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BEFORE THE ARIZONA CORPORATION COI

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AZ CORP COMMISSION
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	Docket No. E-04204A-15-0142

Arizona Corporation Commission
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RUCO'S NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Robert Mease and Jeffrey Michlik, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 6th day of November, 2015.

Daniel W. Pozefsky
Chief Counsel

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of November, 2015 with:

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Cheryl Fraulob

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

DIRECT TESTIMONY
OF
ROBERT B. MEASE
ON
COST OF CAPITAL

ON BEHALF OF THE
RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2015

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of UNS Electric, Inc.'s ("UNSE") application for a permanent rate increase, filed with the Arizona Corporation Commission ("ACC" or "Commission") on May 4, 2015, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt an 8.35 percent cost of common equity. This 8.35 percent figure is the result obtained from the Discounted Cash Flow model ("DCF") and the Capital Asset Pricing Model ("CAPM") used in RUCO's cost of equity analysis, and is 200 basis points lower than UNSE's proposed 10.35 percent cost of common equity.

Cost of Debt – RUCO recommends that the Commission adopt the actual cost of long-term debt of 4.66 percent which is UNSE's actual end of test year cost of long-term debt. This compares to the cost of debt previously approved in Decision No. 74235 of 5.47 percent.

Capital Structure – RUCO recommends that the Commission adopt UNSE's actual end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Original Cost Rate of Return – RUCO recommends that the Commission adopt a 6.86 percent weighted average cost of capital as the original cost rate of return for UNSE. This compares to the Company's requested weighted average original cost of capital of 8.13 percent.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 5.26 percent for UNSE, which is RUCO's 6.61 percent original cost rate of return minus RUCO's recommended inflation adjustment of 1.35 percent. The method used by RUCO to arrive at this 6.61 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in prior UNSE and UNS Gas, Inc. rate case proceedings.

INTRODUCTION

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

A. My Name is Robert B. Mease. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. Attachment I, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant ("CPA") and currently licensed in the state of West Virginia, as well as a Certified Rate of Return Analyst ("CRRA"). My years of work experience include serving as Vice President and Controller of Energy West, Inc. a public utility and energy company located in Great Falls, Montana. While with Energy West I had responsibility for all utility filings and participated in several rate case filings on behalf of the utility. As Energy West was a publicly traded company listed on the NASDAQ Exchange I also had responsibility for all filings with the Securities and Exchange Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present RUCO's recommendations for the establishment of a fair value rate of return.

Q. Is this your first case involving UNSE?

A. No. I participated in UNSE's most recent rate application filed for the test year ended December 31, 2012, and performed an analytical review of the Company's financial schedules that were included in their rate application.[1]

Q. Can you please briefly describe UNSE and its ownership structure and customer base?

A. UNS Electric is a wholly-owned subsidiary of UniSource Energy Services, a holding company owned by UNS Energy Corporation. In August of 2014 UNS Energy Corporation was purchased by Fortis, Inc. ("Fortis"). Fortis is an investor owned utility based in St. John's, Newfoundland and Labrador, Canada. UNSE's customer base is comprised of approximately 95,000 customers of which 87.00 percent are residential, approximately 12.00 percent commercial and the remaining 1.00 percent industrial

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[1] See Docket No. E-04204A-12-0504; Decision No. 74235

Q. Has UNSE elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. UNSE elected to perform a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to UNSE's FVRB.

Q. Please explain your role in RUCO's analysis of UNSE's Application.

A. I reviewed UNSE's Application and performed a cost of capital analysis to determine both an original cost rate of return ("OCROR") and a fair value rate of return ("FVROR") on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended cost of common equity and my recommended cost of debt. The recommendations contained in this testimony are based on information obtained from UNSE's Application, responses to data requests, and from market-based research that I conducted during my analysis.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am recommending that the Commission adopt an 8.35 percent cost of common equity. This 8.35 percent figure is the result obtained from my cost of equity analysis.

Cost of Debt – RUCO is recommending that the Commission adopt the Company's end of test year cost of long-term debt of 4.66 percent. This compares favorably to the Company's previous rate application where the cost of long-term debt was approved at 5.47 percent.

Capital Structure – I am recommending that the Commission adopt UNSE's actual end of test year capital structure comprised of 52.83 percent common equity and 47.17 percent long-term debt. The Company has no short-term debt.

Original Cost Rate of Return – I am recommending that the ACC adopt a 6.86 percent weighted average cost of capital as the original cost rate of return ("OCROR") for UNSE. This 6.86 percent figure is the weighted cost of RUCO's recommended costs of common equity and debt, and is 127 basis points lower than the 8.13 percent weighted average cost of capital being proposed by the Company.

Fair Value Rate of Return – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 5.26 percent which is my recommended 6.61 percent OCROR minus an inflation adjustment of 1.35 percent.

Q Why do you believe that RUCO's recommended 6.86 percent OCROR and 5.26 percent FVROR are appropriate rates of return for UNSE to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for UNSE meet the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). These two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk. It should be noted that neither case guarantees a rate of return on a utility investment, the cases provide a utility with an opportunity to earn an appropriate return.

RUCO's COST OF EQUITY FINDINGS

Q. What is your final recommended cost of equity capital for UNSE?

A. I am recommending a cost of equity of 8.35 percent. My recommended 8.35 percent cost of equity figure is the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

Discounted Cash Flow (DCF) Method

Q. Is the DCF model an acceptable methodology used in ratemaking for public utilities?

A. Yes. Basically the DCF model, is one of the oldest and most utilized models in determining the cost of equity in many utility hearings. In a 2014 rate case filing by Potomac Electric Power, in Washington, D.C., the commission relied primarily on a DCF analysis to arrive at the authorized ROE, "finding that he DCF method produces results more reasonable than those of other calculation methods."[2]

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[2] See EEI Report, page 29

Q. You stated that the commission "primarily" relied on the DCF model, should this model be relied upon exclusively in determining a utilities ROE?

A. No. While the DCF model is the most widely used and accepted model, including Arizona, it should be supplemented with additional models or calculations (i.e. CAPM model, risk assessment, comparable earnings assessment etc.) to add support to the final cost of equity analysis. The various models will produce different results depending on the economic conditions and inputs included in calculating the results. It is important to look at these alternative calculations to determine the reasonableness of the individual and overall final results.

Q. Please explain the DCF method that you used to estimate the Company's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model. This model is frequently referred to as the Gordon model. This DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that is used to determine the Company's cost of equity capital.

Q. In determining the rate of future dividend growth for the Company, what assumptions did you make?

A. There are two basic assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group comprised of fourteen publicly traded electric service providers.

