please respond to Mr. Singletary's list of considerations.

A. Most importantly, Mr. Singletary failed to mention any consideration with of the economic benefits provided by the RTMP, which the Commission itself acknowledged in its September 2013 Order. He also failed to mention considering the potential economic harm to Wisconsin industry and employment if the RTMP program was not extended. I strongly recommend that the Commission approve the continuation of the RTMP. The ongoing economic benefits from this program, along with the fact that other ratepayers are not harmed by the RTMP, provide a sound basis for the Commission approving the continuation of the RTMP rider as proposed by WEPCO.

Second, Mr. Singletary also cited "discrimination concerns" on line 17 of Direct-PSC-Singeltary-46. I believe it is highly unlikely that the Commission would have approved the RTMP in the first place if it thought that the RTMP was unduly discriminatory. Mr. Singletary also did not cite the source of any such concerns, so there is really no foundation for his testimony on this point.

Third, Mr. Singletary asked how long is it reasonable for a customer to continue under that RTMP without a new contract and a new baseline. CUB witness Wallach went even further and recommended that the Commission order new baselines for RTMP customers on Direct-CUB-Wallach-33. However, I would ask Mr. Singletary to consider why continuation of the original baselines is unreasonable. Staff has shown no economic harm from the operation of the RTMP rider with the original customer baselines. Thus, there is no harm in continuing the existing baselines for RTMP customers. If current RTMP customers were required to provide higher baselines, this would likely end their participation in the RTMP program as these customers have probably already expanded all they can.

Q. Is continuing the RTMP consistent with the Commission's September 24, 2013 Order in 6630-GF-134?

A. Yes. On the date of that Order the Commission confirmed the approved of an expansion of the RTMP from 150 mWs to 300 mWs. It has only been approximately one year since the Commission's Order and in my opinion, WEPCO's requested three-year extension of the RTMP is consistent with that Order. It provides for ongoing benefits of the program to existing customers and the continued opportunity for additional customers to take advantage of the RTMP program.

Q. Does that complete your Rebuttal Testimony?

A. Yes.

Docket No. 05-UR-107

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1] Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

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.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.

   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.

   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.

   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.

   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (l/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.
  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.
  - Balance of cable investment is assigned to demand.
  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.
  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).
  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.
  - Multiply zero intercept cost by total number of line transformers to get customer component.
  - Balance of transformer investment is assigned to demand component.
  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

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Via Overnight Mail

December 18, 2014

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission v. West Penn Power Company
Docket No. R-2014-2428742 and C-2014-2442667

Dear Secretary Chiavetta:

Please find enclose the original and one (1) copy of the REBUTTAL TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION for filing in the above-captioned proceeding.

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place this document of file.

Respectfully submitted,

David F. Boehm, Esq. (PA Attorney I.D. # 72752)
BOEHM, KURTZ & LOWRY

COUNSEL FOR AK STEEL CORPORATION

DFBkew
Enclosure
cc: Certificate of Service
ALJ Dennis J. Buckley – debuckley@pa.gov
ALJ Katrina Dunderdale - kdunderdal@pa.gov
Pa. Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

REBUTTAL TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL CORPORATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 18, 2014

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO
ON BEHALF OF AK STEEL

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 to Kennedy and Associates.

Q. Did you submit Direct Testimony in this proceeding?

A. Yes. I submitted Direct Testimony on behalf of AK Steel Corporation.

Q. What is the purpose of your Rebuttal Testimony?

A. First, I will update my class cost of service study ("CCOSS") and revenue allocation proposals I submitted in my Direct Testimony. Second, I will respond to the CCOSS and revenue allocation testimony filed by Mr. Clarence L. Johnson, witness for the Pennsylvania Office of Consumer Advocate ("OCA"); Mr. Robert Knecht, witness for the Pennsylvania Office of Small Business Advocate ("OSBA"); and Mr. Kokou Apetoh, witness for the Bureau of Investigation and Enforcement ("BIE").

I. REVENUE ALLOCATION

Q. Did West Penn Power Company ("WPP" or "Company") provide a corrected CCOSS in response to discovery in this proceeding?

A. Yes. WPP provided a fully corrected version of West Penn Exhibit HES-1 in its response to AK Steel Set IV, No. AK-Q.4-4, Attachment A. This revised CCOSS provided all corrections to the admitted errors that I identified in my Direct Testimony, including the error I identified on page 16, lines 7 through 12. I was unable to quantify that error due to insufficient information at the time I filed my Direct Testimony. As I noted in my Direct Testimony, correcting this error would have the effect of shifting some cost responsibility from secondary voltage customers to primary voltage customers.

Q. Did you prepare a revised AK Steel CCOSS?

A. Yes. Using WPP's corrected version of West Penn Exhibit HES-1, I revised my recommended AK Steel CCOSS. Rebuttal Exhibit No. ___(RAB-1) provides a summary of the results of my revised AK Steel CCOSS with my proposed 50% reduction in current subsidies. This CCOSS includes all six admitted errors by the Company and my recommended corrected allocation of substations. Rebuttal Table 1 below presents revised class rates of return and recommended revenue increases. Although some cost responsibility shifted to the PP46 class in the revised AK Steel CCOSS, the results still show that PP46 is paying rates that are significantly higher than its allocated cost to serve and should receive no increase in this case.

Rebuttal Table 1
Revised AK Steel CCOS Summary
($000s)

	Current ROR	Relative ROR	Adjusted Increase	Pct. Increase
RS	3.11%	0.69	$71,024	34.8%
GS10	12.67%	2.80	$0	0.0%
GSS	-3.79%	(0.84)	$4,301	37.5%
GSM	15.45%	3.41	$0	0.0%
PP40	4.28%	0.95	$1,383	20.3%
GSL	12.60%	2.78	$0	0.0%
POL	18.25%	4.03	$0	0.0%
PSU	13.37%	2.95	$0	0.0%
PP44	-7.42%	(1.64)	$36	130.5%
PP46	14.23%	3.14	$0	0.0%
AGS	2.15%	0.47	$6	38.0%
STLT	3.62%	0.80	$1,873	31.1%
Total Retail	4.53%	1.00	$78,623	25.0%

Consistent with my position in my Direct Testimony, I mitigated the increase to Rate GSS by limiting its increase to 1.5 times the system average increase of 25.0%. The balance of the revenue increase that GSS would have received with a 50% reduction in its current revenue subsidy was shifted to Rate RS. Note that after this shift, both Rates RS and GSS would still be receiving subsidies from other customer classes.

Q. Do you also provide an updated corrected WPP CCOSS based on the Company's preferred CCOSS?

A. Yes. Please refer to Rebuttal Exhibit No. ___(RAB-2) for a summary of the results of the corrected WPP CCOSS using its preferred allocation method and with my proposed 50% reduction in current subsidies. Rate PP46 would receive a higher increase (29.2%) due to incorporating all the known CCOSS corrections that I described earlier in my Rebuttal Testimony. Also note that I limited the increase to Rate PP40 to 1.5 times the system average increase and shifted the balance of its increase to Rate RS. This is the same approach I used in my Direct Testimony for GSS. However, due to the increased cost responsibility for primary customers in the Company's corrected CCOSS, Rate PP40's percentage increase was larger than it was in my Direct Testimony. Thus, Rate PP40 required mitigation to its percentage increase to 1.5 times the system average increase.

Q. Mr. Baudino, does the class revenue allocation recommendation in Rebuttal Table 1 represent your final position?

A. No, not necessarily. As of the date I prepared this testimony, WPP has not provided its final position with respect to CCOSS and revenue allocation. I will provide further response and analysis in my Surrebuttal Testimony based on what WPP provides with respect to CCOSS and revenue allocation in its Rebuttal Testimony.

II. RESPONSE TO PARTIES' CCOSS TESTIMONIES

<u>**Response to OCC witness Johnson**</u>

Q. On page 10 of his Direct Testimony, Mr. Johnson testified that the minimum distribution plant concept is "inherently flawed and fails to reflect cost causation." Does the minimum system concept reflect cost causation?

A. Yes, it does. Mr. Johnson's assertion regarding the minimum system approach should be rejected.

Q. Please explain how distribution costs are incurred.

A. Distribution costs are incurred to meet customer demands on the distribution system, as well as the minimum requirements to simply provide an interconnection to a customer (minimum system costs). The Electric Utility Cost Allocation Manual ("Manual"), January 1992, published by the National Association of Regulatory Utility Commissioners ("NARUC") discusses methodologies adopted by the industry and regulators to allocate and recover the cost of distribution facilities. These methodologies recognize that the cost incurred to provide distribution service is a fixed cost and should be allocated on the basis of one or more demands (for example, customer maximum demands, class diversified demand) and on the basis of the number of customers taking distribution service on the rate schedule.

Q. Would you explain the concept underlying the minimum size approach that the Company used to classify distribution plant and expenses between customer and demand components?

A. Yes. As described in the NARUC Manual, the underlying argument in support of the minimum system approach, which includes 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. To the extent that this component of distribution cost is a function of the requirement to interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules 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 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. Is the Company's use of a minimum grid methodology consistent with the accepted methods discussed in the NARUC manual?

A. Yes, definitely. There are two recognized methodologies to estimate the customer component of distribution costs. These methods, which are described in the excerpt from the NARUC manual, are the "minimum intercept" method and the "minimum size" method, which is similar to the approach used by WPP. 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.

A minimum size distribution cost of service analysis is designed to reflect the costs associated with changes in both the number of distribution customers and the loads of these customers. The conceptual basis for the minimum size method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities would be required simply due to the requirement to interconnect the customer.

Q. On page 11 of his Direct Testimony, Mr. Johnson recommended that Accounts 364 - 368 be classified as 100% demand related. Please respond to this recommendation.

A. Based on the foregoing discussion, Mr. Johnson's recommended classification of Accounts 364 - 368 should be rejected. Classifying these accounts solely on the basis of demand would result in an unwarranted shift in cost responsibility from residential customers to the larger customer classes, such as Rate PP46. I recommend that the Commission adopt and approve WPP's recommended classification of these accounts.

Q. On page 26 of his Direct Testimony, Mr. Johnson recommends that uncollectible expenses be allocated based on class revenues. Please respond to this recommendation.

A. The Commission should reject Mr. Johnson's recommended allocation of uncollectible expenses. Mr. Johnson presented no evidence or support whatsoever that the percentage of uncollectible expenses follows each class' percentage of distribution revenues. In my experience, the vast majority of uncollectible expenses is attributable to the residential class of customers. Thus, it is reasonable for the Company to allocate these expenses based on the number of customers.

Q. On page 29 of his Direct Testimony, Mr. Johnson recommended allocating Account 908, Customer Assistance and Information Expenses, on the basis of class revenues. Please respond to this recommendation.

A. The Commission should reject Mr. Johnson's recommended allocation of expenses in Account 908 and accept WPP's proposed allocation. Account 908 costs are classified as customer related and should be allocated on that basis. The types of costs identified by Mr. Johnson on pages 28 and 29 of his testimony are certainly customer related and are likely all attributable to residential customers, not to larger customers and certainly not to Primary service customers. On page 29, lines 6 through 12, Mr. Johnson suggested that "some" expenses included in Account 908 might be directed toward non-residential customers, but he failed to identify the amount of any such alleged costs. Certainly, Mr. Johnson did not tie the responsibility for Account 908 costs to each class' revenue percentage.

Q. On page 31 of his Direct Testimony, Mr. Johnson recommended allocating Account 910, Miscellaneous Customer Information Expenses, 50% on the basis of revenues and 50% on a customer basis. Please address Mr. Johnson's recommendation.

A. The Commission should reject Mr. Johnson's recommended allocation of Account 910 expenses. Once again, these expenses are totally customer related and should be allocated on that basis. The Company's weighted customer allocation should be adopted since it is based on a weighted percentage of call center calls attributable to particular customer classes. Using class revenues as an allocator would unfairly shift these costs toward non-residential customer classes.

Q. Mr. Johnson recommended that the Commission accept his revised CCOSS as summarized in his Schedule CJ-5. What is your recommendation with respect to Mr. Johnson's recommended CCOSS?

A. The Commission should reject Mr. Johnson's proposed CCOSS. It inappropriately shifts substantial cost responsibility from the Residential class to other rate classes. This is due primarily to his rejection of the Company's minimum grid study and the classification of costs in Accounts 364 - 368 as 100% demand related. Mr. Johnson's shifting of customer-related costs in Accounts 908, 910, and uncollectible expenses was also unjustified and served to allocate cost responsibility to customer who are not responsible for those costs. Finally, Mr. Johnson's CCOSS is based on the inappropriate classification and allocation of substations, which I identified and explained in my Direct Testimony. Thus, Mr. Johnson's CCOSS allocates excessive cost responsibility for substations to customers in the primary rate classes.

Likewise, the Commission should reject Mr. Johnson's proposed revenue allocation approach since it relies on his revised CCOSS.

<u>**OSBA Witness Knecht**</u>

Q. On page 15, lines 12 through 14 of his Direct Testimony, Mr. Knecht testified that the differences between WPP's filed CCOSS and his estimated corrected

CCOSS "relatively modest, and do not change the directional implications for revenue allocation." Please address this conclusion.

A. In fact, Mr. Knecht's Table IEc-5 on page 16 of his testimony shows a substantial difference in the class rate of return for Rate 46, which goes from a -0.8% return to a 3.2% return. This is not a modest change for Rate 46 customers. I would agree with Mr. Knecht's conclusion with respect to the other rate classes.

Q. On page 23 of his Direct Testimony, Mr. Knecht presents Table IEc-8, which shows his revenue allocation proposal for WPP. Does there appear to be a problem with this table?

A. Yes. The notes to Table IEc-8 state that the class rates of return are based on Mr. Knecht's estimate of the corrected version of WPP's CCOSS. However, the class rates of return shown in this table are from WPP's uncorrected CCOSS. Rate 46 shows a rate of return of -0.8% in Table IEc-8, whereas Mr. Knecht had estimated a corrected rate of return of 3.2% for Rate 46. It is does not appear that the rate increase shown by Mr. Knecht follows his estimated corrected CCOSS.

Q. Does the CCOSS upon which Mr. Knecht relied allocate excessive substation costs to primary customers?

A. Yes. Mr. Knecht's revenue allocation proposals are based off of WPP's faulty CCOSS, which incorrectly classifies and allocates the costs of substations as I explained in my Direct Testimony. As a result, Mr. Knecht allocates too much cost and revenue responsibility to primary voltage customers.

<u>Response to BIE witness Apetoh</u>

Q. Could you please comment on Mr. Apetoh's revenue allocation recommendation?

A. Yes. Mr. Apetoh's revenue allocation is based on WPP's flawed and admittedly incorrect CCOSS. This CCOSS also overstates the cost responsibility of Primary service customers for substation costs, as I explained in my Direct Testimony. Mr. Apetoh's revenue allocation cannot be used in its present form to properly allocation WPP's proposed revenue increase to customer classes.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket Nos. R-2014-2428742
	:	C-2014-2442667
West Penn Power Company	:	

AFFIDAVIT OF RICHARD A. BAUDINO

STATE OF GEORGIA)
COUNTY OF FULTON)

Richard A. Baudino being first duly sworn, deposes and states that:

1. He is a consultant with J. Kennedy & Associates, Inc.;

2. He is the witness who sponsored the testimony entitled "Rebuttal Testimony and Exhibits of Richard A. Baudino" on behalf of AK Steel Corporation.

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and exhibits are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Subscribed and sworn to or affirmed before me this 5TH day of December, 2014 by Richard A. Baudino.

LANE KOLLEN
MY COMMISSION EXPIRES
NOTARY PUBLIC
DECEMBER 9, 2016
COBB COUNTY, GEORGIA

Notary Public

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

REBUTTAL EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 18, 2014

Rebuttal Exhibit No. ___(RAB-1)

AK STEEL REVISED CCOSS
Recommended Revenue Allocation
($000s)

	TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL	POL	PSU	PP44	PP46	AGS	STLT
Rate Base Total	1,287,297	939,652	1,231	89,144	137,302	23,682	49,405	8,795	2,742	233	5,725	73	29,313
Tariff Revenue Total	314,652	204,009	494	11,475	59,237	6,829	19,107	3,945	1,084	28	2,399	15	6,031
Other Revenue Total	14,431	10,859	13	1,248	1,224	267	390	69	30	3	66	1	261
Retail Total Revenue	329,083	214,868	507	12,723	60,462	7,096	19,498	4,014	1,113	31	2,465	15	6,291
Total Operating Expense	229,881	165,668	240	18,436	24,147	5,272	8,822	1,304	473	59	1,046	13	4,401
Total Income Tax	40,926	19,982	111	(2,338)	15,107	811	4,450	1,105	274	(11)	604	1	828
Net Income After Tax - Present Rates	58,276	29,217	156	(3,375)	21,207	1,014	6,225	1,605	366	(17)	815	2	1,062
Rate of Return - Present Rates	4.53%	3.11%	12.67%	-3.79%	15.45%	4.28%	12.60%	18.25%	13.37%	-7.42%	14.23%	2.15%	3.62%
Subsidy at Present Rates	(0)	24,197	(182)	13,461	(27,230)	106	(7,245)	(2,192)	(440)	51	(1,009)	3	481
Increase to Equal ROR - Requested	78,623	81,587	(107)	18,905	(18,844)	1,552	(4,227)	(1,655)	(273)	65	(659)	8	2,271
Less: Remaining Subsidy	0	(12,098)	91	(6,730)	13,615	(53)	3,622	1,096	220	(25)	505	(2)	(241)
Increase at 50% Subsidy Reduction	78,623	69,489	(16)	12,175	(5,229)	1,499	(605)	(559)	(53)	39	(155)	6	2,031
Eliminate Rate Decreases	-	(5,394)	16	(945)	5,229	(116)	605	559	53	(3)	155	(0)	(158)
Adjusted Increase	78,623	64,095	-	11,230	-	1,383	-	-	-	36	-	6	1,873
Adjustment to Limit GSS to 1.5 times Avg.	78,623	71,024	-	4,301	-	1,383	-	-	-	36	-	6	1,873
Company Proposed Increases	78,623	60,825	137	4,544	3,512	6,147	734	2,131	401	99	1,921	23	(1,852)
Subsidy at Company Proposed Rates	0	20,762	(244)	14,361	(22,356)	(4,595)	(4,961)	(3,786)	(674)	(34)	(2,581)	(16)	4,123
% Subsidy Reduction - Company Proposed		14.2%	-33.9%	-6.7%	17.9%	4430.2%	31.5%	-72.7%	-53.2%	168.0%	-155.8%	604.9%	-757.0%
Percent Increase - 50% Subs Red	25.0%	34.1%	-3.2%	106.1%	-8.8%	22.0%	-3.2%	-14.2%	-4.9%	141.5%	-6.5%	41.2%	33.7%
Adjusted Percent Increase	25.0%	31.4%	0.0%	97.9%	0.0%	20.3%	0.0%	0.0%	0.0%	130.5%	0.0%	38.0%	31.1%
Adjustment to Limit GSS to 1.5 times Avg.	25.0%	34.8%	0.0%	37.5%	0.0%	20.3%	0.0%	0.0%	0.0%	130.5%	0.0%	38.0%	31.1%

Rebuttal Exhibit No. ___(RAB-2)

WPP PREFERRED CCOSS
Revenue Allocation with
50% Subsidy Reduction and Mitigation

	TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL	POL	PSU	PP44	PP46	AGS	STLT
Rate Base Total	1,287,297	929,224	1,195	88,736	132,195	36,991	47,061	8,738	2,399	464	11,005	72	29,216
Tariff Revenue Total	314,652	204,009	494	11,475	59,237	6,829	19,107	3,945	1,084	28	2,399	15	6,031
Other Revenue Total	14,431	10,752	13	1,244	1,172	403	366	68	26	6	120	1	260
Retail Total Revenue	329,083	214,761	507	12,719	60,410	7,232	19,474	4,013	1,110	33	2,519	15	6,290
Total Operating Expense	229,881	164,188	235	18,378	23,422	7,161	8,489	1,296	424	92	1,795	13	4,387
Total Income Tax	40,926	20,518	113	(2,317)	15,370	126	4,571	1,108	291	(23)	333	1	833
Net Income After Tax - Present Rates	58,276	30,055	159	(3,342)	21,617	(56)	6,414	1,610	394	(36)	391	2	1,070
Rate of Return - Present Rates	4.53%	3.23%	13.29%	-3.77%	16.35%	-0.15%	13.63%	18.42%	16.43%	-7.73%	3.55%	2.20%	3.66%
Subsidy at Present Rates	(0)	21,818	(190)	13,368	(28,395)	3,143	(7,780)	(2,205)	(519)	103	196	3	459
Increase to Equal ROR - Requested	78,623	78,571	(117)	18,787	(20,321)	5,402	(4,905)	(1,672)	(372)	132	868	7	2,243
Less: Remaining Subsidy	0	(10,909)	95	(6,684)	14,198	(1,571)	3,890	1,103	259	(52)	(98)	(2)	(230)
Increase at 50% Subsidy Reduction	78,623	67,662	(22)	12,103	(6,124)	3,831	(1,016)	(569)	(113)	80	770	6	2,014
Eliminate Rate Decreases	(0)	(6,137)	22	(1,098)	6,124	(347)	1,016	569	113	(7)	(70)	(1)	(183)
Adjusted Increase	78,623	61,525	-	11,006	-	3,483	-	-	-	73	700	5	1,831
Adj. to Limit GSS, PP40 to 1.5 times Avg.	78,623	69,153	-	4,301	-	2,559	-	-	-	73	700	5	1,831
Company Proposed Increases	78,623	60,825	137	4,544	3,512	6,147	734	2,131	401	99	1,921	23	(1,852)
Subsidy at Company Proposed Rates	0	17,746	(254)	14,243	(23,833)	(745)	(5,639)	(3,802)	(773)	33	(1,054)	(16)	4,095
% Subsidy Reduction - Company Proposed		18.7%	-33.6%	-6.6%	16.1%	123.7%	27.5%	-72.4%	-49.2%	68.5%	639.0%	621.7%	-792.1%
Percent Increase - 50% Subs Red	25.0%	33.2%	-4.5%	105.5%	-10.3%	56.1%	-5.3%	-14.4%	-10.4%	286.5%	32.1%	40.8%	33.4%
Adjusted Percent Increase	25.0%	30.2%	0.0%	95.9%	0.0%	51.0%	0.0%	0.0%	0.0%	260.5%	29.2%	37.1%	30.4%
Adj. to Limit GSS, PP40 to 1.5 times Avg.	25.0%	33.9%	0.0%	37.5%	0.0%	37.5%	0.0%	0.0%	0.0%	260.5%	29.2%	37.1%	30.4%

CERTIFICATE OF SERVICE

I hereby certify that on this 18TH day of December, 2014 I served a true and correct copy of the REBUTTAL TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION on the following persons in the matter specified in accordance with the requirements of 52 Pa. Code §1.54.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2014-2406274**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

REBUTTAL TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE COLUMBIA INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.

JULY 2014

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2014-2406274**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

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 to Kennedy and Associates.

Q. Did you submit Direct Testimony in this proceeding?

A. Yes, I submitted Direct Testimony on behalf of the Columbia Industrial Intervenors ("CII").

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimonies of Mr. Glenn Watkins, witness for the Office of Consumer Advocate ("OCA"), Mr. Robert Knecht, witness for the Office of Small Business Advocate ("OSBA"), and Mr.

Jeremy Hubert, witness for the Bureau of Investigation and Enforcement ("I&E"). My Rebuttal Testimony will focus on certain issues relating to the cost and revenue allocation proposals set forth in the Direct Testimony of each of these witnesses. My Rebuttal Testimony will not address all issues raised in the Direct Testimony of these witnesses and, therefore, should not imply that I agree with the witnesses' positions on those issues. My Rebuttal Testimony will focus instead on the key issues discussed in the following sections.

__Class Cost of Service Studies__

Q. Briefly summarize the positions of the witnesses with respect to class cost of service studies ("CCOSS").

A. Messrs. Hubert and Watkins support the Peak and Average ("P&A") class cost of service study ("CCOSS"). Mr. Knecht utilized CCOSS results that were weighted 75% P&A and 25% Customer/Demand ("CD").[1] On page 15 of his Direct Testimony, Mr. Knecht explained that this weighting would likely approximate the results of his independent CCOSS approach from Columbia's last rate proceeding and is conceptually similar to the Average and Excess methodology that, according to Mr. Knecht, has been approved by the Pennsylvania Public Utility Commission ("Commission") for gas distribution utilities.

[1] By contrast, Columbia utilized results that were weighted 50% P&A and 50% CD.

Q. **Do you agree with Mr. Watkins' and Mr. Hubert's support of the Company's P&A CCOSS?**

A. No, I do not. For the reasons I stated in my Direct Testimony, the P&A CCOSS method is not appropriate due to the large amount of fixed distribution main cost that is classified and allocated on the basis of throughput.

Q. **Are you aware of any evidence or studies to support the assumption under the P&A CCOSS that a 50%-50% split of demand and commodity factors is representative of cost causation for gas distribution mains?**

A. No. The 50%-50% demand/commodity split is unsupported by any witness in this proceeding and appears to be based solely on judgment.

Q. **Please comment on Mr. Knecht's proposed use of blended CCOSS results that weight P&A by 75% and CD by 25%.**

A. First, I agree with Mr. Knecht's testimony on page 8 where he states that gas distribution mains are installed to: (1) connect the customer with the interstate pipeline system (or other gas supply resources) and (2) to transport gas sufficient to meet the demand of customers downstream under peak conditions. These two basic objectives strongly support a CD CCOSS, which recognizes both customer and peak demand components in the classification and allocation of gas distribution mains.

Second, these two causes for the installation of gas distribution mains do not support a 75% weighting of P&A CCOSS results. Yearly throughput is not a major factor, but connecting customers to the system and ensuring capacity to meet peak winter demands certainly are the major factors.

Q. On page 9, lines 12 through 16, Mr. Knecht pointed out that recent Commission precedent for electric distribution utilities strongly supports the recognition of a customer component for joint-use distribution plant allocation. Please respond to Mr. Knecht's testimony on this point.

A. If the Commission recognizes a customer component in the allocation of certain distribution plant, then in my opinion it would be reasonable and consistent to recognize a customer component for gas distribution mains. Indeed, there is a certain minimum investment that must be made in electric distribution facilities just to connect customers to the system regardless of their demands on the system. The use of a minimum size system approach by Columbia seeks to identify that customer related portion of investment in gas distribution mains in its CD CCOSS. In other words, I believe that Columbia is already recognizing the customer component in joint-use distribution plant allocation in its CD CCOSS.

Q. On page 39, lines 1 through 6, Mr. Hubert testified that since mains are not included in the definition of "direct customer costs" they should not be classified as customer costs. Please address Mr. Hubert's testimony on this point.

A. Mr. Hubert is incorrect. Although mains are not included in the strict definition of direct customer costs, this does not mean that they do not have a customer related component. I have described in my Direct Testimony how a portion of gas distribution mains are indeed related to the number of customers on the system and should, therefore, be partially classified and allocated on the basis of customers.

<u>**Class Revenue Allocation**</u>

Q. Please summarize the revenue allocation recommendations of Mr. Watkins, Mr. Hubert, and Mr. Knecht.

A. Mr. Watkins and Mr. Hubert base their revenue allocation proposals on the P&A CCOSS. Mr. Hubert presented the results of the Company's revenue allocation proposal on page 41 of his Direct Testimony. Although he did not appear to specifically endorse the Company's revenue allocation proposal, Mr. Hubert discusses movement in the class relative rates of return on page 42 of his Direct Testimony and recommended that the Commission consider movements in relative rates of return when establishing proposed rates.

Mr. Watkins presented his revenue allocation proposal on pages 27 and 28 of his Direct Testimony. Mr. Watkins explained on page 28 that he limited the increase to LDS full tariff customer to 1.50 times the system average increase in full tariff revenues, which Mr. Watkins calculated to be 18.94%. According to Mr. Watkins, this recommendation reduced the LDS class revenue responsibility by $85,000 from Columbia's proposal.

Mr. Knecht presented his revenue allocation proposal on pages 15 through 17 of his Direct Testimony. Table IEc-3 on page 17 shows how Mr. Knecht allocated the revenue increase requested by Columbia. Mr. Knecht based his recommendation on a weighted CCOSS that I described earlier. Mr. Knecht then reallocated LDS and MDS adjustments based on non-flexed volumes. His recommended increase for the LDS full tariff customers is $3.59 million, or 36.3%. Mr. Knecht explained on page 16 that his proposal limited any class' increase to two times the system average increase.

Q. Please respond to these witnesses' revenue allocation proposals.

A. I recommend that the Commission reject the revenue allocation proposals of Mr. Watkins, Mr. Hubert, and Mr. Knecht. Since Mr. Watkins and Mr. Hubert support the P&A CCOSS, their revenue allocation presentations allocate far too much cost and revenue responsibility to the LDS class. Likewise, although Mr. Knecht based his revenue allocation recommendation partly on the CD CCOSS, the 75% weighting of the P&A CCOSS still allocates an excessive amount of cost responsibility to LDS customers.

I continue to maintain my support of the CD CCOSS method as the most appropriate basis for cost and revenue allocation in this proceeding.

Q. Please address Mr. Hubert's discussion of class rates of return on page 42 of his Direct Testimony.

A. Mr. Hubert's discussion of class rates of return failed to include any consideration of the fact that 47.6% of LDS volumes are discounted subject to flex rate agreements with Columbia. Thus, the overall return and relative rate of return for the LDS class in the P&A CCOSS he supports is meaningless. At this point, there is no accurate measure in any CCOSS of the rate of return for the full tariff LDS customers.

Q. **What is the rate allocation increase Mr. Hubert is proposing for Rate LDS?**

Mr. Hubert's Direct Testimony does not provide a recommended percentage increase for the Rate LDS class. Additionally, Mr. Hubert's Direct Testimony does not take a clear position with respect to the exact revenue allocation supported by the OCA. Although Mr. Hubert recommended the P&A CCOSS, he did not specifically recommend that the Commission adopt the revenue allocation resulting from the Columbia's P&A CCOSS.

With that being said, because Mr. Hubert endorsed the P&A CCOSS and its resulting revenue allocation, his discussion of class rates of return raises significant concerns given that Columbia's P&A CCOSS fails to account for the impact of flexed rate volumes on the LDS class rate of return. If there is no consideration of the impact of flexed revenues on the LDS class' rate of return, then it may appear that the full tariff LDS customers could be assigned the entire revenue shortfall from the LDS class.

Q. **Should the cost of service revenue shortfall from flexed LDS contracts be assigned solely to the full tariff LDS customers?**

No, this approach would be completely inappropriate. Flexed contracts benefit Columbia's entire system and all customers. Thus, any revenue shortfall resulting from these agreements should therefore be spread across all customer classes.

Q. **On page 52 of his Direct Testimony, Mr. Hubert described a revenue scale back proposal in which the first $6.0 million reduction from Columbia's requested revenue requirement be used to reduce the increase to residential customers. Is this proposal reasonable?**

A. No, it is not. There is no good reason to treat the residential customers differently from the other customer classes with respect to a scale back from Columbia's filed revenue increase request. Any scale back approach should be in proportion to the percentage reduction from Columbia's request in which all classes receive equal percentage reductions. This does not mean that I endorse the Company's revenue allocation proposal. Rather, it is the principle of treating all customer classes equally with respect to a revenue scale back that I support.

Q. **On page 28 of his Direct Testimony, Mr. Watkins testified that the Company's weather normalization adjustment ("WNA"), which only applies to residential customers, makes residential customers less risky to serve. Mr. Watkins concluded that the required rate of return for residential customers is less than the required return for commercial and industrial classes. Do you agree?**

A. No, Mr. Watkins is incorrect. Mr. Watkins overlooked the fact that larger commercial and industrial customers are far less weather sensitive than residential customers. As I showed in Table 1 in my Direct Testimony, the heating loads of residential customers cause their usage to substantially fluctuate between heating and non-heating seasons. The monthly average consumption for industrial customers shows little variation between heating and non-heating seasons. This is why these customers do not require a WNA. Mr. Watkins missed this important point and his testimony regarding residential customers being less risky due to the WNA should be rejected.

Q. On page 28 of his Direct Testimony, Mr. Watkins testified that he limited the LDS full tariff revenue to 150% of the system average increase in full tariff revenues. Please address Mr. Watkins' proposal.

A. Mr. Watkins' revenue allocation proposal actually increases the LDS full tariff customers' revenues by $3.036 million, or 30.9%. This is because Mr. Watkins accepted Columbia's proposed Choice Administration Charge ("CAC"), which allocates an additional $0.242 million to full tariff LDS customers. This proposed rate design change must be considered in developing a proposal that limits any particular class percentage increase based on a multiple of the Company's overall increase. The revenue increase percentage to look at in this respect is Columbia's total requested non-gas revenue increase of $54.1 million, or 18.36% and is shown on Mr. Watkins' Table 6, page 25.[2] The 30.9% increase proposed by Mr. Watkins for full tariff LDS customers is 1.68 times the system average increase. This exceeds his

[2] As set forth in my Direct Testimony and OSBA's Direct Testimony, both Mr. Knecht and I determined that the percentage increase for the Company's total requested $54.1 revenue increase is 18.2%. I am utilizing Mr. Watkins' 18.36% percentage for purposes of my response in Rebuttal Testimony given that the differential is fairly small.

1.50 criterion that only includes base revenues and does not consider the effect of the CAC.

To conclude, I recommend that the Commission consider the effect of the proposed CAC on any class' total revenue increase percentage in this proceeding. The Company's cost allocation proposal for the CAC would have a significant impact on LDS customers. Of course, I opposed the Company's proposed CAC in my Direct Testimony and suggested an alternative charge that collects CAC costs on a per customer basis, rather than on a volumetric basis.

Q. On page 12 of his Direct Testimony, Mr. Knecht cited gradualism as one of the most important non-cost considerations in the revenue allocation process. Is his recommended increase of 36.3% to full tariff LDS customers consistent with gradualism?

A. A 36.3% increase is definitely not consistent with gradualism. According to Mr. Knecht, this is increase is two times the overall system average revenue increase. At the Company's requested increase of 18.2% shown in Table IEc-2, a 36.3% increase would, in my view, constitute rate shock to full tariff LDS customers. I recommend that the Commission reject Mr. Knecht's proposed increase to full tariff LDS customers.

Q. Did you note any problems with Mr. Knecht's revenue allocation proposal contained in Table IEc-3?

A. Yes. Mr. Knecht inappropriately reallocated adjustments from the LDS and MDS classes based on non-flex volumes for the LDS class. This resulted in LDS full tariff customers being allocated far too much of the revenue differential between flexed revenues and full cost of service.

Mr. Knecht noted on page 15 of his Direct Testimony that the cost shortfall for the LDS class is primarily demand-related. He further testified that he allocated this shortfall to all customer classes based on volumes. However, volumes are not a reasonable proxy for allocating demand related costs. This is because there is a significant difference between the LDS class' peak demand allocator and its volumetric allocator. Please refer to Rebuttal Table 1, which presents customer class design day demand and volumetric allocation factors from page 12 of the Company's CD CCOSS. This table also shows the allocation percentages used by Mr. Knecht for the LDS and MDS adjustments in Column (3). The final column in Rebuttal Table 1 also presents customer class current base revenue percentages excluding flex rate revenues. I developed these percentages from the base revenues shown on page 6 of the Company's CCOSS.

Rebuttal Table 1

Class Allocation Factor Comparison

	(1) Design Day %	(2) Annual Volumes %	(3) Knecht Non-Flex Vol. %	(4) Current Base Rev. %
RS/RDS	58.0%	45.3%	51.5%	72.7%
SGS/SGDS	24.9%	19.5%	22.2%	18.7%
LGS	1.1%	1.2%	1.4%	0.7%
SDS	6.6%	8.8%	10.0%	4.2%
LDS	9.4%	25.2%	14.9%	3.7%
Totals	100.0%	100.0%	100.0%	100.0%

Columns (1) and (2) show the large difference between the LDS class' design day demand and volumetric allocation factors in the CCOSS. Note that the volumetric allocator is much greater than the peak demand allocator. This is due to the fact that the LDS class uses natural gas more evenly throughout the year, including the non-heating season during which temperature sensitive loads are not present. Another way of saying this is that the LDS class has a higher load factor than the residential class, which consumes gas primarily during the winter heating season.

Comparing Column 1 to Column 3, note that Mr. Knecht's recommendation allocates 14.9% of the cost shortfall to the LDS full tariff customers. *This is a greater percentage than the peak demand allocator for the entire LDS class.* Since 47.6% of the LDS volumes are subject to flex contracts, the peak demand for the LDS full tariff customers would be much smaller than the 9.4% design day peak demand allocator for the entire class.

Rebuttal Table 1 shows that Mr. Knecht's volumetric allocator is inappropriate for allocating demand related costs to customer classes.

Q. How should revenue differences from flex customers be allocated to customer classes?

A. Since we do not have a separate peak demand allocator for the full tariff LDS customers, a reasonable proxy would be current base revenues less flex rate revenues. These percentages are shown in Column (4) of Rebuttal Table 1. The LDS full tariff customers' percentage of current base revenues is 3.7%.

Q. How does the reallocation of the revenue differential from flexing affect your Direct Testimony?

A. On pages 18 and 19 of my Direct Testimony, I recommend that if the Commission were to adopt the Company's Average study, the full tariff LDS customers should receive a 1.9% increase. However, this recommendation did not include a reallocation of the revenue differential from flex rate customers. The Company raised this point in discovery to CII. I have included my response to Columbia's first question of its Interrogatories and Requests for Production of Documents as Exhibit No. ____(RAB-5). In this response, I provided the approximate full cost of service shortfall from the LDS class after a 1.9% increase was applied to full tariff customers.

I then allocated that shortfall to the LDS full tariff customers using current base revenues less flex revenues. I then added this additional increase to the 1.9% increase I recommended in my Direct Testimony, resulting in a revised recommended increase to the LDS full tariff customers of $387,925, or 3.95%.

Q. Have you prepared an exhibit showing how this reallocation would affect all customer classes using the Company's Average CCOSS?

A. Yes. Please refer to Exhibit No. ___(RAB-6). This is a summary page is similar to my Exhibit No. ____(RAB-4) that was attached to my Direct Testimony. Exhibit No. ____(RAB-6) shows how the revenue differential from the LDS flex rate customers should be allocated to all customer classes using current base revenues less flexed revenues. Line 26 shows each class' increase after the reallocation of the LDS flex customers revenue differential from full cost of service revenues. Lines 27 and 28 also present the reallocation of the MDS revenue reduction to all other classes based on current base revenues less flexed revenues. Please note that the amount of LDS flexed revenue difference from cost of service shown on Line 25 differs slightly from the amount in my response to Columbia's discovery request. This is due to the effect of State Tax Adjustment Surcharge ("STATS") revenues in current revenues, but the difference is negligible.

Finally, lines 29 and 30 show each class' non-gas cost revenues and the percentage increase in gas cost revenues from line 28.

Q. Mr. Baudino, if the Commission chooses the Company's P&A CCOSS as the basis for class cost and revenue responsibility in this proceeding, should the increase to the full tariff LDS customers be mitigated?

A. Yes. As I did in Columbia's last rate case, I recommend that the increase be limited to 1.25 times the system average increase in non-gas cost revenues. This would include any effect of the Commission's decision with respect to the CAC. In other words, if the Commission approves the Company's proposed CAC, then the 1.25 cap should include the effect of this new charge on LDS full tariff customers.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket Nos. R-2014-2406274**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE COLUMBIA INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.

JULY 2014

COLUMBIA INDUSTRIAL INTERVENORS
RESPONSES TO INTERROGATORIES – SET I
OF COLUMBIA GAS OF PENNSYLVANIA, INC.

DOCKET NO. R-2014-2406274

CPA-I-1 Reference CII statement No. 1, pages 17-19 and Exhibit RAB-3, and the alternative recommendation that non-flex LDS customers receive a 1.9% revenue increase.

a. Would Mr. Baudino agree that the calculated total cost to serve LDS customers under the Average CCOSS, system average return, is $19,118,830?

b. What would be the approximate revenues recovered from the LDS class at the proposed rates assuming no increase is applied to flex rate customers and Mr. Baudino's proposal of a 1.9% revenue increase to non-flexed, full tariff LDS customers is adopted?

c. What is Mr. Baudino's proposal for recovery of the revenue differential between the total cost to serve LDS customers, calculated under subpart a, and the revenues recovered from the LDS class under subpart b?

RESPONSE:

a. Yes.

b. The approximate revenues recovered would be as follows:

Full tariff LDS revenues	9,832,457
CII recommended 1.9% increase	186,817
Full tariff LDS revenues with increase	10,019,274
Flex rate LDS customer revenues	3,620,999
Miscellaneous Revenues (approx.)	43,185
Total LDS revenues after 1.9% increase	13,683,458

Please see the attached spreadsheet for the calculations.

c. It would be appropriate to spread the revenue differential to all customer classes, except MDS, based on current base revenues less flex rate revenues. The revenue differential is $5,435,372. Each customer class' share of base revenues, less flex rate revenues and excluding MDS is attached to this response. In preparing this response, Mr. Baudino utilized the Company's Average CCOSS spreadsheet, Exhibit 111 Schedule 3, page 6. Please refer to the attached spreadsheet for the calculation. Full tariff LDS customers' share of base revenues is 3.7%. The LDS full tariff customers would thus be allocated $201,109 in addition to the 1.9% increase that Mr. Baudino recommended in his Direct Testimony. This would result in an increase to the LDS full tariff customers of $387,925, or 3.95%.