Q. Why would you use a proxy group methodology as opposed to a direct analysis of the Company?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although UNSE's ultimate parent company, Fortis, Inc., is publicly-traded on the Toronto, Canadian Stock Exchange, UNSE is not. Because of this situation, I used a proxy group that includes fourteen electric utilities with similar risk characteristics as UNSE in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. The U.S. Supreme Court ruled in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944) decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy methodology used by most cost of equity analysts derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. Are these the same fourteen electric providers included in the proxy used by UNSE's cost of equity witness?

A. Yes. The Company's that are included in my analysis are the same electricity providers included in Ms. Ann Bulkley, the Company's cost of capital witness. However I did include one additional Company that being El Paso Electric. I added the additional Company to basically have a representative sample from all regions within the U.S. Each of the fourteen electric utilities included in our respective samples are tracked in the Value Line Investment Survey's ("Value Line") Electric Utility industry segment. Value Line follows electric utilities on a regional basis and issues quarterly updates on electric utilities located in the eastern, central and western portions of the U.S. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment B of my testimony contains Value Line's most recent evaluation on each of the companies that I included in the electric proxy group that I used for my cost of common equity analysis.

Capital Asset Pricing Model (CAPM) Method

Q. Can you please describe the CAPM and the benefits of preparing this analysis?

A. The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk. The relationship is specified by the Security Market Line (SLM) that indicates the relationship between each security or portfolio's "beta" and its resulting return. Beta is an indicator of investment risk. It is a measure of the expected amount of change in a security's variability of return relative to the return variability of the overall capital market. The general form of the CAPM is:

$$K = R_f + \beta\,(R_m - R_f)$$

Where: K = *cost of equity*

R_f = *risk free rate*

R_m = *return on market*

β = *beta*

$R_m - R_f$ = *market risk premium*

Q. Can you please identify the strengths of using the CAPM model in your analysis?

A. The strengths of the CAPM are as follows: (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it's highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept; and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What do you use for the risk-free rate?

A. The risk-free rate is generally recognized by use of U.S. Treasury securities in CAPM applications. Two general types of U.S. Treasury securities are most often used as the risk free *(Rf)* component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I performed my CAPM calculations using the three-month average yield (July thru September 2015) for 30-year U.S. Treasury bonds. The yields on long-term Treasury bonds are used since this matches the long-term perspective of the cost of equity analyses. Over this three-month period, these bonds had an average yield of 3.01 percent.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. Investors would like to believe that U.S. Treasury securities pose no threat of default no matter what their maturity dates are as they are backed by the United States Government. However, even when using Treasury instruments those with longer maturity dates do have slightly higher yields. When an investor locks up funds in long-term T-Bonds, the investor must be compensated for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). This compensation translates into higher rates of returns to the investor.

Q. What betas do you employ in your CAPM?

A. Once again, beta[3] is a measure of the relative volatility, or risk, of a particular stock in relation to the overall market. Betas less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. The most recent Value Line betas have been used in my analysis for each company in my proxy group.

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[3] See Attachment B – Individual proxy companies beta's identified

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule RBM-6, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 6.59 percent. My calculation using an arithmetic mean results in an average expected return of 7.19 percent and the results of using a geometric mean is 6.00 percent. The results obtained from my CAPM analysis exceed the current 4.60 percent yield on by 107 to 228 basis points.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.95%
CAPM	6.00% - 7.19%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 6.00 percent to 8.95 percent. My final recommended cost of common equity is 8.35 percent and is slightly higher than the average of the DCF and CAPM calculations. I did not take into account the geometric mean in my calculation of cost of equity. See RBM-3 for calculations.

Q. Can you provide a comparison of the results derived from Ms. Bulkley's models and yours?

	Company Witness	RUCO
DCF – Constant Growth	9.04% – 10.35%	8.95 %
DCF – Multi-Stage	9.30% -- 9.92%	
CAPM	9.59% -- 11.10%	6.00% -- 7.19%
Risk Premium	9.70% -- 10.72%	

UNSE's PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed UNSE's testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony of the Company's cost of equity expert witness, Ms. Ann Bulkley.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 10.35 percent which is 200 basis points higher than my recommended 8.35 percent cost of equity.

Q. Can you explain the primary differences behind the 200 basis point spread between the Company's ROE and the RUCO's calculations?

A. Yes I will. The primary difference is reflected in Ms. Bulkley's use of forward looking estimates **only** as opposed to the use of both historical and forward looking estimates. As she states in her testimony "The required ROE should be forward looking estimate; therefore, the analyses supporting my recommendation should rely on forward looking inputs and assumptions (e.g., projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high valuations of utility stocks and market's expectations for higher interest rates."[4]

Q. Do you concur with Ms. Bulkley's assessment and her use of only forward looking inputs only?

A. No I don't and neither does the Arizona Corporation Commissioners. Decision No. 75265, issued on September 8, 2015, states the following, "EPCOR is also critical of RUCO's use of historical data in evaluating cost of equity, which the Company claims should be a forward-looking analysis. However, we believe that consideration of both historical and projected data is appropriate in evaluating cost of equity."[5]

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[4] See Ms. Bulkley's testimony, page 7

[5] See EPCOR Water Arizona, Inc., Decision No. 75268

Q. Are there other reasons that you can identify that have created the 200 basis point differential?

A. Yes. There are several other reasons that we ROE's are substantially different.

(1) As Ms. Bulkley explained in her testimony she utilized a Risk Premium methodology that took into account UNS Electric's utility operations and compared in size to the proxy group of companies. While she did calculate a size premium she went on to say in her testimony that "While I have estimated the small size effect, I am not proposing a specific adjustment for this factor. Rather, I have considered the small size of UNS Electric in my assessment of business risks in order to determine where, within a reasonable range of returns, UNS Electric's required ROE falls."[6]

(2) Included in the Company's testimony is a calculation described as Bond Yield Plus Risk Premium Analysis. As described in Ms. Bulkley's testimony "this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated to bear that risk."

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[6] See Ms. Bulkley's testimony, page 46

(3) Ms. Bulkley's also states that "the returns at the low end of the DCF range do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of the Company. Because of this concern, I have not considered the low end of the range of DCF results in developing my ROE recommendation."[7]

Q. As a follow up to Ms. Bulkley's response to the previous question and her comments related to risk premium for small companies, has the ACC addressed this in previous decisions?