Response provided by:
Richard Baudino

COLUMBIA INDUSTRIAL INTERVENORS
CLASS REVENUES AT SYSTEM AVERAGE RATE OF RETURN
WITH REALLOCATION OF LDS AND MDS REVENUE ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2015

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE		542,204,578	393,625,727	110,694,623	7,165,057	12,225,787	16,623,195	1,870,190
2	PRODUCTS PURCHASED		189,783,736	134,780,295	49,734,133	4,896,000	-	-	373,308
3	OPERATING & MAINTENANCE EXPENSES		157,805,570	125,308,645	21,010,583	713,320	3,958,123	6,787,178	27,721
4	DEPRECIATION & AMORTIZATION		46,522,945	34,085,704	7,726,790	254,344	1,617,095	2,817,318	21,695
5	TAXES OTHER THAN INCOME		3,494,437	2,611,732	555,209	18,411	114,212	194,216	658
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		397,606,688	296,786,376	79,026,714	5,882,075	5,689,430	9,798,712	423,382
7	OPERATING INCOME BEFORE TAXES		144,597,890	96,839,351	31,667,908	1,282,983	6,536,357	6,824,483	1,446,808
8	INCOME TAXES		44,644,804	29,160,259	10,444,022	427,327	2,175,648	1,842,497	595,053
9	INVESTMENT TAX CREDIT	12	(360,240)	(259,751)	(60,967)	(2,118)	(13,466)	(23,801)	(137)
10	NET INCOME TAXES		44,284,564	28,900,508	10,383,055	425,208	2,162,182	1,818,696	594,916
11	OPERATING INCOME		100,313,325	67,938,843	21,284,853	857,774	4,374,175	5,005,787	851,892
12	RATE BASE		1,185,793,357	848,550,196	208,794,073	8,424,968	42,921,083	76,691,923	411,113
13	RATE OF RETURN EARNED ON RATE BASE		8.460%	8.006%	10.194%	10.181%	10.191%	6.527%	207.216%
14	UNITIZED RETURN		1.00	0.95	1.21	1.20	1.20	0.77	24.49
15	Operating Income at Uniform System ROR		100,313,325	71,783,917	17,663,135	712,718	3,630,950	6,487,827	34,778
16	Operating Income difference from Columbia Proposed Revenues		(0)	3,845,073	(3,621,719)	(145,056)	(743,225)	1,482,040	(817,114)
17	Revenue Conversion factor		1.68391906	1.68391906	1.68391906	1.68391906	1.68391906	1.68391906	1.68391906
18	Revenue Increase (Decrease) Required from Columbia Proposed Revenues		(0)	6,474,793	(6,098,681)	(244,262)	(1,251,531)	2,495,635	(1,375,953)
19	Total Revenues at System Average Rate of return		542,204,578	400,100,519	104,595,941	6,920,795	10,974,256	19,118,830	494,237
20	Total Revenues at Current Rates		488,096,822	353,370,762	100,899,940	6,899,584	11,566,128	13,502,737	1,857,672
21	Revenue Increase @ System Average Rate of Returh		54,107,756	46,729,758	3,696,002	21,211	(591,872)	5,616,093	(1,363,435)
22	1.90% Increase to LDS Full Taroff customers							186,817	
23	LDS Revenue Difference at System Average Rate of Return less 1.90% full tariff increase							5,429,277	
24	Customer class Base Revenue % Less Flex Revenues and MDS		100.0%	72.7%	18.7%	0.7%	4.2%	3.7%	
25	Allocation of LDS Revenue Differential			3,949,172	1,013,022	39,159	229,167	198,756	
26	Total Revenues at system average ROR including reallocation of LDS Flex Difference		54,107,756	50,678,930	4,709,024	60,370	(362,705)	385,573	(1,363,435)
	Reallocation of MDS reduction			(991,742)	(254,397)	(9,834)	(57,550)	(49,913)	
	Total Revenue Increase with reallocations of MDS reduction and LDS Flex Differential		54,107,756	49,687,188	4,454,627	50,536	(420,255)	335,660	
	Non-gas cost revenues		296,587,211	217,368,655	50,709,097	1,956,231	11,566,128	13,502,737	1,484,364
	Percentage Increase in Non-gas cost revenues		18.2%	22.9%	8.8%	2.6%	-3.6%	2.5%	0.0%

Exhibit No. __ (RAB-6)

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Via Overnight Mail

November 24, 2014

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission v. West Penn Power Company
Docket No. R-2014-2428742 and C-2014-2442667

Dear Secretary Chiavetta:

Please find enclose the original and one (1) copy of the DIRECT TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION for filing in the above-captioned proceeding.

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place this document of file.

Respectfully submitted,

David F. Boehm, Esq. (PA Attorney I.D. # 72752)
BOEHM, KURTZ & LOWRY

COUNSEL FOR AK STEEL CORPORATION

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cc: Certificate of Service
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P.O. Box 3265

CERTIFICATE OF SERVICE

I hereby certify that on this 24th day of November, 2014 I served a true and correct copy of the DIRECT TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION on the following persons in the matter specified in accordance with the requirements of 52 Pa. Code §1.54.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL CORPORATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

NOVEMBER 24, 2014

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

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Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

DIRECT TESTIMONY OF RICHARD A. BAUDINO ON BEHALF OF AK STEEL

I. INTRODUCTION

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 to 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 ____(RAB-1) summarizes my expert testimony experience.

Q. **Have you previously testified in proceedings before the Pennsylvania Public Utility Commission ("PPUC" or "Commission")?**

A. Yes. I have participated in thirty-seven proceedings before the Commission.

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

A. I am testifying on behalf of AK Steel Corporation, a large industrial customer taking service on Rate PP46.

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to address issues relating to class cost of service and the allocation of the overall approved revenue increase to rate classes. In addressing these issues, I will also respond to the Direct Testimony of West Penn Power Company ("WPP" or "Company") witness Hillary E. Stewart.

Q. Please summarize your conclusions and recommendations.

A. My conclusions are as follows:

1. In its present state, the class cost of service study ("CCOSS") presented by Ms. Stewart cannot be relied upon to allocate costs and revenue responsibility to WPP's customer classes. My review of WPP's class cost of service study revealed five calculation errors. The Company acknowledged the existence of these errors in responses to discovery, which I shall present later in my testimony.
2. In addition to the calculation errors in the Company's CCOSS, I also identified a conceptual allocation error that should be corrected. WPP's CCOSS inappropriately classifies and allocates costs in Account 362 - Station Equipment, also known as substations. WPP's allocation method causes an excessive allocation of substation costs to rate classes that only

take service at 23 kilovolts ("kV") and above.

3. In my testimony, I will present two revised CCOSSs to the Commission. The first CCOSS corrects the five calculation errors admitted to by the Company in its responses to discovery and reveals a major shift in customer class cost responsibility. I developed this corrected WPP CCOSS so the Commission can clearly discern the effect of correcting the Company's five admitted errors in its filed CCOSS.

4. As a result of the application of this first revised CCOSS, Rate PP46 customers move from a -0.77% return on rate base in Ms. Stewart's filed CCOSS to a 4.65% return in the corrected WPP CCOSS. This corrected rate of return for Rate PP46 customers is nearly equal to WPP's current rate of return of 4.78%.

5. The second CCOSS I prepared, which I refer to as the AK Steel CCOSS, includes the correction to the Company's allocation of Account 362 - Station Equipment costs as well as the corrections to the five CCOSS errors to which WPP has admitted. The AK Steel CCOSS shows that the current rate of return for Rate PP46 customers is 18.43%, compared to WPP's overall current rate of return of 4.83%.

6. Correcting all of the errors in Ms. Stewart's filed CCOSS shows that Rate PP46 customers should receive a revenue decrease of $-0.884 million in this proceeding. Ms. Stewart's proposed revenue increase to Rate PP46 of $1.921 million is totally unjustified and should be rejected by the Commission.

7. I recommend that the Commission adopt my recommended AK Steel CCOSS, which corrects the erroneous calculations in WPP's CCOSS and

properly allocates the costs of substations to customers taking service at 23 kV and above.

8. With respect to revenue allocation, I recommend that the Commission reduce revenue subsidies at current rates by 50% as shown in the AK Steel CCOSS. In addition, no customer class should receive a rate decrease, although my recommended AK CCOSS shows that Rate 46 customers should receive a significant rate decrease. Instead, I recommend that Rate PP46 customers receive no increase in this case.

II. CLASS COST OF SERVICE

Q. Have you reviewed the Company's filed distribution class cost of service study in this case?

A. Yes.

Q. Please briefly summarize the important aspects of a class cost of service study.

A. A class cost of service study allocates and assigns the total joint cost of providing utility service to the classes of customers receiving that service. In certain instances, the subject utility can identify and directly assign costs to customers. But for the vast majority of costs, a cost of service study is required so that the remaining costs may be allocated to customers.

The development of a class cost of service study consists of three steps: functionalization, classification, and allocation. Step 1, functionalization, involves separating the utility's investment and expenses into major functional categories. For integrated electric utilities, these categories include production, transmission, and distribution. The FERC Uniform System of Accounts provides the method by which costs are identified and segregated into these various functional categories.

Step 2 is classification. Once functionalization is complete, the utility's costs are classified into demand, energy, and customer components. Demand-related costs are fixed in the short run and are sized based on the yearly demands of the utility's customers. Fixed production and transmission costs and a significant portion of the distribution system investment in poles, wires, etc. is considered demand-related. Energy-related costs vary with kWh consumption and include fuel and variable purchased power costs. Customer-related costs are associated with the number of customers and include items such as meters and services. It is also appropriate to classify a portion of distribution investment in FERC Accounts 364 through 370 as customer-related.

Step 3 is allocation. After costs are classified, they are allocated to customer classes based on each class' contribution to the respective cost classifications. Generally speaking, demand costs are allocated based on class contributions to system peak and/or non-coincident peaks. Energy costs are allocated based on class kWh consumption. Customer costs are allocated based on the number of customers or on weighted customer allocation factors.

Q. Why is a properly constructed CCOSS important in the ratemaking process?

A. A properly performed class cost of service study assigns and allocates the utility's total cost of service to the customer classes that cause the utility to incur the cost, and that receive that service. Based on current class revenues, the regulatory commission may then determine whether each customer class is paying its fair share of costs and can then allocate any revenue increase (or decrease) accordingly. For example, a customer class that is not paying its fair share of costs should receive a percentage revenue increase greater than the overall system increase. Likewise, a customer class that is paying more than its fair share of costs should receive a lower than average percentage increase. In certain cases, it may be appropriate for such a class of customers to receive no increase or even a decrease in rates if that class is paying rates greatly in excess of its allocated cost of service.

Accurate cost allocation also promotes economic efficiency. If electricity prices are based on an accurate assessment of the underlying cost to serve customers, then customers can make correctly informed decisions about their usage of electricity. For example, many industrial firms use significant amounts of electricity in their production processes. If the price these companies pay for electricity is based on costs, then they will be able to produce their goods and services at the lowest and most efficient cost for society. If electricity prices are set above the actual underlying cost, then these goods and services will be overpriced, under produced, or both.

Q. Generally describe the approach used by Ms. Stewart with respect to cost allocation.

A. WPP witness Stewart began a discussion of the Company's CCOSS methodology on page 6 of her Direct Testimony. Non-coincident peak ("NCP") demands were used to allocate costs that are classified as demand-related. WPP's method allocates demand-related costs for large distribution plant accounts based on NCP demands of three groups of customers. The first group, designated as "PRI" in the Company's CCOSS, consists of customers that receive service at primary voltage and use only the Primary Distribution system. The second group, "SEC", are customers that take service at secondary voltage and that use both the Primary and Secondary distribution system. The third group, "PRI_SEC", are all customers using the distribution system and consists of Primary and Secondary customers. Ms. Stewart's Appendix B provides a diagram showing the differentiation between WPP's Primary and Secondary distribution system. The Company's CCOSS further functionalizes plant Accounts 361 - 368 between Primary and Secondary voltage levels and is shown on pages 10 and 11 of Ms. Stewart's Direct Testimony.

WPP's CCOSS then classified its system cost of service into demand and customer classifications. Ms. Stewart explained beginning on page 12 that plant Accounts 364 - 369 were classified based on a minimum grid study, which was provided in Supporting Study No. 7. This study determined the minimum size of poles, conductors, transformers, and service drops required to serve a customer. The cost of this "minimum size system" determined the customer component of the above accounts and the remainder is classified as the demand component. NCP is then used to allocate the demand-related portion of these accounts and the customer component is allocated based on the number of customer accounts. The rest of WPP's distribution system is allocated to customer classes according to their respective demand and customer allocators as explained by Ms. Stewart on pages 12 and 13 of her Direct Testimony.

Q. Please summarize the results of WPP's CCOSS as filed by Ms. Stewart.

A. Table 1 below shows class rates of return and unitized rates of return from WPP's filed CCOSS. Unitized rate of return is a measure of how close a customer class rate of return is to the system average rate of return. For example, suppose that a utility company's overall rate of return on rate base is 10%. Then suppose that Customer Class A has a return on rate base of 11%. The unitized rate of return for Customer

Class A, then, is 1.10 (11% divided by 10%), which means that Customer Class A's rate of return is 10 percent higher than system average.

Table 1
CCOSS Results - As Filed by WPP

	WPP as Filed		Revenue Increases (000s)	
	Present ROR	Unitized ROR	to Full Cost of Service	WPP Proposed
RS	3.67%	0.77	$71,742	$60,825
GS10	12.15%	2.54	(98)	$137
GSS	-3.99%	(0.84)	$17,654	$4,544
GSM	15.37%	3.22	(19,492)	$3,512
PP40	-1.38%	(0.29)	$9,337	$6,147
GSL	11.39%	2.38	(3,720)	$734
POL	20.23%	4.24	(1,760)	$2,131
PSU	6.51%	1.36	$127	$401
PP44	-4.15%	(0.87)	$221	$99
PP46	-0.77%	(0.16)	$3,216	$1,921
AGS	21.70%	4.54	(6)	$23
STLT	4.96%	1.04	$1,403	(1,852)
Total	4.78%	1.00	$78,623	$78,623

WPP's filed CCOSS shows that Rate PP46 is actually earning a negative rate of return of -0.77%. The Company's CCOSS suggests that current rates for Rate PP46 are not even covering basic expenses to serve this class, much less providing a return on rate base. However, as I will discuss next, the Company's study erroneously included plant additions in the future test period as substation costs, when in reality such new investment was actually associated with poles and fixtures. The effect of this error, which the Company admits, has a significant and material impact on the Company's cost of service results. This error was identified by the Company in a response to Staff data request I&E-RB-14-D and confirmed in a response to an AK Steel data request, Set III No. 1.

Q. During your review, did you discover other errors in the Company's CCOSS?

A. Yes, I discovered a total of five errors during a detailed review of the Company's CCOSS, an active version of which was provided in response to discovery.

Q. Did you prepare a CCOSS that corrected these errors?

A. Yes. Using the active WPP CCOSS spreadsheet I corrected the errors I found that were admitted to by WPP in responses to discovery. As I will show later in my testimony, correcting these admitted errors results in a significant change for Rate PP46 customers.

<u>Corrections to Admitted Errors in WPP's CCOSS</u>

Q. Please discuss the first error in WPP's CCOSS.

A. The original cost balance for Account 362 - Station Equipment is overstated and the balance for Account 364 - Poles and Fixtures is understated. This error also impacts depreciation expense, which is calculated on the plant balances.

In response to I&E-WP-RB-14-D, the Company noted that an adjustment for budgeted additions and retirements on Exhibit RAD 47 was incorrectly shown in Account 362 - Station Equipment when it was actually related to Account 364 - Poles and Fixtures. Please refer to Exhibit No. ___(RAB-2) for a copy of this data request and the response from WPP. A review of Exhibit RAD 46 shows the same misalignment. I verified this because the retirements are shown in Account 364 -

Poles and Fixtures in the calculation of depreciation reserve. RAD 46 is incorporated into the CCOSS model, and is the source of the plant balances for the CCOSS. Please refer to Exhibit No. ___(RAB-3) for WPP's response to AK Steel Set III, Nos. 1 and 2 and the Company's response, which verified the existence of this error and provided a corrected RAD-46.

Finally, I note that WPP did not indicate that these corrections would change its requested revenue requirement, though the changes should affect total depreciation expense. I therefore shifted depreciation expense among accounts, but kept total depreciation the same. However, there is a change in the plant balance for Account 370.4, which reduces rate base and therefore produces a slightly higher rate of return at present and proposed rates.

Q. What steps did you take to correct this error in the Company's CCOSS?

A. I made the following corrections to WPP's CCOSS:

- 'RAD 46 Attach B p 1 2': Corrected the beginning balances and Additions/Retirements for Accounts 359.1, 362, 364, 368, 369, 370.4 to match the response to AK Steel Set III No. 2.
- 'RAD 53 Attach A': Changed the depreciable base for Account 362 to refer to the corrected balance, which corrected the calculated depreciation expense. Then changed the depreciation expense for Account 364 so there was no net change in total depreciation expense for the two accounts.
- 'RAD 53 Attach A': made the same adjustment as above for Accounts 368 and 369.

Q. Please describe the second error you identified in WPP's filed CCOSS.

A. The second error in the Company's CCOSS stems from a misalignment of the allocation factor used to allocate the demand components of Maintenance Expense - Overhead Conductors, Depreciation Expense - Overhead Conductors, and Accumulated Depreciation - Overhead Conductors. All three of these accounts are allocated using an internally generated allocation factor entitled 'DMND_RB_PLT_D_OC_365', which should be the total allocated amount for Account 365. However, there is an error in the Company's formula that causes the allocator to reflect only the Primary component of Account 365, rather than the total amount in Account 365.

In order to correct this erroneous formula, I modified the formula in Row 219 in the "Demand Dollars" worksheet of WPP's CCOSS. The formula should sum the rows 98 - 99, rather than rows 97 - 98.

Q. Please discuss the third error you found in the Company's CCOSS.

A. I discovered that the Customer component allocator based on Account 364 is incorrect. This is due to an error in the formula that drives the allocator 'CUST_RB_PLT_D_OC_364'. In order to correct this erroneous formula, I modified the formula in Row 218 in the "Customer Dollars" worksheet of WPP's CCOSS. The formula should sum the rows 98 - 99, rather than rows 97 - 98.

Q. Did WPP acknowledge these two errors during the discovery process?

A. Yes. The Company acknowledged these errors in its response to OSBA Set II, No. 3. Please refer to Exhibit No. ___(RAB-4) for a copy of this response.

Q. Please discuss the fourth error you discovered.

A. The Non-coincident peak ("NCP") allocators for the GSS class are incorrect. This was due to incorrect cell references in the Company's CCOSS. WPP confirmed this error in its response to OSBA Set II, No.2, which I have attached as Exhibit No. ___(RAB-5). I made the indicated correction in the 'Demand Allocators' worksheet of the Company's CCOSS.

Q. Please discuss the fifth error you found in the Company's CCOSS.

A. The Primary customer allocation factor is incorrect because it omits Subtransmission customers, which the Company includes in its Primary allocation factors. This omission was admitted to by WPP in its response to OSBA Set II, No. 4.a., which is attached as Exhibit No. ___(RAB-6). I included this correction in the 'Future Allocation Factor' and 'Allocator Inputs' worksheets of WPP's CCOSS.

Q. Did you prepare a CCOSS that corrects the five errors admitted to by the Company?

A. Yes. Please refer to Exhibit No. ___(RAB-7) for a summary of the results of WPP's corrected CCOSS at present rates. It is important to note that this study is WPP's filed CCOSS with corrections to errors that have been admitted by the Company. Table 2 below presents the corrected class rates of return, relative rates of return, and dollar subsidies for each customer class at present rates.

Table 2
CCOSS Results - Corrected (Admitted Errors)

	Corrected		Subsidy	Revenue Increases (000s)	
	Present ROR	Unitized ROR	at Present Rates (000s)	to Full Cost of Service	WPP Proposed
RS	3.19%	0.66	$28,021	$86,224	$60,825
GS10	13.38%	2.77	(186)	(112)	$137
GSS	-3.62%	(0.75)	$13,700	$19,234	$4,544
GSM	19.50%	4.03	(31,211)	(23,946)	$3,512
PP40	2.81%	0.58	$1,031	$2,769	$6,147
GSL	16.72%	3.46	(9,322)	(6,644)	$734
POL	18.14%	3.75	(2,132)	(1,585)	$2,131
PSU	19.23%	3.98	(560)	(428)	$401
PP44	-7.41%	(1.53)	$101	$129	$99
PP46	4.65%	0.96	$33	$650	$1,921
AGS	28.46%	5.89	(10)	(8)	$23
STLT	3.82%	0.79	$536	$2,338	(1,852)
Total	4.83%	1.00	(0)	$78,623	$78,623

Q. How do the CCOSS results shown in Table 2 compare to the Company's uncorrected CCOSS results you summarized in Table 1?

A. The most striking difference from correcting the admitted errors in the Company's CCOSS is the effect on Rate PP46. Rate PP46 goes from a -0.77% rate of return on rate base in WPP's filed CCOSS to 4.65% with the corrections I described earlier. Regarding customer class revenue subsidies, Rate PP46 drops from receiving a subsidy of $2.003 million at present rates to a subsidy of only $33,000 in the corrected CCOSS. Rate PP46's corrected rate of return is nearly equal to WPP's system average increase.

Q. What is your conclusion with respect to the corrected WPP CCOSS you presented in Exhibit No. ___(RAB-7)?

A. It is abundantly clear that without making the corrections to the admitted errors in WPP's CCOSS, there would be a devastating and completely unreasonable rate impact on Rate PP46 customers. The Commission should reject the Company's proposed rate increase of $1.921 million for Rate PP46 customers, which was based on an erroneous cost of service study.

Q. Is there any other known error in the Company's CCOSS?

A. Yes, in response to OSBA Set II, No. 4.e., the Company stated that there was an error in the determination of the assignment of cost to Primary service customers in their Primary/Secondary study. The response did not provide sufficient information for me to evaluate or include this adjustment at this time. If the adjustment is correct and appropriate, it would shift some costs from Secondary classes to Primary classes.

Q. Does this conclude your discussion and analysis with respect to known errors in the Company's CCOSS?

A. Yes. I will now discuss a methodological flaw in the Company's CCOSS with respect to the allocation of substations.

Correction to WPP Account 362 - Station Equipment

Q. Please describe how WPP's CCOSS allocates the cost of substations.

A. Account 362 - Station Equipment (also known as substations) is allocated on the basis of customer class NCP regardless of the voltage level at which WPP's customers take service. In other words, the Company's allocation of distribution substations assumes that all substations serve all distribution loads whether customers take service at primary or secondary voltage levels.

Q. Is the Company's allocation of substations correct?

A. No. WPP's CCOSS ignores the fact that some substations only serve loads that take service below 23 kV. Other substations serve only Primary voltages greater than 23 kV and may be used by both Primary customers above and below 23 kV and by Secondary customers. Because of this improper functionalization of substations, customers taking service at voltages greater than 23 kV are paying for substation costs for which they are not responsible.

The Company's CCOSS properly analyzes the uses of Primary lines and related facilities to separate those serving Primary customers and those dedicated to serving only Secondary customers. This is very important from the standpoint of cost allocation because the lines used to serve customers who take service at Secondary voltage levels do not serve customers who take service at Primary voltage levels. If the costs associated with Secondary voltage facilities were allocated to Primary voltage customers, then Primary customers would be assigned costs for which they are not responsible and would be subsidizing Secondary customers in the process. Unfortunately, this is the result with respect to the way WPP allocated the cost of substations in its CCOSS.

Q. How should substations be functionalized and allocated in the Company's CCOSS?

A. Since some rate schedules serving large primary customers are restricted to serving customers at 23 kV and above, this is a logical dividing point to prevent higher voltage customers from being allocated the cost of facilities that are dedicated to serving lower voltage customers. I performed a study using WPP's FERC Form 1 data to calculate the percentage of substation capacity that has a secondary voltage of less than 23 kV. This calculation is shown in Exhibit No. ___(RAB-8).

Q. How did you incorporate the separation of substations serving loads at 23 kV and above and those only serving loads at voltages less than 23 kV?

A. I created a weighted NCP Allocator (DMD_NCP_SUB) that properly reflects the division of substations at 23 kV. Weights from the FERC Form 1 analysis presented in Exhibit No. ___(RAB-8) are in Row 1 of Columns AN and AP in the 'Allocator Inputs' worksheet in my corrected WPP CCOSS. Columns AO and AQ of that worksheet represent an allocation of the portion of the cost of Account 362 - Station Equipment associated with greater than 23 kV and less than 23 kV service, respectively. Using this split for substation costs properly classifies and allocates these costs to customer classes taking service at Primary and Secondary voltage levels.

Q. Have you prepared a CCOSS that correctly functionalizes and allocates substations?

A. Yes. Please refer to Exhibit No. ___(RAB-9), which presents a summary of my AK Steel recommended CCOSS at present rates. This CCOSS incorporates all of the corrections in the Corrected WPP CCOSS presented in Exhibit No. ___(RAB-7) and my recommended functionalization and reallocation of substation costs. Table 3 below presents customer class rates of return, unitized rates of return, and dollar subsidies.

Table 3
AK Steel CCOSS Results - Corrected Substation Allocation

	Present ROR	Unitized ROR	Subsidy at Present Rates (000s)	Revenue Increases (000s) to Full Cost of Service	Revenue Increases (000s) WPP Proposed
RS	3.07%	0.63	$30,418	$89,254	$60,825
GS10	12.77%	2.64	(178)	(101)	$137
GSS	-3.64%	(0.75)	$13,789	$19,347	$4,544
GSM	18.42%	3.81	(30,087)	(22,524)	$3,512
PP40	12.28%	2.54	(2,029)	(1,099)	$6,147
GSL	15.35%	3.18	(8,730)	(5,895)	$734
POL	17.98%	3.72	(2,119)	(1,568)	$2,131
PSU	15.53%	3.21	(482)	(328)	$401
PP44	-6.74%	(1.39)	$48	$62	$99
PP46	18.43%	3.81	(1,180)	(884)	$1,921
AGS	27.89%	5.77	(10)	(8)	$23
STLT	3.78%	0.78	$558	$2,366	(1,852)
Total	4.83%	1.00	$0	$78,623	$78,623

Q. How do the results of AK Steel CCOSS compare to the corrected WPP CCOSS you presented in your Exhibit No. ___(RAB-7)?

A. My recommended AK Steel CCOSS shows that with the proper allocation of substations included in the analysis, Rate PP46 is paying significantly more than its fair share of cost to serve at present rates. These customers are paying a subsidy to other rate classes of $1.180 million per year at present rates. Rates RS and GSS are the main recipients of subsidies from the other rate classes, mainly due to the fact that these rate classes are not paying their fair share of substation costs.

Q. Should the Commission use your recommended AK Steel CCOSS for purposes of revenue allocation in this proceeding?

A. Yes. The AK Steel CCOSS corrects several major errors that the Company acknowledged in its responses to discovery and properly allocates the cost of substations in Account 362 - Station Equipment. In Section III of my testimony, I will present my recommended class revenue allocation based on the AK Steel CCOSS.

III. REVENUE ALLOCATION

Q. Based on your analysis and corrections of WPP's CCOSS in Section II, please present the results of the Company's revenue allocation proposal using the corrected WPP study.

A. Table 4 below presents the Company's revenue allocation proposal at its requested total system revenue increase using the corrected WPP CCOSS I summarized in Exhibit No. ___(RAB-7).

Table 4
WPP Proposed Increases - Results with Corrected CCOSS

	WPP Proposed Increases (000s)	Proposed ROR	Unitized ROR	Subsidy at Present Rates (000s)	Subsidy at Proposed Rates (000s)
RS	$60,825	6.76%	0.82	$28,021	$25,399
GS10	$137	19.66%	2.38	(186)	(249)
GSS	$4,544	-0.81%	(0.10)	$13,700	$14,690
GSM	$3,512	21.16%	2.56	(31,211)	(27,458)
PP40	$6,147	14.89%	1.80	$1,031	(3,379)
GSL	$734	17.66%	2.14	(9,322)	(7,378)
POL	$2,131	31.44%	3.81	(2,132)	(3,716)
PSU	$401	29.54%	3.58	(560)	(829)
PP44	$99	4.58%	0.56	$101	$30
PP46	$1,921	15.28%	1.85	$33	(1,271)
AGS	$23	86.05%	10.43	(10)	(32)
STLT	(1,852)	0.31%	0.04	$536	$4,190
Total	$78,623	8.25%	1.00	(0)	$0

As I stated earlier, Table 4 points out the significant shift of cost responsibility from PP46 customers when the Company's CCOSS is corrected. WPP's proposed revenue increase to Rate PP46 customers would result in a unitized rate of return of 1.85 and cause these customers to support a rate subsidy payment of $1.271 million per year to other rate classes. There is simply no justification to support the Company's proposed increase for Rate PP46 customers. Clearly, just the calculation corrections to the Company's cost study support an alternative revenue allocation. The Company based its proposed revenue allocation on the results of its class cost of service study that the Company now admits is erroneous. Putting aside my recommended substation cost allocation changes and just focusing on a corrected version of the Company's own study supports an entirely different allocation of any Commission approved revenue increase to each rate class.

Q. How do you recommend that the Commission allocate WPP's revenue increase in this proceeding?

A. For purposes of this proceeding, I recommend that the Commission move to reduce subsidies at current rates by 50%, based on my recommended AK Steel CCOSS. This approach accomplishes two very important goals with respect to revenue allocation. First, it accomplishes the goal of gradualism by limiting the class revenue increases that would otherwise occur if all subsidies were eliminated at once. Second, it moves customer classes toward paying their full cost to serve over a reasonable period of time, from one rate case to the next.

Q. Please show how your proposed 50% subsidy reduction method would work using your recommended AK Steel CCOSS.

A. Table 5 below shows the customer class increases that would result from reducing subsidies at current rate by 50% using the AK Steel CCOSS. This analysis and the recommended increases to each rate class are based on the Company's cost of service study, corrected to fix the errors that I discussed previously that have been acknowledged by the Company and correcting WPP's allocation of Account 362 - Station Equipment.

Table 5
Increases with 50% Subsidy Reduction
AK Steel CCOSS - No Class Decreases (000s)

	Proposed Increases	Pct. Increases
RS	$72,436	35.5%
GS10	-	0.0%
GSS	$4,301	37.5%
GSM	-	0.0%
PP40	-	0.0%
GSL	-	0.0%
POL	-	0.0%
PSU	-	0.0%
PP44	$34	121.5%
PP46	-	0.0%
AGS	-	0.0%
STLT	$1,852	30.7%
Total	$78,623	25.0%

Please refer to Exhibit No. ___(RAB-10) for a detailed summary of the calculations.

Q. **Do the results in Table 5 recognize a reasonable level of mitigation and gradualism?**

A. Yes. This is how I developed my recommended class revenue increases.

First, I eliminated any rate decrease that would otherwise occur for any rate class pursuant to a 50% subsidy reduction revenue allocation. The additional dollars from this adjustment were then used to mitigate the increases to any rate class receiving an increase on a proportionate basis.

Second, I further limited the revenue increase to the GSS class to 1.5 times the overall system average increase. I did this because the increase to GSS after the first step was unacceptably high. Therefore, additional rate mitigation for GSS customers was called for. Limiting the GSS class' increase to 1.5 times the system average increase moves these customers towards paying their fair share of costs without a burdensome rate increase. The revenue increase that GSS customers would have received without the 1.5 times system increase limit was shifted to the RS class, which after this shift was still below the 1.5 times system average limit.

I note that because I am only recommending a 50% subsidy reduction in this case, those rate classes currently receiving subsidies, namely RS and GSS, will continue to receive subsidies at proposed rates. This was necessary in order to accomplish a more gradual rate increase to these classes.

Finally, to the extent that the Commission does not approve the Company's full requested revenues increase, any Commission adjustments will first be used to reduce the increases for classes that are receiving increases. Based on my recommended AK Steel CCOSS, any such Commission adjustments would be assigned primarily to the residential, small general service and lighting classes. This would provide additional mitigation for these small customers.

Q. Why didn't you mitigate the increase for Rate PP44 customers?

A. Rate PP44 consists of very large customers for whom WPP's distribution charges are a very small portion of their overall bills. Although the percentage revenue increase for Rate PP44 is large, the effect on customers in this rate class will be very small. Indeed, the total revenue increase for Rate PP44 is only $34,000.

Q. Please show how this proposal would work using the corrected WPP CCOSS.

A. Please refer to Exhibit No. ___(RAB-11) for a detailed summary of the 50% reduction in class subsidies using the corrected WPP CCOSS. As in my analysis using the AK Steel CCOSS (Table 5), I modified the subsidy reductions such than no class would receive a revenue decrease. Any such decreases that would be justified by the 50% reduction to current subsidies were spread to classes that would have received the highest increases in order to mitigate the rate impact on these classes. Finally, I further limited the GSS revenue increase to 1.5 times system average, with the revenue difference assigned to Rate RS.

In addition, as I noted above, any Commission authorized adjustments to the Company's overall revenue increase amount will be credited only to rate classes receiving increases. Table 6 summarizes these increases.

Table 6
Increases with 50% Subsidy Reduction
WPP Corrected CCOSS - No Class Decreases

	Proposed Increases	Pct. Increases
RS	$69,904	34.3%
GS10	-	0.0%
GSS	$4,301	37.5%
GSM	-	0.0%
PP40	$1,977	28.9%
GSL	-	0.0%
POL	-	0.0%
PSU	-	0.0%
PP44	$69	247.7%
PP46	$556	23.2%
AGS	-	0.0%
STLT	$1,816	30.1%
Total	$78,623	25.0%

Q. Why did you present the revenue allocation in Table 6?

A. Although Table 6 is not based on my recommended AK Steel CCOSS, I present these numbers to the Commission in the event it chooses not to adopt my revenue allocation recommendations in Table 5. At the very least, the Commission should base its revenue allocation on the Company's CCOSS corrected for its five calculation errors I discussed previously.

Q. How would your revenue allocation work if the Commission reduces WPP's requested revenue increase in this case?

A. I recommend a uniform percentage scale-back of the increases shown in my Tables 5 and 6 in the likely event that the Commission adopts a lower revenue increase than WPP requested.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

AFFIDAVIT OF RICHARD A. BAUDINO

STATE OF NORTH CAROLINA)
COUNTY OF Stokes)

Richard A. Baudino being first duly sworn, deposes and states that:

1. He is a consultant with J. Kennedy & Associates, Inc.;

2. He is the witness who sponsored the testimony entitled "Direct Testimony and Exhibits of Richard A. Baudino" on behalf of AK Steel Corporation.

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and exhibits are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino
Richard A. Baudino

Subscribed and sworn to or affirmed before me this 21 day of November, 2014 by Richard A. Baudino.

Ruth G. Robertson
Notary Public

RUTH G. ROBERTSON
NOTARY PUBLIC
Stokes County, North Carolina
My Commission Expires 10-16-2017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. West Penn Power Company	Docket Number R-2014-2428742
Pennsylvania Public Utility Commission v. Pennsylvania Electric Company	Docket Number R-2014-2428743
Pennsylvania Public Utility Commission v. Pennsylvania Power Company	Docket Number R-2014-2428744
Pennsylvania Public Utility Commission v. Metropolitan Edison Company	Docket Number R-2014-2428745

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

NOVEMBER 24, 2014

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: Kennedy and Associates: **Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: New Mexico Public Service Commission Staff: **Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

**Expert Testimony Appearances
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Richard A. Baudino
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

**Expert Testimony Appearances
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Richard A. Baudino
As of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation

Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing
Response to I&E Interrogatory RB-14-D
Witness: R. A. D'Angelo

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSYLVANIA POWER COMPANY
WEST PENN POWER COMPANY
DOCKET NOS. R-2014-2428745, R-2014-2428743, R-2014-2428744 and R-2014-2428742

Bureau of Investigation and Enforcement WP RB-14-D:

"In reference to the $107,680,697 of additions and $10,768,070 of retirements for Account 362 – Station Equipment shown on West Penn Exhibit RAD-47, Attachment B, page 1, provide the following information for each project that supports the $107,680,697 of additions and $10,768,070 of retirements:

A. A description of each project;

B. Original cost;

C. Amount expended and retired to date;

D. Actual or expected in-service date;

E. Expected final cost and final retirement."

RESPONSE:

Please note: The additions /retirements were not shown on the correct line on the original West Penn Exhibit RAD-47, however, total plant numbers are unchanged. The additions / retirements were shown in Account 362 – Station Equipment but belong in Account 364 – Poles and Fixtures. The responses below relate to Account 364 – Poles and Fixtures.

A, B and E. See West Penn I&E RB-14-D, Attachment A.

C. See West Penn I&E RB-23-D, Attachment A, column Apr thru Jul Net Additions for Account 364.

D. This amount is comprised of multiple projects with various in-service dates.

Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing
Response to AK Steel Interrogatory Set III, AK-Q.3-1
Witness: R. A. D'Angelo

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSYLVANIA POWER COMPANY
WEST PENN POWER COMPANY
DOCKET NOS. R-2014-2428745, R-2014-2428743, R-2014-2428744 and R-2014-2428742

AK Steel Corporation WP Set III, AK-Q.3-1

"With regard to the Company's response to I&E WP RB-14-D, please confirm that the corresponding additions/retirements on West Penn Exhibit RAD-46, Attachment B, also are shown on the wrong line."

RESPONSE:

The additions/retirements on West Penn Exhibit RAD-46, Attachment B regarding account 362 were also shown on the wrong line.

Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing
Response to AK Steel Interrogatory Set III, AK-Q.3-2
Witness: R. A. D'Angelo

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSYLVANIA POWER COMPANY
WEST PENN POWER COMPANY
DOCKET NOS. R-2014-2428745, R-2014-2428743, R-2014-2428744 and R-2014-2428742

AK Steel Corporation WP Set III, AK-Q.3-2

"Please provide a corrected version of West Penn Exhibit RAD-46, Attachment B, showing the corrected Balance at 4/30/15 and the Adjusted Balance at 4/30/16 for each account.3"

RESPONSE:

See West Penn AK Steel Set III, No. AK-Q.3-2, Attachment A.

West Penn Power Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Plant-In-Service

Acct No	Description	Balance 4/30/15	Budget Activity: Additions	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 156,797	$ -	$ -	$ -	$ 156,797	$ -	$ 156,797
302	Franchise And Consents	-	-	-	-	-	-	-
	Total Intangible Plant	$ 156,797	$ -	$ -	$ -	$ 156,797	$ -	$ 156,797
	Land							
350.11	Transmission Substations	$ 1,860,781	$ -	$ -	$ -	$ 1,860,781	$ (1,860,781)	$ -
350.21	Transmission Lines	-	-	-	-	-	-	-
360.11	Distribution Substations.	6,334,162	-	-	-	6,334,162	-	6,334,162
360.21	Distribution Lines	-	-	-	-	-	-	-
389.1	General	2,130,320	-	-	-	2,130,320	(301,653)	1,828,667
	Total Land	$ 10,325,262	$ -	$ -	$ -	$ 10,325,262	$ (2,162,434)	$ 8,162,829
	TOTAL NON-DEPRECIABLE PLANT	$ 10,482,060	$ -	$ -	$ -	$ 10,482,060	$ (2,162,434)	$ 8,319,626
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 21,339,459	$ 351,270	$ -	$ -	$ 21,690,729	$ (3,071,407)	$ 18,619,322
303	Smart Meter Software 10 yr	26,332,200	-	-	-	26,332,200	-	26,332,200
303	Smart Meter Software 7 yr	2,831,862	13,696,258	-	-	16,528,120	-	16,528,120
	TOTAL INTANGIBLE PLANT	$ 50,503,521	$ 14,047,527	$ -	$ -	$ 64,551,049	$ (3,071,407)	$ 61,479,642
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL NUCLEAR PRODUCTION	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 30,908,872	$ -	$ -	$ -	$ 30,908,872	$ (30,908,872)	$ -
350.22	Easements - Trans. Lines	285,131	-	-	-	285,131	(285,131)	-
352.1	Structures, Improvements	6,635,866	-	-	-	6,635,866	(6,635,866)	-
353	Station Equipment	122,646,424	-	-	-	122,646,424	(122,646,424)	-
354	Towers And Fixtures	59,714,889	19,902,372	(1,990,237)	-	77,627,024	(77,627,024)	-
355	Poles And Fixtures	66,957,260	-	-	-	66,957,260	(66,957,260)	-
356.1	Overhd Conductr, Devices	72,833,035	-	-	-	72,833,035	(72,833,035)	-
356.2	Clearing, Grading of Land	34,377,437	-	-	-	34,377,437	(34,377,437)	-
358	Undergrnd Conductr,Devices	271,628	-	-	-	271,628	(271,628)	-
359	Roads And Trails	-	-	-	-	-	-	-
359.1	ARC Transmission	1,721	-	-	-	1,721	(1,721)	-
	TOTAL TRANSMISSION PLANT	$ 394,632,261	$ 19,902,372	$ (1,990,237)	$ -	$ 412,544,396	$ (412,544,396)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 10,258,899	$ -	$ -	$ -	$ 10,258,899	$ -	$ 10,258,899
360.22	Easements - Dist. Lines	429,151	-	-	-	429,151	-	429,151
361.1	Structures, Improvements	20,587,086	-	-	-	20,587,086	-	20,587,086
362	Station Equipment	298,241,372			-	298,241,372	-	298,241,372
364	Poles, Towers And Fixtures	442,281,336	94,927,364	(9,492,736)	-	527,715,964	-	527,715,964
365	Overhd Conductr, Devices	288,280,691	-	-	-	288,280,691	-	288,280,691
365.1	Clearing, Grading of Land	132,088,173	-	-	-	132,088,173	-	132,088,173
366	Underground Conduit	30,314,171	-	-	-	30,314,171	-	30,314,171
367	Undergrnd Conductr,Devices	127,486,910	-	-	-	127,486,910	-	127,486,910
368	Line Transformers	357,412,866	-	-	-	357,412,866	-	357,412,866
369	Services	97,942,819	(2,160,351)	216,035	-	95,998,504	-	95,998,504
370	Meters	89,106,213	-	-	-	89,106,213	(89,106,213)	-
370.3	Smart Meters Res	17,090,630	13,087,557	(1,308,756)	-	28,869,431	-	28,869,431
370.4	Smart Meters I	1,721,738	-	-	-	1,721,738	-	1,721,738
371	Inst. On Cust. Prem.	583,442	-	-	-	583,442	-	583,442
372	Leased Property Cust Premis	296,547	-	-	-	296,547	-	296,547
373.1	Street Light - Oh, Ug Lines	33,599,870	-	-	-	33,599,870	-	33,599,870
374	ARC Distribution	15,613	-	-	-	15,613	(15,613)	-
	TOTAL DISTRIBUTION PLANT	$ 1,947,737,525	$ 105,854,571	$ (10,585,457)	$ -	$ 2,043,006,639	$ (89,121,826)	$ 1,953,884,813

West Penn Power Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Plant-In-Service

Acct No	Description	Balance 4/30/15	Actual Activity Additions	Retirements	Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 1/0/00
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Easements	$ 293,153	$ -	$ -	$ -	$ 293,153	$ (41,511)	$ 251,643
390.1	Structures, Improvements	116,323,019	-	-	-	116,323,019	(16,471,340)	99,851,680
390.3	Struct Imprv, Leasehold Imp	1,554,625	-	-	-	1,554,625	(220,135)	1,334,490
391.1	Office Furn., Mech. Equip.	9,922,177	-	-	-	9,922,177	(1,404,980)	8,517,197
391.15	Office Machines	587,016	-	-	-	587,016	(83,121)	503,894
391.2	Data Processing Equipment	15,789,739	1,409,001	(140,900)	-	17,057,840	(2,415,390)	14,642,450
391.5	Pa Smart Meters H	9,343,348	3,989,486	(398,949)	-	12,933,885	-	12,933,885
392	Transportation Equipment	3,460,593	-	-	-	3,460,593	(490,020)	2,970,573
393	Stores Equipment	876,558	-	-	-	876,558	(124,121)	752,438
394	Tools, Shop, Garage Equip.	10,657,797	-	-	-	10,657,797	(1,509,144)	9,148,653
395	Laboratory Equipment	1,819,453	-	-	-	1,819,453	(257,634)	1,561,818
396	Power Operated Equipment	209,213	-	-	-	209,213	(29,625)	179,589
397	Communication Equipment	24,355,305	-	-	-	24,355,305	(12,908,312)	11,446,993
398	Misc. Equipment	2,464,648	-	-	-	2,464,648	(348,994)	2,115,654
399.1	ARC General Plant	735,526	-	-	-	735,526	(735,526)	-
	TOTAL GENERAL PLANT	$ 198,392,171	$ 5,398,487	$ (539,849)	$ -	$ 203,250,809	$ (37,039,852)	$ 166,210,957
	TOTAL	$ 2,601,747,538	$ 145,202,957	$ (13,115,543)	$ -	$ 2,733,834,952	$ (543,939,915)	$ 2,189,895,038

Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing
Response to OSBA Interrogatory Set II, No. 3
Witness: H. E. Stewart

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSYLVANIA POWER COMPANY
WEST PENN POWER COMPANY
DOCKET NOS. R-2014-2428745, R-2014-2428743, R-2014-2428744 and R-2014-2428742

Office of Small Business Advocate WP Set II, No. 3

"Reference "Demand Dollars" and "Customer Dollars" worksheets in the "Sum of Account" rows 218 to 221:

a. Is the formula for the sum for account 364 for customer costs incorrect?

b. Is for the sum for account 365 for demand costs incorrect?"