A. Yes. In Decision No. 75268, the Commission made the following findings; "Although a company's size may sometimes be considered as a business risk factor, for utilities of substantial size, (those having access to capital markets) it is a minimal consideration in determining business risk. Small utilities (e.g., non-class A utilities) may have substantial risk due to the inability to hire employees or contract for sufficient levels of expertise (management, technical & financial) to perform effectively and efficiently. Small utilities also have other risks such as information access, greater annual variability in operating expenses, and greater regulatory risk both due to lack of skilled rate case personnel and the percentage of operating expenses and rate base components reviewed by Staff and intervenors. Due to the latter two reasons, for any adopted return on equity the

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[7] See Ms. Bulkley's testimony, page 6

distribution of actual returns is greater for small utility than for a large utility, and greater variability means greater risk. However, most of the proxy companies used in the cost of capital analyses, including EPCOR, are a conglomeration of many smaller water systems and have the capacity to attract the appropriate level of talent for proficient operation. Thus, the business risk of the EPCOR systems parallels that that of the sample companies, and **we do not believe a cost of equity adjustment for size is appropriate."**

Q. What methods did the Company witness, Ms. Bulkley, use to arrive at her cost of common equity for UNSE?

A. Ms. Bulkley used the constant growth DCF model and a multi-stage DCF. In addition, she also employed both the CAPM and risk premium methods to estimate UNSE's final cost of common equity. I did not employ the risk premium methodology because this Commission has traditionally placed more weight on the results of the DCF and CAPM.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 10.35 percent cost of equity capital proposed by the Company is 200 basis points higher than the 8.35 percent cost of equity capital that I am recommending.

CURRENT ECONOMIC ENVIRONMENT

Current Economics Surrounding the Electric Utilities

Q. Does it appear that investor-owned electricity companies, as well as the utility sector in general, performed well in 2014?

A. Yes. In reviewing Edison Electric Institute's (EEI) 2014 Financial Review as published in their Annual Report of the U.S. Investor-Owned Electric Utility Industry, the electric companies are performing very well.

Q. **Can you please describe the EEI organization, and how that organization serves the electric utility industry?**

A. Yes. EEI's mission is to ensure member's success by advocating public policy, expanding market opportunities, and proving strategic business information. EEI is an association that represents <u>all</u> U.S. investor-owned electric companies. Their members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and employ more than 500,000 workers. The proxy companies that we chose in our analysis are all members of EEI. UNSE is also a member of EEI. In addition, EEI has seventy international companies as Affiliate Members and 250 industry suppliers and related organizations as Associate Members.

Q. Can you please describe the purpose of the 2014 Financial Review as discussed in the prelude to Edison Electric Institute's annual report?

A. The 2014 Financial Review is a source for critical financial data covering 48 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges and also includes data on six additional companies that provide regulated electric service but are not listed on U.S. stock exchanges.

Q. Briefly identify the 2014 financial highlights as presented in the Presidents Letter included in the 2014 Financial Review.

A.

> "In 2014, the EEI Index returned an average of 28.9 percent, compared to the 10.0 percent return posted by the Dow Jones Industrial Average and the S&P 500's 13.7 percent return. For 10 years ending December 31, 2014, The EEI Index's 156 percent return outpaced the Dow Jones Industrial's 114 percent return and S&P's 110 percent return."
>
> "The industry's average credit rating improved to BBB+ form BBB, the first change since 2004 when it increased from BBB-, as individual company ratings were overwhelmingly positive in 2014."
>
> "The industry's dividend yield at the end of 2014 stood at 3.3 percent, and 38 utilities, or 79 percent of the industry, increased their dividend yield last year, the largest percentage on record."

Q. Did EEI publish information on rate case applications that member companies have been involved in for year 2014?

A. Yes. Investor-owned electric utilities filed 58 rate cases in 2014. The average requested ROE was the lowest requested in their history and the awarded ROE was the lowest in their data reaching back to 1990.

Q. Has there been updates published by EEI for rate case activity related to investor-owned members for year 2015?

A. Yes. The Rate Case Summary report issued by EEI for the second quarter of 2015 stated that the average awarded ROE continued to be at record lows and consistent with the downward trend extending over more three decades.

Q In the EEI 2014 annual report was there any mention of the purchase of UNS by Fortis?

A. Yes. "UNS said joining Fortis enhances the financial strength of its local utility operations, and provides additional support for long-term investment."

Q. Did the Company comment on the acquisition by Fortis, Inc. and the affects on its long-term investment?

A. Yes. Mr. Hutchens, in his testimony states "I also would like to point out that the average cost of debt used in the Company revenue requirement of 4.66 percent is 22% lower than the cost of debt approved in the last rate case. This reduction in the Company's debt costs resulted from constructive regulatory outcomes, steady improvements in UNS Electric's financial condition, a strong credit rating and favorable capital market conditions. UNS Electric's increase to an A3 rating after being acquired by Fortis Inc. puts the Company in position to access the capital markets on favorable terms, which will help to reduce the amount of future borrowing costs that need to be recovered from customers.

General Economic Conditions

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Has the Fed's quantitative easing actions resulted in lower yields on long-term Treasury instruments?

A. Yes. Despite a recent rise in the yields of longer-term instruments (Attachment C), mainly due to uncertainty over when the Fed will reverse its policy of quantitative easing, the yields on various treasury and utility instruments are currently at historic lows.

Q. Can you please explain how general economic and financial conditions are considered in the determination of the cost of capital for a public utility?

A. Yes. The cost of capital is determined in part by the current and future economic and financial conditions. The level of economic activity; the stage of the business cycle; the trend in interest rates, and the level of inflation or expansion all play an important factor in determining the cost of capital. While there are other factors involved these are the most important and at any point in time each can have an influence on the cost of capital.

Q. Can you describe the recent trends in economic conditions and their impact on capital costs over the past thirty years?

A. Yes. Since the early 1980's through the end of 2007 the United States economy had been relatively stable. This period had been characterized by longer economic expansions, small contractions, low and/or declining inflation, and declining interest rates and other capital costs. However, in 2008 and 2009, the economy declined as a result of the mortgage crisis and had a negative effect on the financial markets both in the US and international financial markets. This decline was described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Since 2008, the U.S. and other governments implemented unprecedented actions to attempt to correct or minimize the scope and effects of this worldwide recession.

The recession bottomed out in mid-2009 and the economy began to slowly expand again, initially at a slow rate but has escalated at a much quicker rate. This is evidenced by the unemployment rate reducing from 6.7 at the end of 2013 to 5.6 percent at the end of December, 2014. Arizona's unemployment rate hasn't recovered quite as well as the national average and at the end of December, 2014 was 6.8 percent. The length of this most recent recession and the slow recovery indicate that the impact may be felt for an extended period of time.