RESPONSE:

The formulas for these items were inadvertently each shifted by one row. Please see OSBA-WP-Set II-No. 2 Attachment A, lines 3.a. and 3.b. for the impact of this change.

Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing
Response to OSBA Interrogatory Set II, No. 2
Witness: H. E. Stewart

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSYLVANIA POWER COMPANY
WEST PENN POWER COMPANY
DOCKET NOS. R-2014-2428745, R-2014-2428743, R-2014-2428744 and R-2014-2428742

Office of Small Business Advocate WP Set II, No. 2

"Reference "Demand Allocators" worksheet in the electronic version of Exhibit HES-1:

a. Please confirm that DMS_NCP_SEC and DMD-NCP_PRI for the GSS class should be 75,175 and 9,717 kW respectively, rather than the 84,892 and 53,302 kW reported. If you cannot confirm, please explain why the GSS class primary plus secondary NCP demands do not sum to the total DMD_NCP."

RESPONSE:

The Companies confirm that DMD_NCP_SEC and DMD_NCP_PRI for the GSS class should be 75,175 and 9,717 kW respectively. Please see OSBA-WP-Set II-No. 2 Attachment A, line 2, for the impact of this change.

METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSYLVANIA POWER COMPANY
WEST PENN POWER COMPANY
DOCKET NOS. R-2014-2428745, R-2014-2428743, R-2014-2428744 and R-2014-2428742

Office of Small Business Advocate WP Set II, No. 4

"Reference Exhibit HES-1, electronic version, "Future Allocation Factors" and "Demand Allocators" worksheets, response to OSBA-I-19:

a. Is there an inconsistency in the treatment of sub-transmission customers for primary system demand and primary system customer allocation factors? Please explain your response, and address the following questions as part of your response:

   i. Do the primary NCP demand allocators include sub-transmission demands? Please explain your response.

   ii. Do the primary customer allocators include sub-transmission customers? Please explain your response.

   iii. Is it correct that Rate PP40 exhibits 6 primary customers and 793,035 kW in primary NCP demand?

b. Please describe the nature of the 52 GSS (Rate 20) and 23 GSM (Rate 30) customers who take service at sub-transmission voltage.

c. Please explain why GS Small customers represent some two-thirds of the primary system customer count.

d. Is there an inconsistency in the development of primary system customer and demand allocation factors for the Rate 20, 30 and 35 classes?

   i. Is it correct that the 94 GSM (Rate 30) primary customers represent 122,143 kW in NCP demand (nearly 1,300 kW per customer)?

   ii. Similarly, is it correct that the 2 GSL (Rate 35) customers represent 64,362 kW in NCP demand?

e. Please show how the 0.014% and 0.085% values in the response to OSBA-I-19(d) were calculated from the values reported in the electronic versions of Exhibit HES-1. Please reconcile the West Penn calculation to the 309 primary voltage (excluding sub-transmission) and 719,439 secondary voltage customers shown in the "Allocator Inputs" and "Future Allocation Factors" worksheets for Exhibit HES-1."

RESPONSE:

a. Yes, there is an inconsistency. The primary NCP demand allocators include sub-transmission demands, while the primary customer allocators inadvertently did not include sub-transmission customers. Please see OSBA-WP-Set II-No. 2 attachment A, line 4.a.ii., for the impact of including the sub-transmission customers in the primary customer allocators.

   i. Yes, the primary NCP demand allocators include sub-transmission demands.

   ii. The primary customer allocators inadvertently did not include sub-transmission customers. Please see OSBA-WP-Set II-No. 2 Attachment A, line 4.a.ii. for the impact of this change.

   iii. As stated in a.ii., the customer allocators inadvertently did not include sub-transmission customers. There are six primary customers, and 129 sub-transmission customers on Rate 40, which corresponds to the 793,035 kW of NCP demand. Please see OSBA-WP-Set II-No. 2 Attachment A, line 4.a.ii. for the impact of adding the 129 customers.

b. Please see response to part a.ii., as well as part c.

c. In order to produce the allocation factors for the proposed rate design, it was necessary to take the customer counts and NCP demands from current rate design and translate them into the proposed rate design categories (See OSBA-WP-Set I-No. 9 part f. for translation of the NCP demands). Under the proposed Cost of Service, customer counts and NCP demands were allocated to each rate schedule, as well as to the primary and secondary categories. As an alternative approach, the customer counts and NCP demands could have been directly assigned to the primary and secondary categories. Please see the table below for directly assigned primary and secondary categories. Please see OSBA-WP-Set I-No. 2 Attachment A, lines 4.c. and 4.d.ii. for the impact from these changes.

West Penn GS Rates - Primary vs Secondary

Directly Assigned Categories

	Customer Counts			NCP kW		
	GSS	GSM	GSL	GSS	GSM	GSL
Primary	40	136	200	47	12,491	183,684
Secondary	65,474	29,671	329	88,402	1,094,890	334,682
Total	65,514	29,807	529	88,449	1,107,381	518,366

d. As stated in part a, the primary NCP demand allocators include sub-transmission demands, while the primary customer allocators inadvertently did not include sub-transmission

Customers. Please see the response to part c for the development of primary system customer and demand allocation factors.

i. As shown in part c, a direct assignment of customers to the primary voltage results in 136 GSM customers who represent 12,491 kW in NCP demands (roughly 92 kW per customer).

ii. As shown in part c, a direct assignment of customers to the primary voltage results in 200 GSL customers, who represent 183,684 kW in NCP demands (roughly 918 kW per customer).

e. The percentages represent the primary customers used in the Primary/Secondary study.

Primary customers were identified from the GIS system by counting premises with the following rate codes.

PN	GPD, GPF, LPD, LPF	(458)
ME	GPD, GPF	(530)
PP	GPD, GPF	(123)
WPP	PP40D, PP40F, PP41D, PP44D, or PP46D	(103)

The total customers was collected from the FirstEnergy Facts at a Glance: Guide to Company Data publication. (August 15, 2014)

PN	590,000
ME	556,000
PP	162,000
WPP	719,000

Percentage Calculation

WPP 103/719,000 = 0.014%

Percentage of Other Regions (Non-WPP) =1111/1,308,000= 0.085%

As seen in the calculation above, West Penn inadvertently did not include the primary customers for rates 20 to 35 in the primary / secondary study. To see the impact of this change, please see ICG-WP-Set II-No. 2 Attachment A, line 4.e.

Exhibit No. ___(RAB-7)

WPP CORRECTED
CLASS COST OF SERVICE STUDY
Present Rates ($000s)

	TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL
RATE BASE							
Plant in Service	2,189,895	1,576,426	2,113	154,937	213,887	63,518	80,353
Depreciation Reserve	801,162	555,637	785	52,849	84,305	31,013	33,425
Net Plant	1,388,733	1,020,789	1,329	102,088	129,582	32,505	46,927
Rate Base Additions	180,164	129,827	174	12,672	17,770	5,285	6,712
Rate Base Deductions	301,371	212,292	303	25,536	30,221	9,767	10,466
Rate Base Other Total	(121,207)	(82,465)	(128)	(12,864)	(12,451)	(4,482)	(3,754)
Rate Base Total	1,267,526	938,324	1,201	89,224	117,131	28,023	43,174
INCOME STATEMENT							
Revenue							
Tariff Revenue Total	314,652	204,009	494	11,475	59,237	6,829	19,107
Other Revenue Total	14,431	10,935	13	1,258	1,099	342	306
Retail Total	329,083	214,944	507	12,733	60,337	7,171	19,414
Expenses							
Total Operation & Maintenance Expense	119,098	90,108	109	10,324	9,306	2,800	2,669
Depreciation Expense	70,865	51,198	74	5,636	6,759	1,867	2,562
Other Expenses Amortization Expense Total	11,896	8,172	17	1,205	1,265	428	560
Taxes Other than Income Taxes Excl GRT	6,234	4,466	6	495	586	199	206
Gross Receipts Tax	18,564	12,037	29	677	3,495	403	1,127
Total Operating Expense	226,657	165,980	234	18,337	21,412	5,697	7,123
Income Before Taxes	102,426	48,964	273	(5,603)	38,925	1,474	12,291
Income taxes							
Current State Income Tax	9,168	4,049	26	(624)	3,799	144	1,194
Current Federal Income Tax	28,913	12,770	83	(1,968)	11,981	454	3,765
Provision for Deferred Income Taxes	3,724	2,681	4	263	364	108	137
Investent Tax Credit Adjustments	(659)	(474)	(1)	(46)	(65)	(19)	(25)
Total Income Tax	41,146	19,027	112	(2,375)	16,079	686	5,071
Net Income After Tax	61,280	29,937	161	(3,229)	22,846	787	7,220
Rate of Return	4.83%	3.19%	13.38%	-3.62%	19.50%	2.81%	16.72%

WPP CORRECTED
CLASS COST OF SERVICE STUDY
Present Rates ($000s)

	POL	PSU	PP44	PP46	AGS	STLT
RATE BASE						
Plant in Service	13,509	4,765	990	22,130	38	57,229
Depreciation Reserve	4,048	2,404	489	11,171	14	25,022
Net Plant	9,461	2,361	501	10,959	24	32,207
Rate Base Additions	1,105	399	82	1,852	3	4,282
Rate Base Deductions	1,747	617	128	2,864	5	7,426
Rate Base Other Total	(641)	(218)	(46)	(1,012)	(2)	(3,144)
Rate Base Total	8,820	2,143	455	9,947	22	29,062
INCOME STATEMENT						
Revenue						
Tariff Revenue Total	3,945	1,084	28	2,399	15	6,031
Other Revenue Total	70	25	6	116	0	260
Retail Total	4,015	1,108	33	2,514	15	6,290
Expenses						
Total Operation & Maintenance Expense	636	192	43	893	2	2,016
Depreciation Expense	395	112	32	523	1	1,706
Other Expenses Amortization Expense Total	32	12	9	59	0	137
Taxes Other than Income Taxes Excl GRT	30	15	3	68	0	161
Gross Receipts Tax	233	64	2	142	1	356
Total Operating Expense	1,326	395	89	1,684	4	4,375
Income Before Taxes	2,689	713	(56)	830	11	1,915
Income taxes						
Current State Income Tax	258	71	(6)	81	1	175
Current Federal Income Tax	813	223	(18)	256	3	550
Provision for Deferred Income Taxes	23	8	2	38	0	97
Investent Tax Credit Adjustments	(4)	(1)	(0)	(7)	(0)	(17)
Total Income Tax	1,089	301	(22)	368	4	805
Net Income After Tax	1,600	412	(34)	462	6	1,110
Rate of Return	18.14%	19.23%	-7.41%	4.65%	28.46%	3.82%

West Penn Power
Summary of Pennsylvania Substations
2013 FERC Form 1

Character	VOLTAGE Primary	Secondary	Count	Substation Capacity in Mva
Distribution - U	0	0	21	(capacitors)
Distriution - U	0	0	1	
Distribution - U	25	4	1	3
Distribution - U	46	4	2	19
Distribution - U	25	4.16	1	10
Distribution - U	25	12.5	52	564
Distribution - U	26	12.5	1	7
Distribution - U	34.5	12.5	11	182
Distribution - U	46	12.5	29	825
Distubution - U	46	12.5	1	24
Distribution - U	69	12.5	2	44
Distribution - U	138	12.5	59	2,568
Distribution - U	230	12.5	1	11
Distribuiton - U	138	25	1	24
Distribution - U	138	25	27	1,873
Distribution -U	138	25	1	90
Distribution - U	138	34.5	3	170
Distribution - U	138	46	2	171
Distribution - U	230	46	3	444
Distribution - U	138	69	2	142
Distribution - U	230	138	1	224
Network	34.5	12.5	1	21
Network	46	12.5	1	45
Network	138	12.5	9	532
Network - U	138	12.5	1	102
Network	138	25	8	725
Network - U	138	25	1	187
Network	138	34.5	1	67
Network	138	46	1	80
Network	138	69	2	180
Transmission - U	138	4.16	1	14
Transmission - U	25	12.5	2	17
Transmission - U	46	12.5	1	11
Transmission	138	12.5	2	102
Transmission - U	138	12.5	4	169
Transmission- U	138	12.5	1	34
Transmission - U	69	25	1	39
Transmission - U	138	25	10	756
Transmission - U	115	46	1	60
Transmission	230	46	1	140
Transmission - U	230	46	1	280
Transmission - U	138	138	1	224
Transmission - U	230	138	1	224
Transmission - U	500	138	2	3,136

Total Distribution	200	7,395
Distribution with Secondary < 23 mV	160	4,257
	80.0%	57.6%

AK STEEL RECOMMENDED
CLASS COST OF SERVICE STUDY
Present Rates ($000s)

	TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL
RATE BASE							
Plant in Service	2,189,895	1,599,557	2,193	155,801	224,739	33,993	86,071
Depreciation Reserve	801,162	567,500	826	53,292	89,871	15,871	36,358
Net Plant	1,388,733	1,032,058	1,367	102,508	134,868	18,122	49,713
Rate Base Additions	180,164	131,767	181	12,745	18,680	2,809	7,192
Rate Base Deductions	301,371	215,292	313	25,648	31,628	5,938	11,208
Rate Base Other Total	(121,207)	(83,525)	(132)	(12,903)	(12,948)	(3,130)	(4,016)
Rate Base Total	1,267,526	948,533	1,236	89,605	121,920	14,993	45,697
INCOME STATEMENT							
Revenue							
Tariff Revenue Total	314,652	204,009	494	11,475	59,237	6,829	19,107
Other Revenue Total	14,431	11,042	14	1,262	1,149	206	333
Retail Total	329,083	215,051	508	12,737	60,387	7,035	19,440
Expenses							
Total Operation & Maintenance Expense	119,098	90,934	111	10,355	9,694	1,745	2,873
Depreciation Expense	70,865	51,730	76	5,656	7,009	1,187	2,693
Other Expenses Amortization Expense Total	11,896	8,227	17	1,207	1,291	358	574
Taxes Other than Income Taxes Excl GRT	6,234	4,532	6	497	617	115	222
Gross Receipts Tax	18,564	12,037	29	677	3,495	403	1,127
Total Operating Expense	226,657	167,460	239	18,392	22,106	3,808	7,489
Income Before Taxes	102,426	47,590	268	(5,655)	38,281	3,227	11,951
Income taxes							
Current State Income Tax	9,168	3,910	26	(629)	3,734	322	1,159
Current Federal Income Tax	28,913	12,330	82	(1,984)	11,774	1,016	3,656
Provision for Deferred Income Taxes	3,724	2,720	4	265	382	58	146
Investent Tax Credit Adjustments	(659)	(481)	(1)	(47)	(68)	(10)	(26)
Total Income Tax	41,146	18,479	110	(2,395)	15,822	1,386	4,936
Net Income After Tax	61,280	29,112	158	(3,260)	22,459	1,842	7,015
Rate of Return	4.83%	3.07%	12.77%	-3.64%	18.42%	12.28%	15.35%

AK STEEL RECOMMENDED
CLASS COST OF SERVICE STUDY
Present Rates ($000s)

	POL	PSU	PP44	PP46	AGS	STLT
RATE BASE						
Plant in Service	13,635	5,527	477	10,419	39	57,443
Depreciation Reserve	4,113	2,795	226	5,165	14	25,132
Net Plant	9,523	2,732	251	5,254	24	32,311
Rate Base Additions	1,116	463	39	870	3	4,300
Rate Base Deductions	1,763	715	61	1,346	5	7,454
Rate Base Other Total	(647)	(253)	(22)	(476)	(2)	(3,154)
Rate Base Total	8,876	2,479	229	4,779	23	29,157
INCOME STATEMENT						
Revenue						
Tariff Revenue Total	3,945	1,084	28	2,399	15	6,031
Other Revenue Total	70	28	3	62	0	261
Retail Total	4,016	1,112	31	2,460	15	6,291
Expenses						
Total Operation & Maintenance Expense	641	220	24	474	2	2,024
Depreciation Expense	398	130	21	253	1	1,711
Other Expenses Amortization Expense Total	32	14	8	31	0	137
Taxes Other than Income Taxes Excl GRT	30	17	2	35	0	161
Gross Receipts Tax	233	64	2	142	1	356
Total Operating Expense	1,334	444	57	935	4	4,389
Income Before Taxes	2,682	668	(25)	1,526	11	1,902
Income taxes						
Current State Income Tax	257	66	(3)	152	1	173
Current Federal Income Tax	810	209	(8)	479	3	546
Provision for Deferred Income Taxes	23	9	1	18	0	98
Investent Tax Credit Adjustments	(4)	(2)	(0)	(3)	(0)	(18)
Total Income Tax	1,086	283	(10)	645	4	800
Net Income After Tax	1,596	385	(15)	881	6	1,103
Rate of Return	17.98%	15.53%	-6.74%	18.43%	27.89%	3.78%

AK STEEL CCOSS
Recommended Revenue Allocation
West Penn Future Test Year ($000s)

		TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL
Rate Base Total		1,267,526	948,533	1,236	89,605	121,920	14,993	45,697
Tariff Revenue Total		314,652	204,009	494	11,475	59,237	6,829	19,107
Other Revenue Total		14,431	11,042	14	1,262	1,149	206	333
Retail Total Revenue		329,083	215,051	508	12,737	60,387	7,035	19,440
Total Operating Expense		226,657	167,460	239	18,392	22,106	3,808	7,489
Total Income Tax		41,146	18,479	110	(2,395)	15,822	1,386	4,936
Net Income After Tax - Present Rates		61,280	29,112	158	(3,260)	22,459	1,842	7,015
Rate of Return - Present Rates		4.83%	3.07%	12.77%	-3.64%	18.42%	12.28%	15.35%
Subsidy at Present Rates		0	30,418	(178)	13,789	(30,087)	(2,029)	(8,730)
Increase to Equal ROR - Requested	8.25%	78,623	89,254	(101)	19,347	(22,524)	(1,099)	(5,895)
Less: Remaining Subsidy	50%	(0)	(15,209)	89	(6,895)	15,043	1,014	4,365
Increase at 50% Subsidy Reduction		78,623	74,045	(12)	12,453	(7,481)	(84)	(1,530)
Eliminate Rate Decreases		0	(8,356)	12	(1,405)	7,481	84	1,530
Adjusted Increase		78,623	65,689	0	11,048	0	0	0
Adjustment to Limit GSS to 1.5 times Avg.		78,623	72,436	0	4,301	0	0	0
Company Proposed Increases		78,623	60,825	137	4,544	3,512	6,147	734
Subsidy at Company Proposed Rates		(0)	28,429	(238)	14,803	(26,036)	(7,246)	(6,629)
% Subsidy Reduction - Company Proposed			6.5%	-33.8%	-7.4%	13.5%	-257.2%	24.1%
Percent Increase - 50% Subs Red		25.0%	36.3%	-2.5%	108.5%	-12.6%	-1.2%	-8.0%
Adjusted Percent Increase		25.0%	32.2%	0.0%	96.3%	0.0%	0.0%	0.0%
Adjustment to Limit GSS to 1.5 times Avg.		25.0%	35.5%	0.0%	37.5%	0.0%	0.0%	0.0%
Percent Increase - WPP Proposed		25.0%	29.8%	27.7%	39.6%	5.9%	90.0%	3.8%

Exhibit No. ___(RAB-10)
Page 2 of 2

AK STEEL CCOSS
Recommended Revenue Allocation
West Penn Future Test Year ($000s)

		POL	PSU	PP44	PP46	AGS	STLT
Rate Base Total		8,876	2,479	229	4,779	23	29,157
Tariff Revenue Total		3,945	1,084	28	2,399	15	6,031
Other Revenue Total		70	28	3	62	0	261
Retail Total Revenue		4,016	1,112	31	2,460	15	6,291
Total Operating Expense		1,334	444	57	935	4	4,389
Total Income Tax		1,086	283	(10)	645	4	800
Net Income After Tax - Present Rates		1,596	385	(15)	881	6	1,103
Rate of Return - Present Rates		17.98%	15.53%	-6.74%	18.43%	27.89%	3.78%
Subsidy at Present Rates		(2,119)	(482)	48	(1,180)	(10)	558
Increase to Equal ROR - Requested	8.25%	(1,568)	(328)	62	(884)	(8)	2,366
Less: Remaining Subsidy	50%	1,059	241	(24)	590	5	(279)
Increase at 50% Subsidy Reduction		(509)	(87)	38	(294)	(3)	2,087
Eliminate Rate Decreases		509	87	(4)	294	3	(236)
Adjusted Increase		0	0	34	0	0	1,852
Adjustment to Limit GSS to 1.5 times Avg.		0	0	34	0	0	1,852
Company Proposed Increases		2,131	401	99	1,921	23	(1,852)
Subsidy at Company Proposed Rates		(3,699)	(729)	(37)	(2,805)	(32)	4,218
% Subsidy Reduction - Company Proposed		-74.6%	-51.4%	176.6%	-137.7%	-231.1%	-656.3%
Percent Increase - 50% Subs Red		-12.9%	-8.0%	136.9%	-12.2%	-23.0%	34.6%
Adjusted Percent Increase		0.0%	0.0%	121.5%	0.0%	0.0%	30.7%
Adjustment to Limit GSS to 1.5 times Avg.		0.0%	0.0%	121.5%	0.0%	0.0%	30.7%
Percent Increase - WPP Proposed		54.0%	37.1%	355.1%	80.1%	160.7%	-30.7%