Q. Can you please describe how the economic and financial indicators were examined and how they relate generally to the cost of capital?

A. Schedule RBM-7 identifies relevant economic data such Gross Domestic Product ("GDP"), Industrial Production Growth, Unemployment, Consumer Price Index ("CPI") and Producer Price Index. These schedules also show that 2007 was sixth year of economic expansion and the economy entered into a significant decline as indicated in the GDP negative expansion for year 2008 and the increase in unemployment rates. Since 2010, the economy began to rebound, however, overall economic growth continues to be slower than the initial period of prior expansions.

Since 2008, the CPI has been 3 percent or lower, with 2014 being only 1.1 percent. The annual rate of inflation has generally been declining over the past several business cycles and continues as evidenced by 2014 annual inflation rate of 1.7 percent and the projected 2015 rate which appears to be less that year 2014. The current levels of inflation are at the lowest levels over the past 35 years and are indicative of lower capital costs.

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Schedule RBM-6 shows that interest rates rose sharply to record levels in 1975-1981, when the inflation rate was high and generally rising. Interest rates declined substantially as did inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and for the years 2009 through 2014, interest rates have been the lowest since prior to 1975. Since 2008, the Federal Reserve has lowered the Federal Funds rate in 2012 and 2013 both U.S. and corporate bond yields declined to their lowest levels in more than 35 years. Interest rates have risen slightly from those lows since the beginning of 2013. Even with the recent increases, both government and corporate lending rates remain at historically low levels through 2014, and have continued through year 2015.

Q. What do the economic indicators show for trends of common share prices?

A. Schedule RBM-7 show that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. Beginning in 1983 a significant upward trend in stock prices began. However, the beginning of the recent financial crisis saw stock prices decline significantly and stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices have recovered substantially and have ultimately reached and exceeded the levels achieved prior to the beginning of the "crash" and the DOW Jones Industrial average has reached all-time highs.

Q. What conclusions can be reached from your discussion of economic and financial conditions?

A. The most recent downturn in the economy has resulted in a decline in the investor expectation of returns. This is evident in several ways: 1) lower interest rates on bank deposits; 2) lower interest rates on U.S. Treasury and corporate bonds; and, 3) lower increases in Social Security cost of living benefits. While unemployment has reduced substantially, the average median income of families has reduced as well. Finally, as noted above, utility bond interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest levels in the past 35 years. While the economy is recovering from this latest recession, it is recovering slower than expected. Slower recovery means that the results of the traditional cost of equity models are lower than prior to the recession. This is evidenced and supported by the EEI 2014 Financial Report identifying the rate case activity during 2014 and that authorized rates of return on equity are the lowest since 1990.

Q. What is the current outlook for the economy?

A. Information published by the FOMC indicates that economic activity has been expanding at a moderate pace during 2015, household spending has been increasing, the housing sector has improved and that business fixed investment has also been increasing. However, inflation has continued to run below the Committee's long-run objective, partly reflecting declines in energy pricing and non-energy imports. The unemployment rate is held steady with slight improvements during 2015. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor markets continuing to improve. Inflation is expected to remain near its recent low level in the near term but expects inflation to rise gradually toward the 2 percent over the medium term. When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-term goals of maximum employment and inflation of 2 percent. It is anticipated that, even after employment and inflation are near consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels that is considered normal.

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery. During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties.

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on October 30, 2015, the seasonally adjusted unemployment rate for Arizona has increased from 6 percent in April, 2015, to 6.3 percent in September, 2015. This compare the national unemployment rate of 5.1 percent for the period ending in September, 2015. I believe it is safe to say that Arizona's economy is recovering at a much slower pace that the national average.

COST OF DEBT AND CAPITAL STRUCTURE

Q. What cost of long-term debt are you recommending for UNSE?

A. I am recommending that the Commission adopt UNSE's actual end of test year cost of long-term debt of 4.66 percent.

Q. Please describe the Company-proposed capital structure.

A. The Company is proposing an adjusted end of test year capital structure comprised of no short-term debt, 47.17 percent long-term debt and 52.83 percent common equity.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure, Schedule RBM-2, is virtually identical to the average capital structure of the electric companies included in my sample.

Q. What capital structure are you recommending for UNSE?

A. I am recommending that the Commission adopt the Company's actual end of test year capital structure comprised of zero short-term debt, 47.17 percent long-term debt and 52.83 percent long-term common equity, which is essentially the same as the capital structure being proposed by UNSE.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for UNSE?

A. Based on my recommended capital structure, comprised of 47.17 percent long-term debt and 52.53 percent common equity, I am recommending an original cost weighted average cost of capital of 6.61 percent, Schedule RBM-1. This is the weighted average cost of my recommended cost of long-term debt of 4.66 percent and my recommended 8.35 percent cost of common equity.

Q. What fair value rate of return are you recommending for UNSE?

A. I am recommending a FVROR of 5.26 percent, RBM-1, which is 166 basis points lower than my OCROR of 6.61 percent. My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as UNSE.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because UNSE elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, UNSE performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Ms. Bulkley or any other witness for UNSE constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNSE?

A. Yes, it does.

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE #	
RBM - 1	WEIGHTED AVERAGE COST OF CAPITAL
RBM - 2	COST OF LONG TERM DEBT
RBM - 3	COST OF COMMON EQUITY
RBM - 4	INFLATION ADJUSTMENT
RBM - 5	DCF COST OF EQUITY CAPITAL
RBM - 6	CAPM COST OF EQUITY CAPITAL
RBM - 7	ECONOMIC INDICATORS

ATTACHMENTS	
B	VALUE LINE REPORTS
C	YAHOO FINANCE ANALYSTS REPORTS / STOCK PRICES
D	ECONOMIC INDICATORS REPORTS

Schedule RBM-1

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	Long - Term Debt	$ 169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
2	Short - Term Debt	-	-	-	-	-	-
3	Common Equity	189,932	-	189,932	52.83%	8.35%	4.41%
4	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		6.61%
5	Inflation Adjustment						0.25%
6	**ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL**						6.86%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (B): TESTIMONY RBM
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINE 1 ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1; SCHEDULE RBM-2
COLUMN (E): LINE 3 - SCHEDULE RBM-3
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E) COST	(F) WEIGHTED COST
7	LONG-TERM DEBT	$ 169,590	$ -	$ 169,590	47.17%	3.31%	1.56%
8	COMMON EQUITY	189,932	-	189,932	52.83%	7.00%	3.70%
9	TOTAL CAPITALIZATION	$ 359,522	$ -	$ 359,522	100.00%		5.26%