CORRECTED WPP CCOSS
Recommended Revenue Allocation
West Penn Future Test Year ($000s)

		TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL
Rate Base Total		1,267,526	938,324	1,201	89,224	117,131	28,023	43,174
Tariff Revenue Total		314,652	204,009	494	11,475	59,237	6,829	19,107
Other Revenue Total		14,431	10,935	13	1,258	1,099	342	306
Retail Total Revenue		329,083	214,944	507	12,733	60,337	7,171	19,414
Total Operating Expense		226,657	165,980	234	18,337	21,412	5,697	7,123
Total Income Tax		41,146	19,027	112	(2,375)	16,079	686	5,071
Net Income After Tax - Present Rates		61,280	29,937	161	(3,229)	22,846	787	7,220
Rate of Return - Present Rates		4.83%	3.19%	13.38%	-3.62%	19.50%	2.81%	16.72%
Subsidy at Present Rates		(0)	28,021	(186)	13,700	(31,211)	1,031	(9,322)
Increase to Equal ROR - Requested	8.25%	78,623	86,224	(112)	19,234	(23,946)	2,769	(6,644)
Less: Remaining Subsidy	50%	0	(14,011)	93	(6,850)	15,606	(515)	4,661
Increase at 50% Subsidy Reduction		78,623	72,214	(19)	12,384	(8,340)	2,253	(1,983)
Eliminate Rate Decreases		0	(8,871)	19	(1,521)	8,340	(277)	1,983
Adjusted Increase		78,623	63,342	0	10,863	0	1,977	0
Adjustment to Limit GSS to 1.5 times Avg.		78,623	69,904	0	4,301	0	1,977	0
Company Proposed Increases		78,623	60,825	137	4,544	3,512	6,147	734
Subsidy at Company Proposed Rates		0	25,399	(249)	14,690	(27,458)	(3,379)	(7,378)
% Subsidy Reduction - Company Proposed			9.4%	-33.5%	-7.2%	12.0%	427.9%	20.9%
Percent Increase - 50% Subs Red		25.0%	35.4%	-3.8%	107.9%	-14.1%	33.0%	-10.4%
Adjusted Percent Increase		25.0%	31.0%	0.0%	94.7%	0.0%	28.9%	0.0%
Adjustment to Limit GSS to 1.5 times Avg.		25.0%	34.3%	0.0%	37.5%	0.0%	28.9%	0.0%
Percent Increase - WPP Proposed		25.0%	29.8%	27.7%	39.6%	5.9%	90.0%	3.8%

CORRECTED WPP CCOSS
Recommended Revenue Allocation
West Penn Future Test Year ($000s)

		POL	PSU	PP44	PP46	AGS	STLT
Rate Base Total		8,820	2,143	455	9,947	22	29,062
Tariff Revenue Total		3,945	1,084	28	2,399	15	6,031
Other Revenue Total		70	25	6	116	0	260
Retail Total Revenue		4,015	1,108	33	2,514	15	6,290
Total Operating Expense		1,326	395	89	1,684	4	4,375
Total Income Tax		1,089	301	(22)	368	4	805
Net Income After Tax - Present Rates		1,600	412	(34)	462	6	1,110
Rate of Return - Present Rates		18.14%	19.23%	-7.41%	4.65%	28.46%	3.82%
Subsidy at Present Rates		(2,132)	(560)	101	33	(10)	536
Increase to Equal ROR - Requested	8.25%	(1,585)	(428)	129	650	(8)	2,338
Less: Remaining Subsidy	50%	1,066	280	(51)	(17)	5	(268)
Increase at 50% Subsidy Reduction		(519)	(147)	79	634	(3)	2,070
Eliminate Rate Decreases		519	147	(10)	(78)	3	(254)
Adjusted Increase		0	0	69	556	0	1,816
Adjustment to Limit GSS to 1.5 times Avg.		0	0	69	556	0	1,816
Company Proposed Increases		2,131	401	99	1,921	23	(1,852)
Subsidy at Company Proposed Rates		(3,716)	(829)	30	(1,271)	(32)	4,190
% Subsidy Reduction - Company Proposed		-74.3%	-47.9%	70.0%	3894.6%	-229.4%	-682.4%
Percent Increase - 50% Subs Red		-13.2%	-13.6%	282.4%	26.4%	-23.4%	34.3%
Adjusted Percent Increase		0.0%	0.0%	247.7%	23.2%	0.0%	30.1%
Adjustment to Limit GSS to 1.5 times Avg.		0.0%	0.0%	247.7%	23.2%	0.0%	30.1%
Percent Increase - WPP Proposed		54.0%	37.1%	355.1%	80.1%	160.7%	-30.7%

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June 20, 2014

The Honorable Mark A. Hoyer
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street, 2nd Floor West
P.O. Box 3265
Harrisburg, PA 17105-3265

VIA E-MAIL AND FIRST CLASS MAIL

RE: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania; Docket No. R-2014-2406274, C-2014-2418801

Dear Judge Hoyer:

Enclosed please find two (2) copies of the Direct Testimony of Richard A. Baudino on behalf of the Columbia Industrial Intervenors ("CII") in the above-referenced proceeding.

As evidenced by the attached Certificate of Service, all parties to the proceeding are being served with a copy of this document. Thank you.

Sincerely,

McNEES WALLACE & NURICK LLC

By
Elizabeth P. Trinkle

Counsel to the Columbia Industrial Intervenors

EPT/emp
Enclosure
c: Rosemary Chiavetta, Secretary (Letter and Certificate of Service only - via electronic filing)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of 52 Pa. Code Section 1.54 (relating to service by a participant).

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Dated this 20th day of June, 2014, at Harrisburg, Pennsylvania.

CII Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2014-2406274
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE COLUMBIA INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.

JUNE 2014

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2014-2406274**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. INTRODUCTION

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 to 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 ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Columbia Industrial Intervenors ("CII").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to provide recommendations regarding cost allocation, revenue allocation, and rate design to the Pennsylvania Public Utility Commission ("PUC" or "Commission"). I will also respond to the Direct

Testimonies of Mr. Brian Elliott and Ms. Melissa J. Bell, witnesses for Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company").

Q. Please summarize your conclusions and recommendations to the Commission.

A. My conclusions and recommendations are as follows:

1. The Company's Customer/Demand class cost of service study ("CCOSS") is the most appropriate study to use for allocating cost responsibility to customer classes.

2. Based on the results from Columbia's Customer/Demand and Average CCOSSs, the LDS and MDS classes should receive little or no rate increase is this proceeding.

3. The rate of return for the LDS customer class is significantly understated in all of Columbia's CCOSSs. This is because of the large amount of flex rate volumes in the LDS class, which are significantly discounted from the Company's current LDS tariff rates. Consequently, none of Columbia's CCOSSs provide an accurate portrayal of the rate of return for LDS customers taking service at current full tariff rates.

4. Columbia's revenue allocation presentation does not accurately represent the Company's proposed rate impact on non-flex rate customers in the LDS class. ***The Company's non-flex rate customers would actually receive a 32% base rate increase under the Company's proposal, which is far higher than the Company's stated overall base rate increase of 21.4% for the LDS customer class.***

5. Columbia's proposal to allocate the costs associated with its proposed Choice Administration Charge ("CAC") should be rejected. Instead, I recommend that if the Commission adopts this charge, the associated costs should be allocated based on the number of customers receiving service under the Choice Program and Gas Distribution Service Program. The Company failed to show that these costs are incurred based on volumes consumed by customers.

II. CLASS COST OF SERVICE STUDIES

Q. Did you review Columbia's CCOSSs?

A. Yes. Company witness Brian Elliott sponsored three CCOSSs in his Direct Testimony. The studies are entitled "Customer/Demand," "Peak and Average," and "Average," which averages the results of the "Customer/Demand" and "Peak and Average" studies.

Q. Please provide a general description of the process of allocating cost responsibility to customer classes using a cost of service study.

A. A class cost of service study allocates and assigns the total cost of providing utility service to the classes of customers receiving that service. In certain instances, the subject utility can identify and directly assign costs to customers. For the vast majority of costs, however, such direct assignments are not possible and a cost of service study is required so that the remaining costs may be allocated to customers.

The development of a class cost of service study consists of three steps: functionalization, classification, and allocation. Step 1, functionalization, involves separating the utility's investment and expenses into major functional categories. For natural gas utilities such as Columbia, these categories may include production, storage, transmission, and distribution functions. Since Columbia is a distribution-only utility company, it does not have gas production and storage functions. The FERC Uniform System of Accounts provides the method by which costs are identified and placed into these various functional categories.

Step 2 is classification. Once functionalization is complete, the utility's costs are classified into demand, commodity, and customer components. Demand-related costs are fixed and do vary with the monthly and yearly gas commodity consumption of the utility's customers. These costs are driven by demands placed on the system during the winter peak period and include such items as gas main investment and expenses. Commodity-related expenses vary with the amount of gas consumed by customers and include the cost of gas and certain operation and maintenance expenses. Customer-related costs are associated with the number of customers and include items such as a portion of main investment, meters, and services.

Step 3 is allocation. After costs are classified, they are allocated to customer classes based on each class' contribution to the respective cost classifications. Generally speaking, demand costs are allocated based on each class' contribution to the total winter peak. Commodity costs are allocated based on each class' share of total yearly consumption, or throughput. Customer costs are allocated based on the number of customers.

Q. Are the classification and allocation methods for Columbia's investment in gas distribution mains an important component of a CCOSS?

A. Yes, most definitely. As Mr. Elliott pointed out on page 13 of his Direct Testimony, mains and services represent 88% of the Company's gross plant investment dollars. Thus, proper classification and allocation of these facilities is critical to ensure accurate results from a CCOSS.

Q. How should Columbia's investment in distribution mains be classified?

A. Distribution mains should be classified as both demand and customer related. Mr. Elliott presented such a CCOSS, the Customer/Demand study, in his Direct Testimony. This is the CCOSS I recommend the PUC adopt for purposes of customer class cost and revenue allocation in this proceeding.

Q. Please explain why distribution mains should be classified as both demand and customer related for purposes of the Company's CCOSS.

A. The two main functions of distribution mains are to deliver gas during the system winter peak and to connect customers to the system. A properly designed zero-intercept study or minimum size system study recognizes these two functions by classifying main costs into demand-related and customer-related costs, which can then be assigned to customer classes based on their respective contributions to system peak and on the number of customers in each class.

Peak winter demand is one of the primary drivers of Columbia's investment in gas distribution mains. The Company must have sufficient capacity available on its system to satisfy the peak winter heating demand, which is caused mainly by residential customers. If the peak winter demand increases, the Company may need to invest in additional mains to serve the load. During the non-winter months, substantial excess capacity exists on the system. Use of the Company's distribution system during these months does not cause additional fixed costs to be incurred by the Company. In fact, high load factor customers provide valuable margins to the

Company during off-peak months when the demands of residential heating customers are very low. In a similar manner to peak winter demand, if the number of customers increases, the Company may need to expand its distribution system investment. Thus, the number of customers connected to the distribution system is another important causative factor in distribution main investment. In my view, this is just obvious common sense in terms of the two factors that drive a gas distribution company's costs of distribution mains.

Q. Is it appropriate to classify and allocate a portion of the costs of mains on the basis of total throughput?

A. No. Peak winter demands and the number of customers drive investment in distribution mains, not gas consumption throughout the year. If the peak winter demand increases, the Company may need to invest in additional mains to serve the load. Likewise, if the number of customers increases, the Company may need to expand its distribution system investment. In my view, this is just obvious common sense in terms of the two factors that drive a gas distribution company's main costs.

Throughput, which varies substantially during the year, is not what causes Columbia's investment in the *fixed costs* of distribution mains. During the non-winter months, substantial excess capacity exists on the system. In fact, high load factor customers provide valuable margins to the Company during off-peak months when the demands of residential heating customers are very low.

Q. Have you prepared a table illustrating the effect of winter heating load on Columbia's system?

A. Yes. Table 1 below shows monthly consumption by major rate class for the twelve months ending November 30, 2013. I calculated the average monthly consumption for the heating and non-heating seasons from the data and included them in Table 1.

TABLE 1

MAJOR RATE CLASS MONTHLY CONSUMPTION (MDth)
Twelve Months Ended November 30, 2013

	Residential	Commercial	Industrial
December	4,424	2,716	1,892
January	6,109	3,586	1,911
February	6,354	3,882	1,993
March	5,842	3,452	1,923
April	4,250	2,599	1,906
May	1,551	1,203	1,791
June	922	841	1,690
July	582	676	1,729
August	548	716	1,668
September	587	747	1,671
October	777	891	1,743
November	2,406	1,788	1,980
Total	34,352	23,097	21,897
Monthly Avg. Heating Season	5,027	3,085	1,940
Monthly Avg., Non-Heating Season	1,317	1,096	1,743

Source: Columbia Gas of PA Exhibit No. 10, Schedule 2, Attachment 1, pg. 6 of 8

Note the dramatic increase in the average monthly heating season MDth for the Residential and Commercial classes (November - March). The Industrial class has a far more even usage pattern throughout the year and has little difference between heating and non-heating season average monthly consumption.

Q. Please summarize the results of the Customer/Demand CCOSS presented by Mr. Elliott.

A. Table 2 summarizes the customer class rates of return at current rates from the Customer/Demand study presented by Mr. Elliott.

TABLE 2

COLUMBIA GAS OF PA
CUSTOMER CLASS RATES OF RETURN
CUSTOMER/ DEMAND CCOSS

	% ROR	RELATIVE ROR
RS/RDS	4.221%	0.73
SGS/SGDS	9.043%	1.57
LGS	14.623%	2.54
SDS	17.123%	2.98
LDS	15.670%	2.73
MDS	205.408%	35.72
SYSTEM TOTAL	5.750%	

The Customer/Demand study shows that the Residential classes are not fully covering their cost to serve. All other classes are exceeding the cost to serve them.

The relative rate of return ratios provide a measure of each class' rate of return compared to Columbia's system average rate of return. A relative rate of return of less than 1.0 indicates that a rate class is providing less than the system average return. A relative rate of return greater than 1.0 indicates that a customer class is providing a rate of return greater than the system average. The Residential classes have a relative rate of return of 0.73, meaning that they are returning only 73% of the current system average return. ***Alternatively, the LDS class has a relative rate of return of 2.73, indicating a class rate of return 273% higher than the system average.***

Q. Mr. Baudino, is the current rate of return percentage and relative rate of return for the LDS class accurate?

A. No, it is not. This is because 47.6% of the volumes in the LDS class are discounted under flex rate contracts. In other words, nearly half of the total volumes in the LDS class are discounted from the Columbia's full tariff rates for this class. This means that all three of Columbia's CCOSSs understate the real rate of return for the LDS customers who are paying full tariff rates. Thus, the LDS customers paying the stated tariff rates are contributing a far higher percentage return and relative rate of return than the LDS class as a whole.

In conclusion, the Customer/Demand CCOSS shows that even with significant flex rate discounts, the LDS class would still require a rate decrease in order to reduce its class rate of return from 15.67% to the Company's requested return of 8.46%. In fact, this is the case with all non-residential rate classes.

Q. What do the results of the Customer/Demand CCOSS suggest with respect to the allocation of Columbia's requested revenue increase?

A. The CCOSS results show that the Residential classes should receive increases greater than the system average increase. The rest of Columbia's customer classes should receive either no increase or much smaller percentage increases that the overall system average increase.

III. REVENUE ALLOCATION AND RATE DESIGN

Q. Have you reviewed Columbia's revenue allocation and rate design proposals?

A. Yes. The Company's revenue allocation and rate design proposals are presented in the Direct Testimony of Ms. Melissa Bell. On page 20 of her Direct Testimony, Ms. Bell stated that the Company mostly relied upon the Average CCOSS, which I mentioned earlier, to provide guidance for Columbia's revenue allocation and rate design process.

Q. How does Ms. Bell propose to allocate the Company's proposed revenue increase in this proceeding?

A. Ms. Bell referred to Columbia's Exhibit No. 103, Schedule No. 8 for a summary of the average proposed percentage increases by rate class. Table 3 below shows the percentage base revenue and total revenue increases by customer class.

TABLE 3
COLUMBIA GAS OF PA
CLASS REVENUE INCREASES

	Total Rev. % Increase	Base Rev. % Increase
Residential Sales - RS, RDGSS	11.43%	20.99%
Small General Service - SGSS	9.74%	19.91%
Large General Sales Service - LGSS	3.86%	15.47%
Negotiated Sales Service - NSS	0.68%	0.01%
Residential Distribution Service (Choice) - RDS, RDGDS, RCC	11.43%	20.99%
Small Commercial Distribution Service (Choice) - SCD	9.74%	19.91%
Small General Distribution Service - SGDS	9.74%	19.91%
Small Distribution Service - SDS	5.72%	4.43%
Large Distribution Service - LDS	23.18%	21.44%
Main Line Distribution Service Class I - MLDS	0.68%	0.01%
Main Line Distribution Service Class II - MLDS	0.68%	0.01%
Total Revenues	11.09%	19.97%

Note that the total revenue increase column includes the effect of Columbia's proposed CAC, so the LDS class' actual revenue increase will be 23.18% over current non-gas revenues. As I stated earlier, Ms. Bell used the Company's Average CCOSS as a guide for her revenue allocation recommendation to the Commission. Since the Average CCOSS shows that the LDS class is currently below the system average rate of return (4.11%), Ms. Bell recommended a greater than average increase for LDS customers.

Q. Does the proposed revenue increase shown on Table 3 accurately portray the rate impact on the non-flex rate customers in the LDS class?

A. No, not at all. As I mentioned earlier in my testimony, 47.6% of the total Dth volumes in the LDS class are flexed and cannot be increased in this case. Therefore, all of the Company's proposed revenue increase for the LDS class will have to be collected from the full tariff LDS customers. Table 4 below shows the true rate impact on the LDS full tariff rate customers. Table 4 compares total non-flexed revenues at current rates with proposed rates including the proposed CAC.

TABLE 4

COLUMBIA GAS OF PA
PROPOSED REVENUE INCREASE
FULL TARIFF LDS CUSTOMERS

Current Full Tariff LDS customer revenues	9,832,457
Columbia proposed revenue increase	3,126,554
Proposed Full Tariff LDS customer revenues	12,959,011
Columbia proposed % Increase	31.8%

Q. Is Columbia's proposed revenue increase for the full tariff rate LDS customers reasonable?

A. Absolutely not. The 31.8% increase to the full tariff LDS customers is far greater than the increase to any other rate class. This is completely unjustified by the results of the Customer/Demand CCOSS. Moreover, the Company's Average CCOSS does not support such an extreme increase for the LDS class. I will explain this in greater detail later in my testimony.

Q. Did Ms. Bell attempt to adjust her revenue allocation proposal for the large amount of flexed volumes in the LDS class?

A. No. Ms. Bell simply presented the LDS class as a whole with no mention whatsoever of the impact of flexed rate volumes on the LDS class rate of return. She also failed to quantify the effect of her revenue allocation approach on the full tariff LDS customers in her testimony. Columbia's Exhibit No. 103 does show that the proposed increase to the LDS class is collected only from the full tariff rate customers, but omits the percentage impact on these customers.

Q. How did you determine that the Company's Average CCOSS does not support Ms. Bell's proposed revenue increase for the LDS class?

A. I took a similar approach to the one taken by Mr. John Skirtich in his Rebuttal Testimony (Columbia Statement No. 109-R) during the Company's last base rate case.[1] I have reproduced page 6 of that testimony and included it as Exhibit No. ___(RAB-2). On page 6, Mr. Skirtich discussed the rate adequacy of the LDS class under the Company's Customer/Demand study by calculating an average rate per Dth under full cost of service and comparing it to the average rate per Dth at current rates for all LDS customers and flex customers.

Since we do not have a CCOSS that separately calculates the costs to serve only the full tariff rate customers in the LDS class, it would be a reasonable approach to

1 *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2012-2321748, Rebuttal Testimony of John E. Skirtich (Jan. 28, 2013).

calculate the average full cost of service rate per Dth under Columbia's Average CCOSS and compare that rate to the current average rate per Dth for the full tariff customers. This will enable the parties and the Commission to assess whether or not full tariff LDS customers are paying their cost to serve and whether or not they would require an increase under the Company's Average CCOSS.

Q. Did you calculate the average rate per Dth under full cost of service for the LDS class?

A. Yes. Please refer to Exhibit No. ___(RAB-3). I created this exhibit using the Average CCOSS spreadsheet from the Company's Exhibit 111. The exhibit contains the Company's class revenues at proposed rates, and then adjusts each class' revenues based on applying the Company's requested system return of 8.46% to all classes. The resulting total revenues for the LDS class is $19.118 million, which represents the total cost to serve using the Company's Average CCOSS.

Table 5 below presents my calculation of the average Dth rate for the LDS class at full cost to serve and the current average rate per Dth for full tariff LDS customers. Note that the total revenue and Dth in Column (2) represent test year consumption for the LDS full tariff customers only.

TABLE 5

LDS AVERAGE RATE COMPARISON

AVERAGE CCOSS & CURRENT LDS RATES

	(1) AVERAGE CCOSS	(2) CURRENT LDS RATES
Total Cost to Serve (Revenues)	19,118,830	9,832,457
Total Dth	18,582,467	9,738,467
Average Rate / Dth	1.029	1.010
Increase from Current Avg. Rate		1.90%

Table 5 shows that the current average LDS tariff rate per Dth is only slightly lower than the average full cost of service rate under Columbia's Average CCOSS.