10 COLUMN (A) THROUGH (D) SEE ABOVE

11 COLUMN (E), LINE 7 SEE RBM-2

Schedule RBM-2

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

COST OF LONG TERM and SHORT TERM DEBT (thousands of US dollars)

		End of Test Year (Actual)			End of Test Year (Proposed)		
LINE NO.	LONG TERM DEBT DESCRIPTION	(A) Actual as of DEC. 31, 2014	(B) Annual Interest	(C) Annual Cost Rate Long Term Debt	(D) Proposed as of DEC. 31, 2014	(E) Annual Interest	(F) RUCO ADJUSTED BALANCE
	Fixed Rate Debt:						
1	6.50% Senior Unsecured Notes due 08/15	$ 50,000	$ 3,250	6.50%	$ -	$ -	$ -
2	7.10% Senior Unsecured Notes Series B due 08/23	50,000	3,550	7.10%	50,000	3,550	7.10%
3	3.22% Senior Unsecured Notes Series A due 08/27	-	-	-	80,000	2,576	3.22%
4	3.95% Senior Unsecured Notes Series B due 04/45	-	-	-	50,000	1,975	3.95%
5	Total Fixed Rate Debt	100,000	6,800	6.80%	180,000	8,101	4.50%
6	**Variable Rate Debt:**						
7	4 Year Term Loan due 08/15	30,000	629	2.10%	-	-	-
8	Total Variable Rate Debt	30,000	629	2.10%	-	-	-
9	**Total Long-Term Debt (Ln 5 + Ln 8)**	$ 130,000	$ 7,429	5.71%	$ 180,000	$ 8,101	4.50%
10	**Unamortized Debt Discount, Premium**						
11	Expense and Loss on Reacquired Debt	(410)	-		(1,246)		
12	**Amortization of Debt Discount and**						
13	Expense and Loss on Reacquired Debt	-	182		-	169	
14	**Credit Facility Commitment Fee**	-	51		-	63	
15	**Total Long Term Debt - Net of expenses (Ln 9 less Ln 11, 13, 14)**	129,590	7,662		178,754	$ 8,333	
16	**Total Cost Long Term Debt (Col. B / Col. A) (Col. E / Col. F)**			5.91%			4.66%
	SHORT TERM DEBT						
17	Revolving Line of Credit	$ 40,000	$ 513	1.28%	$ -	$ -	$ -
18	Total Debt Actual - End of Test Year	$ 169,590	$ 8,175	4.82%			
19	Total Debt Proposed - End of Test Year				$ 178,754	$ 8,333	4.66%
20	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT						-1.35%
21	COST OF LONG-TERM DEBT - FAIR VALUE (LINE 19 - LINE 20)						3.31%

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE RBM-3

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	DCF METHODOLOGY		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.95%	SCHEDULE RBM-4
3	CAPM METHODOLOGY		
4	CAPM - GEOMETRIC MEAN ESTIMATE	6.00%	SCHEDULE RBM-6, PAGE 1 OF 2
5	CAPM - ARITHMETIC MEAN ESTIMATE	7.19%	SCHEDULE RBM-6, PAGE 2 OF 2
6	AVERAGE OF DCF AND CAPM ARITHEMETIC ESTIMATES	6.59%	(LINE 4 + LINE 5) / 2
7	PREMLINIARY COST OF COMMON EQUITY ESTIMATE	8.07%	TESTIMONY, RBM
8	FINAL ADJUSTMENT	0.28%	TESTIMONY, RBM
9	FINAL COST OF COMMON EQUITY	8.35%	
10	LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT	-1.35%	SCHEDULE RBM-4
11	COST OF COMMON EQUITY ESTIMATE - FAIR VALUE	7.00%	LINE 8 - LINE 9

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDULE RBM-4

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2009	1.66%	3.26%	1.61%
2	2010	1.15%	3.22%	2.06%
3	2011	0.55%	2.78%	2.23%
4	2012	0.42%	1.78%	1.36%
5	2013	0.80%	2.10%	1.30%
6	2014	0.49%	1.10%	0.61%
7	2015	0.54%	1.02%	0.48%
8				
9	**RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT - AVERAGE COLUMN (D)**			1.35%

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 7
COLUMN (D), LINE 11: TESTIMONY - RBM

-

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

DCF 90 DAY CONSTANT GROWTH

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02	/	48.28	=	4.18%	4.28%	4.00%	5.50%	4.75%	8.27%	9.03%	9.80%
2	AEP	American Electric Power Company	$ 2.12	/	55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30	/	72.04	=	4.58%	4.67%	3.50%	4.04%	3.77%	8.16%	8.44%	8.71%
4	EE	EL Paso Electric	$ 1.18	/	35.62	=	3.31%	3.41%	5.00%	7.00%	6.00%	8.40%	9.41%	10.43%
5	EDE	Empire District Electric Company	$ 1.04	/	22.11	=	4.70%	4.79%	3.00%	4.00%	3.50%	7.77%	8.29%	8.80%
6	ES	Eversource Energy	$ 1.67	/	47.84	=	3.49%	3.60%	6.50%	5.80%	6.15%	9.39%	9.75%	10.10%
7	GXP	Great Plains Energy Inc.	$ 0.98	/	25.42	=	3.86%	3.97%	6.00%	6.37%	6.19%	9.97%	10.16%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88	/	60.13	=	3.13%	3.20%	6.00%	4.00%	5.00%	7.19%	8.20%	9.22%
9	OTTR	Otter Tail Corporation	$ 1.23	/	26.28	=	4.69%	4.78%	1.50%	6.00%	3.75%	6.22%	8.53%	10.83%
10	PNW	Pinnacle West Capital Corporation	$ 2.38	/	60.93	=	3.91%	3.99%	3.50%	5.37%	4.44%	7.47%	8.43%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80	/	25.85	=	3.09%	3.24%	10.00%	8.60%	9.30%	11.83%	12.54%	13.25%
12	POR	Portland General Electric Company	$ 1.20	/	34.97	=	3.43%	3.51%	5.50%	3.92%	4.71%	7.42%	8.22%	9.03%
13	SO	Southern Company	$ 2.17	/	43.63	=	4.97%	5.06%	3.00%	3.58%	3.29%	8.05%	8.35%	8.64%
14	WR	Westar Energy, Inc.	$ 1.44	/	36.66	=	3.93%	3.99%	3.00%	3.40%	3.20%	6.99%	7.19%	7.39%
		AVERAGE					**3.94%**	**4.03%**	**4.68%**	**5.16%**	**4.92%**	**8.26%**	**8.95%**	**9.63%**

AVERAGE OF LOW, MEAN AND HIGH 8.95%

REFERENCES:
COLUMN (A); Annualized Dividends per Value Line
COLUMN (B): AVERAGE STOCK PRICES, SEE TESTIMONY ATTACHMENT « (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1+.05 COLUMN (G))
COLUMN (G) AVERAGE COLUMN (E) AND (F)

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

SCHEDULE RBM-6
PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

								(A)									(B)
LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+	[	ß	x	(	r_m	-	r_f	)	]	=	EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	3.01%	+	[	0.80	x	(	10.10%	-	6.10%	)	]	=	6.21%
2	AEP	American Electric Power Company, Inc.	k	=	3.01%	+	[	0.70	x	(	10.10%	-	6.10%	)	]	=	5.81%
3	DUK	Duke Energy Corporation	k	=	3.01%	+	[	0.60	x	(	10.10%	-	6.10%	)	]	=	5.41%
4	EE	EL Paso Electric	k	=	3.01%	+	[	0.75	x	(	10.10%	-	6.10%	)	]	=	6.01%
5	EDE	Empire District Electric Company	k	=	3.01%	+	[	0.70	x	(	10.10%	-	6.10%	)	]	=	5.81%
6	ES	Eversource Energy	k	=	3.01%	+	[	0.75	x	(	10.10%	-	6.10%	)	]	=	6.01%
7	GXP	Great Plains Energy Inc.	k	=	3.01%	+	[	0.85	x	(	10.10%	-	6.10%	)	]	=	6.41%
8	IDA	IDACORP, Inc.	k	=	3.01%	+	[	0.80	x	(	10.10%	-	6.10%	)	]	=	6.21%
9	OTTR	Otter Tail Corporation	k	=	3.01%	+	[	0.85	x	(	10.10%	-	6.10%	)	]	=	6.41%
10	PNW	Pinnacle West Capital Corporation	k	=	3.01%	+	[	0.70	x	(	10.10%	-	6.10%	)	]	=	5.81%
11	PNM	PNM Resources, Inc.	k	=	3.01%	+	[	0.85	x	(	10.10%	-	6.10%	)	]	=	6.41%
12	POR	Portland General Electric Company	k	=	3.01%	+	[	0.80	x	(	10.10%	-	6.10%	)	]	=	6.21%
13	SO	Southern Company	k	=	3.01%	+	[	0.55	x	(	10.10%	-	6.10%	)	]	=	5.21%
14	WR	Westar Energy, Inc.	k	=	3.01%	+	[	0.75	x	(	10.10%	-	6.10%	)	]	=	6.01%
15	**AVERAGE**							**0.75**									**6.00%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

UNS Electric, Inc.
Test Year Ended December 31, 2014
CAPM COST OF EQUITY CAPITAL

SCHEDULE RBM-6
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

							(A)							(B)
LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	ß	x (	r_m	-	r_f	)]	=	EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	3.01%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	7.49%
2	AEP	American Electric Power Company, Inc.	k	=	3.01%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.93%
3	DUK	Duke Energy Corporation	k	=	3.01%	+ [	0.60	x (	12.00%	-	6.40%	)]	=	6.37%
4	EE	EL Paso Electric	k	=	3.01%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	7.21%
5	EDE	Empire District Electric Company	k	=	3.01%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.93%
6	ES	Eversource Energy	k	=	3.01%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	7.21%
7	GXP	Great Plains Energy Inc.	k	=	3.01%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.77%
8	IDA	IDACORP, Inc.	k	=	3.01%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	7.49%
9	OTTR	Otter Tail Corporation	k	=	3.01%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.77%
10	PNW	Pinnacle West Capital Corporation	k	=	3.01%	+ [	0.70	x (	12.00%	-	6.40%	)]	=	6.93%
11	PNM	PNM Resources, Inc.	k	=	3.01%	+ [	0.85	x (	12.00%	-	6.40%	)]	=	7.77%
12	POR	Portland General Electric Company	k	=	3.01%	+ [	0.80	x (	12.00%	-	6.40%	)]	=	7.49%
13	SO	Southern Company	k	=	3.01%	+ [	0.55	x (	12.00%	-	6.40%	)]	=	6.09%
14	WR	Westar Energy, Inc.	k	=	3.01%	+ [	0.75	x (	12.00%	-	6.40%	)]	=	7.21%
15	**AVERAGE**						**0.75**							**7.19%**

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ß (r_m - r_f)]$$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

UNS Electric, Inc.
Test Year Ended December 31, 2014
Docket No. E-04204A-15-0142

SCHEDUL E RBM-7

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	2011	3.00%	1.70%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.93%	5.06%	5.58%
23	2012	1.70%	2.20%	3.25%	0.75%	0.00% - 0.25%	0.08%	2.92%	3.99%	4.42%
24	2013	1.10%	2.40%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.24%	4.19%	4.60%
25	2014	1.25%	2.65%	3.25%	7.50%	0.00% - 0.25%	6.00%	3.90%	4.25%	4.65%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY

COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

ATTACHMENT A

ATTACHMENT A

ROBERT B. MEASE, CPA, CRRA
Education and Professional Qualifications

EDUCATION

Bachelors Degree Business Administration / Accounting - Morris Harvey College.

Attended West Virginia School of Graduate Studies and studied Accounting and Public Administration

Attended numerous courses and seminars for Continuing Professional Educational purposes.

WORK EXPERIENCE

Controller
Knives of Alaska, Inc., Diamond Blade, LLC, and Alaska Expedition Company.

Financial Manager / CFO
All Saints Camp & Conference Center

Energy West, Inc.
Vice President, Controller

- Led team that succeeded in obtaining a $1.5 million annual utility rate increase
- Coached accountants for proper communication techniques with Public Service Commission, supervised 9 professional accountants
- Developed financial models used to negotiate an $18 million credit line
- Responsible for monthly, quarterly and annual financial statements for internal and external purposes, SEC filings on a quarterly and annual basis, quarterly presentations to Board of Directors and shareholders during annual meetings, coordinated annual audit
- Communication with senior management team, supervised accounting staff and resolved all accounting issues, reviewed expenditures related to capital projects
- Monitored natural gas prices and worked with senior buyers to ensure optimal price obtained

Junkermier, Clark, Campanella, Stevens
Consulting Staff

- Established a consulting practice that generated approximately $160k the first year of existence
- Prepared business plan and projections for inclusion in clients financing documents
- Prepared written reports related to consulting engagements performed
- Developed models used in financing documents and made available for other personnel to use
- Performed Profit Enhancement engagements
- Participated during audit of large manufacturing client for two reporting years