Q. Does the rate comparison in Table 5 support a 32% increase to full tariff LDS customers?

A. No. The rate comparison in Table 5 shows that full tariff LDS customers should only receive a 1.90% increase over current full tariff revenues under the Average CCOSS. In other words, the current average full tariff rate for the LDS class is only 1.90% less that the average full cost of service rate using the Company's Average CCOSS. A 32% rate increase cannot be supported for the full tariff rate LDS customers.

Q. What are your conclusions and recommendations with respect to Columbia's customer class revenue allocation in the proceeding?

A. I recommend that the Commission reject the Company's revenue allocation proposal. The Company's proposal results in an extreme and totally unjustified rate increase for full tariff rate customers in the LDS class.

Q. What is your recommendation for revenue allocation?

A. I recommend that the Commission base its customer class revenue allocation on the results of Columbia's Customer/Demand CCOSS. The LDS and MDS classes should receive no increase in this proceeding. The results of the Customer/Demand CCOSS also support no increases for the other non-residential rate schedules as well. It would be reasonable for the Residential classes to receive the entire amount of the Company's requested $54.1 million increase in this case. Exhibit No. ____(RAB-4) shows the results of the Customer/Demand study if the Residential classes are assigned the entire amount of Columbia's requested $54.1 million increase. The overall revenue increase to the Residential classes would be 15%, compared to the Company's overall requested increase of 11%. Total non-gas revenues for the Residential classes would increase by 25%, compared to an overall Company non-gas revenue increase of 18.1%. In the context of this case, the increase to the Residential classes is not unreasonable and is 1.36 times the overall increase.

However, if the Commission adopts the Company's Average CCOSS in this proceeding, then the full tariff LDS customers should only receive a 1.9% revenue increase. It is very important that this 1.90% revenue increase only be applied to the non-flexed, full tariff LDS customers rather than the entire LDS class. This is because flexed LDS customers would not receive any portion of a revenue increase assigned to the entire LDS class. As a result, the actual revenue increase to non-flexed, full tariff LDS customers would, of course, be much larger than 1.90% .

Q. **In Columbia's last rate case, Docket No. R-2012-2321748, you recommended that if the Commission chose to adopt the Demand/Commodity CCOSS that the increase to the LDS class be limited to 1.25 times the system average increase. Would this recommendation also be reasonable for the Residential classes in this case?**

A. Yes. An increase of 1.25 times the overall system average increase would result in a 22.6% increase to the Residential classes. The remaining revenues could then be spread to the non-residential classes using an equal percentage increase.

Q. **Briefly describe the Company's proposed Choice Administration Charge.**

A. Columbia seeks approval for a CAC for Choice Program and Gas Distribution Service Program customers for the costs associated with providing distribution service. According to Ms. Bell on page 29 of her Direct Testimony, these costs include labor and benefits, IT expense, and system expense associated with the Company's Aviator system.

Q. Do you agree with Ms. Bell's proposal to collect CAC revenues from its customers?

A. No. Ms. Bell developed a volumetric charge based on rate year distribution Dth less CAP and Flex Dth. This approach results in all distribution service customers paying a rate of $0.0248 per Dth.

However, Ms. Bell's proposed rate will result in higher volume customers paying a much greater share of the CAC costs than lower volumes users. Ms. Bell did not show that the CAC costs associated with labor and benefits, IT expense, and system expense associated with the Company's Aviator system vary with the amount of volumes a customer actually consumes. Larger customers will pay a far greater share of CAC costs, but the Company has not shown that these customers, simply by reason of higher consumption, cause these costs to increase. Thus, I recommend that the Commission reject Ms. Bell's proposed CAC.

Q. Do you have a recommended alternative to the design of the CAC if the PUC decides that such a charge is warranted in this proceeding?

A. Yes. But first, I wish to state that the CII takes no position on whether this charge should be implemented at this time. However, if the Commission does decide that a CAC should be implemented, I recommend that the charge be a fixed charge per customer. The charge should be designed by dividing total CAC costs by the total number of distribution customers. Table 6 presents the calculation of the CAC based on the number of distribution customers.

TABLE 6

CII PROPOSED
CHOICE ADMINISTRATION CHARGE ("CAC")

Rate Class	Total Bills
RDS	1,085,559
SCD	100,487
SGDS	26,550
SDS	4,617
LDS	902
MLDS	48
Total	1,218,163
Total CAC costs	$755,531
Monthly Charge per bill	$0.62

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-2014-2406274
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE COLUMBIA INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.

JUNE 2014

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
3/83	1780	NM	New Mexico Public Service Commission	Boles Water Co.	Rate design, rate of return.
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design.
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc.	PGE Industrial Intervenors	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Comm.	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.
11/01	U-25687	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112		AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661		Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01		Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103		Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
11/07	29797		Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Elec. Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR		Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy users Group	PECO Energy	Cost and revenue allocation, Tariff issues
07/08	R-2008-2039634	PA	PPL Gas Large Users Gp.	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation

**Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065		The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532		The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI		South Florida Hospital and Health Care Assn.	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana PSC	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Gp. Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation
03/10	09-1352-E-42T	WV	West Virginia Energy Users Gp.	Monongahela Power, Potomac Edison	Return on equity, rate of return
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Compay	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Gp.	Northern States Power	Cost and revenue allocation, rate design

Expert Testimony Appearances
of
Richard A. Baudino
As of November 2013

Date	Case	Jurisdict.	Party	Utility	Subject
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Svc. Of Colorado	Return on equity, wtd. cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Assn.	Florida Power and Light Co,	Return on equity, wtd. cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pannsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Gp.	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design

actual cost to serve such customers and the need to flex to avoid by-pass or fuel switching would be minimized.

Looking at the table below, the cost to serve LDS customers under the Company's Customer-Demand study is approximately $5.37 million. The average rate per DTH would be in the 30 cent range if set on the $5.37 million which is well below what Columbia is flexing on average at nearly 43 cents per DTH at current rates.

Table JES - 2			
	LDS @ Current Rates		
Item	Customer /Demand Study	All Customers	Flex Customers
Cost to Serve	5,367,000	12,850,848	3,369,813
Total Volume DTH	17,788,342	17,788,342	7,989,927
Average Rate per DTH	$0.3017	$0.7224	$0.4281

Q. Is Columbia recommending that the Commission adopt the Customer-Demand type studies in setting rates?

A. As I stated in my direct testimony, the use of more than one cost allocation methodology allows for the recognition of judgment and gives the Commission a useful range of results. I believe the Commission should consider the use of a range of cost studies results in evaluating class cost of service as the Company has presented. If the Commission concludes that a single study should be used that

COLUMBIA INDUSTRIAL INTERVENORS
CLASS REVENUES AT SYSTEM AVERAGE RATE OF RETURN
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2015

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL CDMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE		542,204,578	393,625,727	110,694,623	7,165,057	12,225,787	16,623,195	1,870,190
2	PRODUCTS PURCHASED		189,783,736	134,780,295	49,734,133	4,896,000	-	-	373,308
3	OPERATING & MAINTENANCE EXPENSES		157,805,570	125,308,645	21,010,583	713,320	3,958,123	6,787,178	27,721
4	DEPRECIATION & AMORTIZATION		46,522,945	34,085,704	7,726,790	254,344	1,617,095	2,817,318	21,695
5	TAXES OTHER THAN INCOME		3,494,437	2,611,732	555,209	18,411	114,212	194,216	658
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		397,606,688	296,786,376	79,026,714	5,882,075	5,689,430	9,798,712	423,382
7	OPERATING INCOME BEFORE TAXES		144,597,890	96,839,351	31,667,908	1,282,983	6,536,357	6,824,483	1,446,808
8	INCOME TAXES		44,644,804	29,160,259	10,444,022	427,327	2,175,648	1,842,497	595,053
9	INVESTMENT TAX CREDIT	12	(360,240)	(259,751)	(60,967)	(2,118)	(13,466)	(23,801)	(137)
10	NET INCOME TAXES		44,284,564	28,900,508	10,383,055	425,208	2,162,182	1,818,696	594,916
11	OPERATING INCOME		100,313,325	67,938,843	21,284,853	857,774	4,374,175	5,005,787	851,892
12	RATE BASE		1,185,793,357	848,550,196	208,794,073	8,424,968	42,921,083	76,691,923	411,113
13	RATE OF RETURN EARNED ON RATE BASE		8.460%	8.006%	10.194%	10.181%	10.191%	6.527%	207.216%
14	UNITIZED RETURN		1.00	0.95	1.21	1.20	1.20	0.77	24.49
15	Operating Income at Uniform System ROR		100,313,325	71,783,917	17,663,135	712,718	3,630,950	6,487,827	34,778
16	Operating Income difference from Columbia Proposed Revenues		(0)	3,845,073	(3,621,719)	(145,056)	(743,225)	1,482,040	(817,114)
17	Revenue Conversion factor		1.68391906	1.68391906	1.68391906	1.68391906	1.68391906	1.68391906	1.68391906
18	Revenue Increase (Decrease) Required from Columbia Proposed Revenues		(0)	6,474,793	(6,098,681)	(244,262)	(1,251,531)	2,495,635	(1,375,953)
19	Total Revenues at System Average Rate of return		542,204,578	400,100,519	104,595,941	6,920,795	10,974,256	19,118,830	494,237

LDS Total Volumes	18,582,467
LDS Average Dth Rate @ Full Cost of service	1.0288639
Current Average LDS Rate Full Tariff Rate	1.00965
Percentage Increase Required	1.90%

Exhibit No. ___(RAB-3)

COLUMBIA INDUSTRIAL INTERVENORS
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE		542,204,578	407,489,161	100,896,945	6,899,243	11,564,210	13,497,348	1,857,672
2	PRODUCTS PURCHASED		189,783,736	134,780,295	49,734,133	4,896,000	-	-	373,308
3	OPERATING & MAINTENANCE EXPENSES		157,805,570	132,304,138	18,965,621	492,073	2,721,213	3,294,967	27,559
4	DEPRECIATION & AMORTIZATION		46,522,945	37,005,114	6,905,145	160,924	1,091,067	1,339,000	21,695
5	TAXES OTHER THAN INCOME		3,494,437	2,807,345	500,176	12,152	78,952	95,153	658
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		397,606,688	306,896,892	76,105,075	5,561,150	3,891,232	4,729,120	423,219
7	OPERATING INCOME BEFORE TAXES		144,597,890	100,592,269	24,791,870	1,338,093	7,672,978	8,768,228	1,434,453
8	INCOME TAXES		44,644,804	29,498,849	8,030,489	486,251	2,836,761	3,202,323	590,131
9	INVESTMENT TAX CREDIT	12	(360,240)	(284,701)	(53,946)	(1,319)	(8,970)	(11,167)	(137)
10	NET INCOME TAXES		44,284,564	29,214,148	7,976,543	484,933	2,827,791	3,191,156	589,994
11	OPERATING INCOME		100,313,325	71,378,121	16,815,327	853,160	4,845,187	5,577,072	844,458
12	RATE BASE		1,185,793,357	929,717,022	185,948,302	5,830,600	28,296,581	35,589,739	411,113
13	RATE OF RETURN EARNED ON RATE BASE		8.460%	7.677%	9.043%	14.632%	17.123%	15.670%	205.408%
14	UNITIZED RETURN		1.00	0.91	1.07	1.73	2.02	1.85	24.28

Exhibit No. __(RAB-4)

SUMMARY OF THE CROSS-ANSWERING TESTIMONY OF RICHARD A. BAUDINO ON BEHALF OF THE LOUISIANA PUBLIC SERVICE COMMISSION

The purpose of the Cross-Answering Testimony of Mr. Richard A. Baudino is to address certain points raised in the Direct Testimony of Mr. Douglas Green, witness for the Staff of the Federal Energy Regulatory Commission ("FERC" or "Commission"). Mr. Baudino will also update his National Group of companies used for purposes of estimating the return on equity for Entergy, Arkansas, Inc.

Mr. Baudino first reviews Mr. Green's proposed proxy group and notes the selection criteria and the differences between Mr. Green's proxy group and Mr. Baudino's National Group. Their respective recommendations with respect to return on equity are quite similar even though they used different groups of companies. Mr. Baudino reviewed Mr. Green's criteria for excluding high and low return on equity results and found them consistent with FERC precedent. Mr. Baudino cautioned the use of the midpoint return on equity as a measure of central tendency, pointing out that it could be unduly influenced by outliers, and recommended using either the median or mean return on equity results from the Discounted Cash Flow ("DCF") model.

Mr. Baudino also noted that due to a recently announced merger, Cleco Corp. must now be excluded from his National Group. Mr. Baudino updated his DCF analyses excluding Cleco Corp. and updating stock prices, earnings growth forecasts, and other data. The results of this update were not significantly different from the DCF results in his Direct

Testimony and Mr. Baudino stated that his recommended return on equity of 9.0% will not change.

Mr. Baudino also updated the results of his Capital Asset Pricing Model ("CAPM") and concluded, consistent with Mr. Green's Direct Testimony, that unduly high earnings growth forecasts could be inflating the results of his forward-looking CAPM return on equity.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

CROSS-ANSWERING TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

NOVEMBER 7, 2014

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

CROSS-ANSWERING TESTIMONY OF RICHARD A. BAUDINO

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. Did you prepare and submit Direct Testimony in this proceeding?

A. Yes, I submitted Direct Testimony on behalf of the Louisiana Public Service Commission ("LPSC").

Q. What is the purpose of your Cross-Answering Testimony?

A. The purpose of my Cross-Answering Testimony is to respond to the Direct Testimony of Mr. Douglas Green, witness for the Staff of the Federal Energy Regulatory Commission ("FERC" or "Commission"). I will update my Discounted Cash Flow ("DCF") results to reflect more recent stock prices and growth forecasts and to remove Cleco Corp. from my National Group due to a recently announced merger. I will make a minor correction to my Capital Asset Pricing Model ("CAPM") analyses that I included in my Direct Testimony.

Q. With respect to the selection of companies contained in his proxy group, please summarize Mr. Green's approach.

A. Mr. Green described his selection criteria on pages 15 through 16 of his Direct Testimony. These criteria are:

- Operates in the continental United States and is classified by Value Line Investment Survey (hereinafter referred to as Value Line) as an electric utility company.
- Has a Standard & Poor's (S&P) Issuer Credit Rating ("ICR") of "BBB," and a Moody's credit rating within the "Baa" class of ratings.
- Has an S&P utility business risk profile of "excellent" or "strong."
- Has an S&P financial risk profile of "significant."
- Is currently paying a dividend, has not cut its dividend level within the six-month data period for the DCF analysis, and for whom Value Line does not forecast a dividend cut.
- Has no announced or pending significant merger, acquisition or spinoff activity during the recent six-month data period used in the DCF analysis.
- Has a five-year earnings growth estimate reported by the Institutional Brokers' Estimate System (IBES) through Yahoo! Finance.
- Has a DCF result that exceeds the most recent six-month average yield on Moody's "Baa" Public Utility bonds by at least 100 basis points.
- Has a DCF model growth rate (g) that is not higher than the proxy group's median average estimate of investors' true required return on equity (k).

Q. How do the selection criteria used by Mr. Green compare to the selection criteria you used to select your National Group?

A. Mr. Green's selection criteria have some similarities, but are more specific with respect to the inclusion of Standard and Poor's utility business risk profile of "excellent" or "strong" and a financial risk profile of "significant". Mr. Green also included criteria for DCF results that are at least 100 basis points above Moody's Baa bond yield and a DCF growth rate that is not higher than the group's median average estimate of investor's true required return on equity.

Q. How does your National Group compare to Mr. Green' group?

A. Mr. Green's proxy group has 10 companies compared to the 19 companies in my National Group and all the companies in Mr. Green's proxy group are contained in my National Group. Our DCF results and ultimate recommendations are nearly identical (8.95% for Mr. Green and 9.0% for my recommendation).

Q. Please comment on the DCF criteria for excluding low and high results.

A. Mr. Green's screening criteria for high and low return on equity results appear to be founded in FERC precedent. In my opinion, screening for outliers is critical if the analyst or the Commission relies on the midpoint of the results for the proxy group used for the analysis.

In this proceeding, the better measures of central tendency are the median and/or the mean no matter which proxy group the Commission chooses. The midpoint simply averages the high and low results, thus relying on only 2 DCF results for the entire group. If there are unusually high or low DCF results, they can skew the midpoint and lead to an unreliable and unrepresentative outcome. Thus, the median and/or mean represent superior measures for the Commission's consideration.

Q. On page 20 of his Direct Testimony, Mr. Green noted that the Commission has eliminated companies from proxy groups due to merger, acquisition, and or spin-off activity. Since you filed your Direct Testimony has any company in your National Group announced a merger or acquisition?

A. Yes. On October 20, 2014 Cleco Corporation announced that it entered into a definitive agreement to be acquired by a group of North American long-term infrastructure investors led by Macquarie Infrastructure and Real Assets and British Columbia Investment Management Corporation, along with other infrastructure investors[1]. Since Cleco Corporation is one of the companies in my National Group, it must now be eliminated from that group for purposes of estimating the return on equity for Entergy Arkansas, Inc.

Q. Did you perform an update to your return on equity analyses that excludes Cleco Corp.?

A. Yes. I excluded Cleco Corp. from my National Group of companies. Since the FERC prefers the use of the most recent data in return on equity analyses, I also updated stock prices for the six-month period from May through October 2014 and I updated the IBES and Zacks earnings growth estimates, which were obtained on October 31, 2014. I also included updated Value Line earnings and dividend growth forecasts from the October 31, 2014 report for companies in the Electric Utility (West) region. I also reviewed the Standard and Poor's and Moody's credit ratings for the companies in my National Group on October 31, 2014 and none of the ratings

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1 See http://investors.cleco.com/phoenix.zhtml?c=82212&p=RssLanding&cat=news&id=1979148.

had changed since I filed my Direct Testimony. Please see Exhibits LC-15 through LC-17 for updated results from the FERC's two-stage DCF model and for my constant growth DCF model.

Q. Did you review Mr. Green's calculation of the long-term growth in Gross Domestic Product ("GDP")?

A. Yes. Mr. Green presented his calculations of the long-term growth in GDP on Exhibit No. S-5, Schedule No. 5, page 5 of 12. Mr. Green included an updated IHS Global Insight GDP forecast. He also had slightly different GDP growth rates from the Energy Administration Association and the Social Security Administration. These differences were very slight and are attributable to a different starting year for the calculation of the respective growth rates. For purposes of my update I will adopt Mr. Green's average GDP growth rate of 4.37% because it includes an updated IHS Global Insight forecast.

Q. Did you update your CAPM analyses also?

A. Yes. I incorporated updated market returns from the summary statistics from the Value Line Investment Analyzer dated October 15, 2014. I also excluded Cleco Corp. from the National Group. During the update I discovered that CMS Energy's beta had been inadvertently omitted from the group average beta calculation, so I included CMS Energy in this update. I also used the average dividend yield with the median expected growth rates from the Value Line Investment Survey, rather than the median dividend yield, which is 0%. The CAPM results are shown in Exhibits LC-18 and LC-19. Note that I did not include the Treasury Yields for October 2014 because the historical data from the Federal Reserve had not been updated through October in time to include it in my updated analysis.

Q. Please summarize your updated return on equity result.

A. My updated return on equity results are summarized in Table 4.

TABLE 4
SUMMARY OF ROE ESTIMATES

FERC Two-Stage DCF:	
- Average	8.79%
- Median	8.96%
- Midpoint	9.09%
Baudino DCF Methodology:	
Average Growth Rates	
- High	9.45%
- Low	8.32%
- Average	8.98%
Median Growth Rates:	
- High	8.80%
- Low	8.03%
- Average	8.59%
CAPM:	
- 5-Year Treasury Bond	9.60%
- 20-Year Treasury Bond	9.93%
- Historical Returns	6.79% - 8.33%

Q. Based on your updated DCF results, do you still recommend a return on equity for Entergy Arkansas, Inc. of 9.0%?

A. Yes. The results using updated numbers did not significantly change from the results in my Direct Testimony.

Q. Your updated CAPM results are higher than in your Direct Testimony. Does this suggest that your DCF results are understated?

A. No. In fact, the forward-looking CAPM results are likely overstated.

Q. Why is this the case?

A. On pages 70 and 71 of his Direct Testimony, Mr. Green pointed out that Dr. Avera and Mr. McKenzie's estimate of the expected market return in their CAPM contained unsustainably high short-term and composite growth estimates. I then reviewed the summary statistics from the Value Line Investment Analyzer from which I took the median and average earnings and book value growth rates. This summary shows both high and low growth rates for the Value Line data set. For earnings growth, the high growth rate was 531.43% and the low growth rate was -23.5%. In my opinion, it is likely that unsustainably high growth rates could be skewing the average earnings and book value growth estimates. Thus, the median growth rates are probably more reasonable indices of central tendency than the average growth rates shown on page 2 of Exhibit LC-18. Using mean growth rates results in a market return of 11.16% compared to 12.88% using average growth rates. I have included the market return of 12.88% in the average market return calculation as I did in my Exhibit LC-10, but in my opinion this overstates the CAPM market return and the CAPM return on equity results somewhat. For this reason, historical risk premiums should also be used to frame the range of CAPM results in this proceeding.

Q. On page 71, lines 6 through 16 Mr. Green calculated a CAPM market return of 10.42% using long-term GDP growth in the calculation. Please comment on Mr. Green's testimony.

A. If the FERC uses GDP growth as the long-term growth component for the utilities it regulates, then I recommend the FERC consider using GDP growth as a component in the expected market return when the DCF model is used to estimate the market return component in the CAPM. Although I have not included forecasted GDP in my own CAPM analyses, Mr. Green's point is well taken and would result in both a lower expected market return and lower CAPM return on equity estimates.