Prior to 1999, held various positions: TMC Sales, Inc. as **Vice President / Controller**, with American Agri-Technology Corporation as **Vice President / CFO** and with Union Carbide Corporation as **Accounting Manager. (Union Carbide was a multi-national Fortune 500 Company that was purchased by Dow Chemical)**

PROFESSIONAL AFFILIATIONS

Past Member - Institute of Management Accountants
Member - American Institute of CPA's
Member – Society of Utility and Regulatory Financial Analysts
Past Member –WV Society of CPA's and Montana Society of CPA's

RESUME OF RATE CASE AND REGULATORY PARTICIPATION WITH RUCO

Utility Company	Docket No.
Arizona Water Company (Eastern Group)	W-01445A-11-0310
Pima Utility Company	W-02199A-11-0329 et al.
Tucson Electric Power Company	E-01933A-12-0291
Arizona Water Company (Northern Group)	W-01445A-12-0348
UNS Electric	E-04204A-12-0504
Global Water	W-01212A-12-0309 et al.
LPSCO	SW-01428A-13-0042 et al.
Johnson Utilities	WS-02987A-13-0477
Johnson Utilities	WS-02987A-08-0180
APS	E-01345A-11-0224
EPCOR Water Arizona, Inc.	WS-01303A-09-0343
Utility Source, LLC	WS-04235A-13-0331
EPCOR Water Arizona, Inc.	WS-01303A-14-0010
EPCOR Water, Purchase of Willow Valley Water, Co.	W-01732A-15-0131

ATTACHMENT B

ALLETE NYSE-ALE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
47.32	14.1	15.7 16.0	0.81	4.4%

VALUE LINE

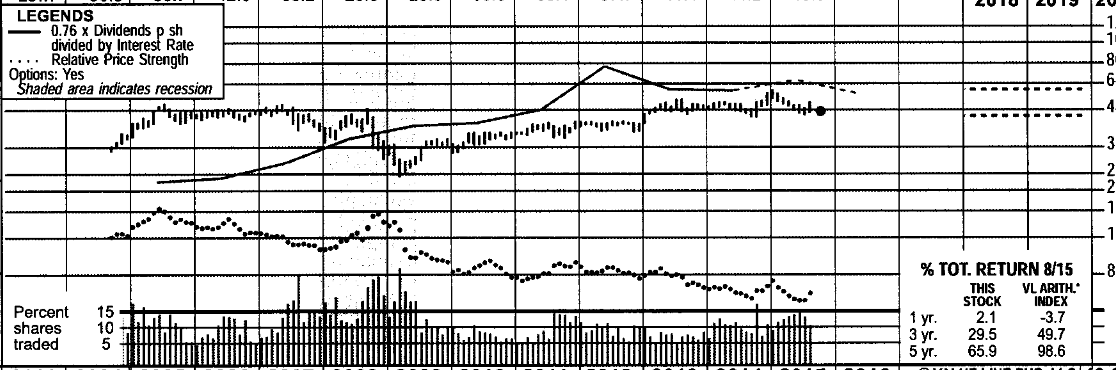
TIMELINESS 3 Raised 4/24/15

SAFETY 2 New 10/1/04

TECHNICAL 3 Raised 9/18/15

BETA .80 (1.00 = Market)

High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.1	-3.7
3 yr.	29.5	49.7
5 yr.	65.9	98.6

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	*10%*
Low	45	(-5%)	*4%*

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	1	0	0	0
to Sell	0	0	1	0	1	2	1	1	1

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	97	117	117
to Sell	90	77	79
Hld's(000)	32344	33487	35643

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	*27.75*	*29.05*	**Revenues per sh**	*34.00*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	*6.30*	*6.40*	**"Cash Flow" per sh**	*7.75*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	*3.30*	*3.20*	**Earnings per sh A**	*4.00*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	*2.02*	*2.10*	**Div'd Decl'd per sh B ■ †**	*2.40*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	*5.70*	*4.75*	**Cap'l Spending per sh**	*5.50*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	*37.30*	*38.45*	**Book Value per sh C**	*42.50*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	*49.00*	*49.25*	**Common Shs Outst'g D**	*50.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	*Bold figures are Value Line estimates*		**Avg Ann'l P/E Ratio**	*13.5*
--	--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91			**Relative P/E Ratio**	*.85*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%			**Avg Ann'l Div'd Yield**	*4.5%*
					737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	*1360*	*1430*		**Revenues ($mill)**	*1700*
					68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	*160*	*155*		**Net Profit ($mill)**	*195*
					28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	*17.0%*	*14.0%*		**Income Tax Rate**	*14.0%*
					.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	*3.0%*	*2.0%*		**AFUDC % to Net Profit**	*2.0%*
					39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	*44.0%*	*43.0%*		**Long-Term Debt Ratio**	*41.5%*
					60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	*56.0%*	*57.0%*		**Common Equity Ratio**	*58.5%*
					990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	*3250*	*3315*		**Total Capital ($mill)**	*3625*
					860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	*3675*	*3750*		**Net Plant ($mill)**	*4075*
					8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	*6.0%*	*5.5%*		**Return on Total Cap'l**	*6.5%*
					11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*8.5%*	*8.0%*		**Return on Shr. Equity**	*9.0%*
					11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*8.5%*	*8.0%*		**Return on Com Equity E**	*9.0%*
					5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	*3.5%*	*2.5%*		**Retained to Com Eq**	*3.5%*
					54%	57%	51%	61%	93%	81%	66%	71%	72%	67%	*61%*	*67%*		**All Div'ds to Net Prof**	*61%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $1390.4 mill. **Due in 5 Yrs** $281.9 mill.
LT Debt $1272.4 mill. **LT Interest** $57.3 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $13.4 mill.

Pension Assets-12/14 $544.2 mill.
Oblig. $714.5 mill.

Pfd Stock None

Common Stock 48,850,462 shs.