Q. Does this complete your Direct Testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Arkansas, Inc.	)))	**Docket Nos. ER13-1508-001 *et al.***

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

NOVEMBER 7, 2014

1173947v1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
	)	

LC-18

1173860v1

NATIONAL GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	May-14
Ameren Corp.	High Price ($)	42.710	40.310	39.990	40.960	40.990	41.620
	Low Price ($)	38.250	37.530	36.650	38.440	37.670	37.940
	Avg. Price ($)	40.480	38.920	38.320	39.700	39.330	39.780
	Dividend ($)	0.400	0.400	0.400	0.400	0.400	0.400
	Mo. Avg. Div.	3.95%	4.11%	4.18%	4.03%	4.07%	4.02%
	6 mos. Avg.	4.06%					
American Electric Power	High Price ($)	58.610	53.880	53.710	55.910	55.940	54.060
	Low Price ($)	51.970	51.580	49.060	51.960	51.600	50.820
	Avg. Price ($)	55.290	52.730	51.385	53.935	53.770	52.440
	Dividend ($)	0.500	0.500	0.500	0.500	0.500	0.500
	Mo. Avg. Div.	3.62%	3.79%	3.89%	3.71%	3.72%	3.81%
	6 mos. Avg.	3.76%					
Avista Corp.	High Price ($)	35.960	32.880	32.470	33.600	33.580	32.940
	Low Price ($)	30.550	30.450	30.350	31.020	30.380	30.900
	Avg. Price ($)	33.255	31.665	31.410	32.310	31.980	31.920
	Dividend ($)	0.318	0.318	0.318	0.318	0.318	0.318
	Mo. Avg. Div.	3.82%	4.02%	4.05%	3.94%	3.98%	3.98%
	6 mos. Avg.	3.97%					
Black Hills Corp.	High Price ($)	55.110	54.050	53.890	62.130	61.410	60.380
	Low Price ($)	47.110	47.870	50.390	52.700	57.020	55.230
	Avg. Price ($)	51.110	50.960	52.140	57.415	59.215	57.805
	Dividend ($)	0.390	0.390	0.390	0.390	0.390	0.390
	Mo. Avg. Div.	3.05%	3.06%	2.99%	2.72%	2.63%	2.70%
	6 mos. Avg.	2.86%					
CMS Energy	High Price ($)	32.910	30.830	30.540	31.200	31.230	30.430
	Low Price ($)	29.590	29.150	27.900	28.870	28.970	28.700
	Avg. Price ($)	31.250	29.990	29.220	30.035	30.100	29.565
	Dividend ($)	0.270	0.270	0.270	0.270	0.270	0.270
	Mo. Avg. Div.	3.46%	3.60%	3.70%	3.60%	3.59%	3.65%
	6 mos. Avg.	3.60%					
El Paso Electric	High Price ($)	38.260	39.410	39.420	40.430	40.330	38.420
	Low Price ($)	35.340	36.050	35.390	36.810	36.670	35.210
	Avg. Price ($)	36.800	37.730	37.405	38.620	38.500	36.815
	Dividend ($)	0.280	0.280	0.280	0.280	0.280	0.265
	Mo. Avg. Div.	3.04%	2.97%	2.99%	2.90%	2.91%	2.88%
	6 mos. Avg.	2.95%					

NATIONAL GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	May-14
Empire District Elec.	High Price ($)	29.240	25.950	26.000	25.870	25.710	24.420
	Low Price ($)	24.090	24.000	24.020	24.360	23.560	23.230
	Avg. Price ($)	26.665	24.975	25.010	25.115	24.635	23.825
	Dividend ($)	0.255	0.255	0.255	0.255	0.255	0.255
	Mo. Avg. Div.	3.83%	4.08%	4.08%	4.06%	4.14%	4.28%
	6 mos. Avg.	4.08%					
Entergy Corp.	High Price ($)	84.580	78.370	77.450	82.480	82.300	75.690
	Low Price ($)	76.510	75.290	70.700	72.810	75.420	71.680
	Avg. Price ($)	80.545	76.830	74.075	77.645	78.860	73.685
	Dividend ($)	0.830	0.830	0.830	0.830	0.830	0.830
	Mo. Avg. Div.	4.12%	4.32%	4.48%	4.28%	4.21%	4.51%
	6 mos. Avg.	4.32%					
Great Plains Energy	High Price ($)	27.000	25.800	25.910	26.950	27.050	27.280
	Low Price ($)	24.110	23.910	24.090	24.710	24.720	24.970
	Avg. Price ($)	25.555	24.855	25.000	25.830	25.885	26.125
	Dividend ($)	0.230	0.230	0.230	0.230	0.230	0.230
	Mo. Avg. Div.	3.60%	3.70%	3.68%	3.56%	3.55%	3.52%
	6 mos. Avg.	3.60%					
Hawaiian Electric	High Price ($)	28.270	26.890	25.410	25.380	25.650	24.400
	Low Price ($)	26.040	24.910	22.710	23.440	23.630	23.040
	Avg. Price ($)	27.155	25.900	24.060	24.410	24.640	23.720
	Dividend ($)	0.310	0.310	0.310	0.310	0.310	0.310
	Mo. Avg. Div.	4.57%	4.79%	5.15%	5.08%	5.03%	5.23%
	6 mos. Avg.	4.97%					
IDACORP	High Price ($)	64.120	56.970	56.800	58.790	57.860	56.370
	Low Price ($)	53.390	53.200	51.700	53.550	53.780	52.910
	Avg. Price ($)	58.755	55.085	54.250	56.170	55.820	54.640
	Dividend ($)	0.430	0.430	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	2.93%	3.12%	3.17%	3.06%	3.08%	3.15%
	6 mos. Avg.	3.09%					
Otter Tail Corp.	High Price ($)	31.200	28.700	28.910	30.430	30.300	29.520
	Low Price ($)	26.530	26.670	27.160	27.900	28.260	27.190
	Avg. Price ($)	28.865	27.685	28.035	29.165	29.280	28.355
	Dividend ($)	0.303	0.303	0.303	0.303	0.303	0.303
	Mo. Avg. Div.	4.20%	4.38%	4.32%	4.16%	4.14%	4.27%
	6 mos. Avg.	4.24%					

NATIONAL GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Oct-14	Sep-14	Aug-14	Jul-14	Jun-14	May-14
PG&E Corp.	High Price ($)	50.360	48.240	46.480	48.090	48.640	45.990
	Low Price ($)	44.170	43.760	42.920	44.650	45.270	42.850
	Avg. Price ($)	47.265	46.000	44.700	46.370	46.955	44.420
	Dividend ($)	0.455	0.455	0.455	0.455	0.455	0.455
	Mo. Avg. Div.	3.85%	3.96%	4.07%	3.92%	3.88%	4.10%
	6 mos. Avg.	3.96%					
PNM Resources	High Price ($)	29.330	26.970	26.250	29.940	29.330	29.220
	Low Price ($)	24.810	24.760	24.260	25.640	27.600	26.190
	Avg. Price ($)	27.070	25.865	25.255	27.790	28.465	27.705
	Dividend ($)	0.185	0.185	0.185	0.185	0.185	0.185
	Mo. Avg. Div.	2.73%	2.86%	2.93%	2.66%	2.60%	2.67%
	6 mos. Avg.	2.74%					
Public Service Ent. Gp.	High Price ($)	41.630	38.320	37.410	40.680	40.930	41.350
	Low Price ($)	36.370	36.040	34.050	35.110	37.060	36.910
	Avg. Price ($)	39.000	37.180	35.730	37.895	38.995	39.130
	Dividend ($)	0.370	0.370	0.370	0.370	0.370	0.370
	Mo. Avg. Div.	3.79%	3.98%	4.14%	3.91%	3.80%	3.78%
	6 mos. Avg.	3.90%					
SCANA Corp.	High Price ($)	55.250	52.230	51.940	53.890	53.880	53.830
	Low Price ($)	47.770	48.810	48.530	50.780	49.510	50.440
	Avg. Price ($)	51.510	50.520	50.235	52.335	51.695	52.135
	Dividend ($)	0.525	0.525	0.525	0.525	0.525	0.525
	Mo. Avg. Div.	4.08%	4.16%	4.18%	4.01%	4.06%	4.03%
	6 mos. Avg.	4.09%					
Sempra Energy	High Price ($)	111.360	107.810	106.090	104.600	105.250	100.690
	Low Price ($)	98.340	102.340	96.130	99.600	98.320	96.580
	Avg. Price ($)	104.850	105.075	101.110	102.100	101.785	98.635
	Dividend ($)	0.660	0.660	0.660	0.660	0.660	0.660
	Mo. Avg. Div.	2.52%	2.51%	2.61%	2.59%	2.59%	2.68%
	6 mos. Avg.	2.58%					
Westar Energy	High Price ($)	37.910	37.070	37.090	38.230	38.240	36.100
	Low Price ($)	33.730	33.760	34.530	36.040	35.220	34.720
	Avg. Price ($)	35.820	35.415	35.810	37.135	36.730	35.410
	Dividend ($)	0.350	0.350	0.350	0.350	0.350	0.350
	Mo. Avg. Div.	3.91%	3.95%	3.91%	3.77%	3.81%	3.95%
	6 mos. Avg.	3.88%					
Average Dividend Yield		3.70%					

Source: Yahoo! Finance

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
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NATIONAL GROUP
DCF RETURN ON EQUITY WITH FERC TWO-STAGE GROWTH

(1)	(2) Dividend Yield	(3) Adjustment	(4) Expected Div. Yield	(5) IBES Growth	(6) GDP Growth	(7) FERC Weighted Growth	(8) ROE	
Ameren Corp.	4.06%	1.037	4.21%	8.90%	4.37%	7.39%	11.60%	
American Elec Pwr	3.76%	1.024	3.85%	4.97%	4.37%	4.77%	8.62%	
Avista Corp.	3.97%	1.024	4.06%	5.00%	4.37%	4.79%	8.85%	
Black Hills Corp.	2.86%	1.031	2.95%	7.00%	4.37%	6.12%	9.07%	
CMS Energy Corp.	3.60%	1.030	3.71%	6.80%	4.37%	5.99%	9.70%	
El Paso Electric	2.95%	1.031	3.04%	7.00%	4.37%	6.12%	9.16%	
Empire District Elec	4.08%	1.017	4.15%	3.00%	4.37%	3.46%	7.61%	
Entergy Corp.	4.32%	1.013	4.37%	1.66%	4.37%	2.56%	6.94%	
Great Plains Energy	3.60%	1.024	3.69%	5.00%	4.37%	4.79%	8.48%	
Hawaiian Elec.	4.97%	1.021	5.08%	4.00%	4.37%	4.12%	9.20%	
IDACORP, Inc.	3.09%	1.021	3.15%	4.00%	4.37%	4.12%	7.27%	
Otter Tail Corp.	4.24%	1.027	4.36%	6.00%	4.37%	5.46%	9.82%	
PG&E Corp.	3.96%	1.030	4.08%	6.95%	4.37%	6.09%	10.17%	
PNM Resources	2.74%	1.035	2.84%	8.32%	4.37%	7.00%	9.84%	
Pub Sv Enterprise Grp	3.90%	1.013	3.95%	1.75%	4.37%	2.62%	6.57%	
SCANA Corp.	4.09%	1.023	4.18%	4.60%	4.37%	4.52%	8.70%	
Sempra Energy	2.58%	1.032	2.67%	7.47%	4.37%	6.44%	9.10%	
Westar Energy	3.88%	1.018	3.95%	3.20%	4.37%	3.59%	7.54%	
Averages	3.70%		3.79%	5.31%	4.37%	5.00%	8.79%	
Median							8.96%	
Range of ROE Values						6.57%	-	11.60%
Midpoint of ROE range							9.09%	

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BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Entergy Arkansas, Inc.	)	**Docket Nos. ER13-1508-001 *et al.***
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NATIONAL GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
Ameren Corp.	2.00%	4.50%	4.00%	8.30%	8.90%
American Elec Pwr	4.50%	4.50%	4.00%	4.90%	4.97%
Avista Corp.	4.50%	5.50%	3.00%	5.00%	5.00%
Black Hills Corp.	4.00%	9.50%	4.00%	7.00%	7.00%
CMS Energy Corp.	6.00%	6.50%	6.00%	6.10%	6.80%
El Paso Electric	7.00%	3.00%	5.00%	3.50%	7.00%
Empire District Elec	4.50%	4.00%	3.50%	3.00%	3.00%
Entergy Corp.	2.50%	1.00%	4.00%	-1.00%	1.66%
Great Plains Energy	6.00%	6.00%	3.00%	5.00%	5.00%
Hawaiian Elec.	1.00%	4.00%	3.50%	4.00%	4.00%
IDACORP, Inc.	8.00%	1.50%	3.50%	4.00%	4.00%
Otter Tail Corp.	1.50%	15.50%	5.00%	6.00%	6.00%
PG&E Corp.	2.50%	5.00%	2.50%	6.10%	6.95%
PNM Resources	12.00%	11.00%	5.00%	8.50%	8.32%
Pub Sv Enterprise Grp	2.50%	2.00%	5.00%	2.30%	1.75%
SCANA Corp.	3.00%	5.00%	4.50%	4.40%	4.60%
Sempra Energy	7.00%	7.00%	5.50%	7.50%	7.47%
Westar Energy	3.00%	6.00%	4.50%	3.80%	3.20%
Averages excluding negative values	4.53%	5.64%	4.19%	5.26%	5.31%
Median Values	4.25%	5.00%	4.00%	4.95%	5.00%

Sources: Value Line Investment Survey, August 22, September 19, and October 31, 2014
Yahoo! Finance for IBES growth rates retrieved October 31, 2014
Zacks growth rates retrieved October 31, 2014
IBES growth rates were used in the Zacks column for Avista, Black Hills, and Otter Tail.

NATIONAL GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.70%	3.70%	3.70%	3.70%	3.70%
Average Growth Rate	4.53%	5.64%	5.26%	5.31%	5.18%
Expected Div. Yield	3.79%	3.81%	3.80%	3.80%	3.80%
DCF Return on Equity	***8.32%***	***9.45%***	***9.06%***	***9.11%***	***8.98%***
Method 2:					
Dividend Yield	3.70%	3.70%	3.70%	3.70%	3.70%
Median Growth Rate	4.25%	5.00%	4.95%	5.00%	4.80%
Expected Div. Yield	3.78%	3.80%	3.79%	3.80%	3.79%
DCF Return on Equity	***8.03%***	***8.80%***	***8.74%***	***8.80%***	***8.59%***

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NATIONAL GROUP
Capital Asset Pricing Model Analysis
20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.98%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	3.09%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.88%
6	National Group Beta	0.77
7	National Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.83%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.93%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.98%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.68%
4	Risk Premium	
5	(Line 1 minus Line 3)	10.30%
6	National Group Beta	0.77
7	National Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.92%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.60%

NATIONAL GROUP
Capital Asset Pricing Model Analysis
Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
April-14	3.27%
May-14	3.12%
June-14	3.15%
July-14	3.07%
August-14	2.94%
September-14	3.01%
6 month average	3.09%

5 Year Treasury Bond Data

	Avg. Yield
April-14	1.70%
May-14	1.59%
June-14	1.68%
July-14	1.70%
August-14	1.63%
September-14	1.77%
6 month average	1.68%

Value Line Market Growth Rate Data:

Forecasted Data:

Value Line Average Growth Rates:	
Earnings	14.37%
Book Value	9.83%
Average	12.10%
Average Dividend Yield	0.78%
Estimated Market Return	12.88%
Value Line Median Growth Rates:	
Earnings	12.00%
Book Value	8.75%
Average	10.38%
Average Dividend Yield	0.78%
Estimated Market Return	11.16%
Value Line Projected 3-5 Yr. Annual Total Return	11.89%
Average of Projected Mkt. Returns	11.98%

Source: Value Line Investment Survey for Windows retreived October 15, 2014

National Group Betas:	Value Line
Ameren Corp.	0.75
American Elec Pwr	0.70
Avista Corp.	0.80
Black Hills Corp.	0.90
CMS Energy	0.75
El Paso Electric	0.70
Empire District Elec	0.65
Entergy Corp.	0.70
Great Plains Energy	0.85
Hawaiian Elec.	0.80
IDACORP, Inc.	0.80
Otter Tail Corp.	0.95
PG&E Corp.	0.65
PNM Resources	0.85
Pub Sv Enterprise Grp	0.75
SCANA Corp.	0.75
Sempra Energy	0.75
Westar Energy	0.75
Average	0.77

Source: Value Line Investment Survey

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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NATIONAL GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%
Long-Term Annual Income Return on Long-Term Government Bonds	5.30%	5.30%
Historical Market Risk Premium	4.80%	6.80%
National Group Beta, Value Line	0.77	0.77
Beta * Market Premium	3.69%	5.23%
Current 20-Year Treasury Bond Yield	3.09%	3.09%
CAPM Cost of Equity, Value Line Beta	**6.79%**	**8.33%**

Source: *Ibbotson SBBI 2014 Classic Yearbook,* Morningstar, pp. 39 - 40.

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, to Conduct a Biennial Review of Costs and Rates - Test Year 2015	Docket No. 05-UR-107

SURREBUTTAL TESTIMONY OF RICHARD A. BAUDINO

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. Did you submit Direct and Rebuttal Testimony in this proceeding?

A. Yes, I submitted both Direct and Rebuttal Testimony on behalf of the Wisconsin Industrial Energy Group, Inc. ("WIEG").

Q. What is the purpose of your Surrebuttal Testimony?

A. I respond to the Rebuttal Testimony submitted by Mr. Jonathan Wallach on behalf of the Citizens Utility Board ("CUB"). I also address Public Service Commission of Wisconsin Staff's ("Staff') response to WIEG's discovery request regarding Staff's Real Time Market Price ("RTMP") study.

Q. At Rebuttal-CUB-Wallach-6, Mr. Wallach presents his revenue allocation proposal. Should the Commission accept Mr. Wallach's revenue allocation recommendation presented in his Table 2?

A. No. Mr. Wallach supported the Staff's class cost of service study ("CCOSS") Scenario 4, which employed (1) an equivalent peaker ("EP") method to classify and allocate production plant costs and (2) classified certain distribution plant accounts as 100% demand. Mr. Wallach also testified that his revenue allocation proposal for residential and small commercial and industrial was consistent with Staff Scenarios 2, 3, and 4.

For the reasons I stated in my Rebuttal Testimony, the Commission should reject Staff's CCOSS Scenario 4. Mr. Wallach presented no new evidence in support of the EP method to classify and allocate production plant costs.

Q. On Rebuttal-CUB-Wallach-10, lines 3 through 6, Mr. Wallach testified, "the fixed costs incurred for baseload or intermediate capacity over and above those incurred for peaking capacity are appropriately classified as energy-related…" Please respond to Mr. Wallach's position.

A. Mr. Wallach's position on this point is fundamentally flawed and should be rejected by the Commission.

Mr. Wallach has presented absolutely no system planning studies that suggest that Wisconsin Electric Power Company ("WEPCO" or "Company") invested in the additional capital costs of its intermediate and base load generating capacity for the sole purpose of achieving fuel savings. Lacking this basic support, Mr. Wallach miscast the additional capital costs of WEPCO's intermediate and base load units as "capitalized energy costs." For the reasons I presented in my Direct and Rebuttal Testimonies, WEPCO's production plant costs should be classified as 100% demand related and allocated based on the 4CP method.

Q. On Rebuttal-CUB-Wallach-10, line 20, Mr. Wallach testified that your concern regarding inefficient price signals is one of rate design, not cost allocation. Is he correct on this point?

A. No, he is quite incorrect. High load factor customers in the Large classes are harmed by the inequitable and inefficient allocation of costs inherent in the EP method endorsed by Mr. Wallach. Inefficient price signals inevitably follow from the application of the EP methodology, or any class cost of service study ("CCOSS") that employs an energy-based allocation of fixed production costs. Contrary to Mr. Wallach's assertion, rate design cannot compensate for a faulty CCOSS method that assigns a disproportionate share of cost responsibility to large, higher load factor customers.

Q. Did Staff respond to WIEG's discovery regarding its RTMP study?

A. Yes. Staff provided work papers and its statistical analyses in response to WIEG's discovery on September 15, 2014.

Q. Based on your review of Staff's work papers and supporting documents, does your conclusion regarding the usefulness of Staff's RTMP study remain the same?

A. Yes. Staff's RTMP study has no real value in assisting the Commission in its decision regarding extending the RTMP tariff as proposed by Mr. Rogers.

More specifically, Staff's statistical analyses fail to support why these studies were even performed in the first place. For example, on Direct-PSC-Singletary-44, Mr. Singletary testified that Staff's analysis indicated that RTMP customer growth rates were not significantly different from non-RTMP customers. However, witness Singletary's regression results indicate that the model is not statistically significant—in other words, his hypothesis that the customer growth rates between RTMP and non-RTMP customers are not significantly different, is rejected. For arguments sake, even if correct, similar customer growth rates for RTMP and non-RTMP customers neither supports nor indicts the RTMP program. The fact is that RTMP customers showed growth in Staff's study. More importantly, however, Mr. Rogers presented an analysis in his Rebuttal Testimony showing that RTMP customers have had growth significantly greater than non-RTMP customers.[1] Mr. Rogers' analysis, which showed total growth of 22% in usage for RTMP customers calls Mr. Singletary's analysis into serious question.

Mr. Rogers also presented a more complete picture of the RTMP program, showing that RTMP customers added 1,247 new jobs. Indeed, I concur with Mr. Rogers' conclusion on Rebuttal-WEPCO/WG-Rogers-47 that an extra three years for the RTMP program would allow a smoother transition off of the RTMP tariff for existing customers. This is an especially important consideration since the Commission just expanded the RTMP program last year.

Q. Does this complete your Rebuttal Testimony?

A. Yes.

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[1] Please refer to Rebuttal-WEPCO/WG-Rogers-44 through 47 of Mr. Rogers' Rebuttal Testimony for a complete discussion of WEPCO's finding regarding RTMP and non-RTMP customer growth.