MARKET CAP: $2.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+1.1	-1.1	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.24	5.45	6.09
Capacity at Peak (Mw)	1790	1793	1985
Peak Load, Winter (Mw) F	1633	1646	1637
Annual Load Factor (%)	79.0	NA	NA
% Change Customers (avg.)	+.5	NA	NA
Fixed Charge Cov. (%)	341	306	345

ANNUAL RATES of change (per sh)	**Past** 10 Yrs.	**Past** 5 Yrs.	**Est'd '12-'14** to '18-'20
Revenues	-.5%	--	*5.5%*
"Cash Flow"	6.0%	5.5%	*6.5%*
Earnings	7.0%	1.0%	*6.5%*
Dividends	NMF	2.0%	*4.0%*
Book Value	4.5%	5.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	*355*	*361.7*	*1360*
2016	*350*	*345*	*365*	*370*	*1430*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	.85	.46	*.97*	*1.02*	*3.30*
2016	*.90*	*.45*	*.90*	*.95*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505		

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 56%; wind, 7%; other, 3%; purchased, 34%. Fuel costs: 31% of revs. '14 deprec. rate: 2.9%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

A development fee from a transaction will bolster ALLETE's earnings in the second half of 2015. ALLETE Clean Energy is building a wind facility that it will sell to a utility in North Dakota. The development fee from the transaction will amount to $20 million-$25 million (pretax) in the last two quarters of 2015. This will amount to $0.25-$0.30 a share, which we will *include* in our earnings presentation. As a result of this deal, ALLETE raised its earnings guidance for 2015 from $3.00-$3.20 a share to $3.20-$3.40 a share. We have raised our estimate by $0.25 a share, to $3.30. However . . .

Minnesota Power's taconite customers have lowered their production plans — and thus, their power needs. (Taconite is used in steelmaking.) These customers expect to need power for just 80% of capacity in September and 90% of capacity in the fourth quarter. This is the first time since the last recession that the taconite producers have been running well below 100%. This is why ALLETE raised its earnings target by just $0.20 a share, despite a transaction that is expected to add more than that to the bottom line. The utility will make up part of the demand shortfall by selling power on the wholesale market and trimming operating expenses, but these moves won't be enough to make up the difference.

We have trimmed our 2016 earnings estimate by a nickel a share. This is in response to the demand cutbacks by the taconite customers. More will be known at the start of December, when they announce their demand expectations for the first four months of 2016.

Minnesota Power has a major project that is on track for completion in May, and construction of another significant project is expected to begin later in 2016. The former is a $260 million upgrade to a coal-fired unit. The latter is a $345 million investment in a transmission line from northern Minnesota to the Canadian border. The utility benefits from current cost recovery for these kinds of capital spending.

ALLETE stock has a dividend yield that is a cut above average and 3- to 5-year total return potential that is just average, by utility standards.

Paul E. Debbas, CFA *September 18, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: $7.78/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
54.08	15.6	15.1 13.0	0.89	4.1%	VALUE LINE

TIMELINESS 3 Lowered 6/12/15

SAFETY 2 Raised 9/19/14

TECHNICAL 2 Raised 9/18/15

BETA .70 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+30%)	*10%*
Low	50	(-10%)	*3%*

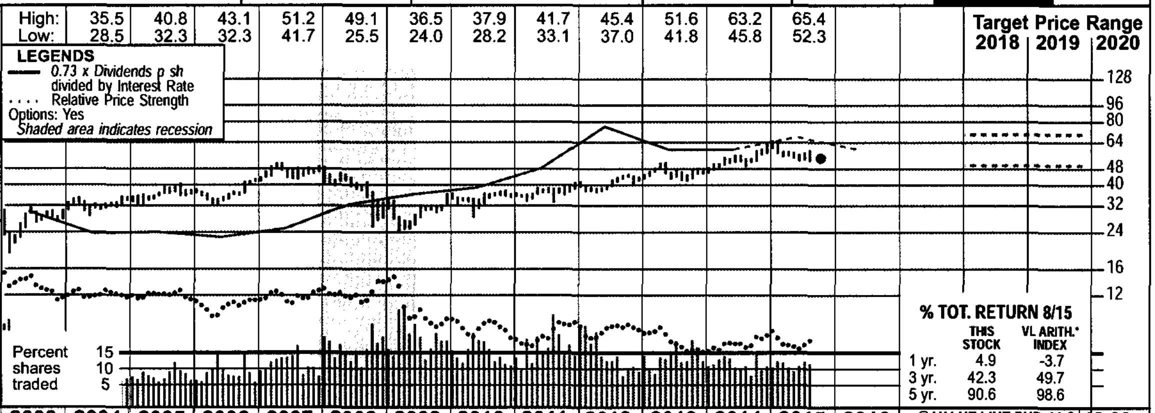
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	10	0
to Sell	0	0	0	0	1	0	0	4	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	361	338	327
to Sell	308	368	336
Hld's(000)	326985	324222	328262

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4
Low:	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.9	-3.7
3 yr.	42.3	49.7
5 yr.	90.6	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	**34.35**	**35.10**	Revenues per sh	**39.50**
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	**7.75**	**8.00**	"Cash Flow" per sh	**9.25**
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	**3.60**	**3.65**	Earnings per sh A	**4.25**
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	**2.15**	**2.27**	Div'd Decl'd per sh B ■	**2.65**
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	**9.75**	**8.05**	Cap'l Spending per sh	**8.50**
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	**35.85**	**37.30**	Book Value per sh C	**42.00**
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	**492.00**	**494.00**	Common Shs Outst'g D	**500.00**
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	**14.0**
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84			Relative P/E Ratio	**.90**
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%			Avg Ann'l Div'd Yield	**4.5%**
						12111	12622	13380	14440	13489	14427	15116	14945	15357	17020	**17000**	**17350**	Revenues ($mill)	**19800**
						1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	**1675**	**1715**	Net Profit ($mill)	**2020**
						29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	**36.0%**	**36.0%**	Income Tax Rate	**36.0%**
						5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	**10.0%**	**8.0%**	AFUDC % to Net Profit	**8.0%**
						54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	**50.0%**	**49.5%**	Long-Term Debt Ratio	**49.5%**
						44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	**50.0%**	**50.5%**	Common Equity Ratio	**50.5%**
						20222	21902	24342	26290	28958	29184	29747	30823	32913	33001	**35325**	**36575**	Total Capital ($mill)	**41400**
						24284	26781	29870	32987	34344	35674	36971	38763	40997	44117	**46850**	**48475**	Net Plant ($mill)	**54100**
						6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
						11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	**9.5%**	**9.5%**	Return on Shr. Equity	**9.5%**
						11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	**10.0%**	**10.0%**	Return on Com Equity E	**10.0%**
						5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	**4.0%**	**3.5%**	Retained to Com Eq	**4.0%**
						54%	53%	55%	55%	56%	66%	60%	63%	62%	61%	**63%**	**65%**	All Div'ds to Net Prof	**66%**

CAPITAL STRUCTURE as of 6/30/15
Total Debt $20683 mill. **Due in 5 Yrs** $9375 mill.
LT Debt $17761 mill. **LT Interest** $799 mill.
Incl. $2114 mill. securitized bonds. Incl. $552 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $293 mill.
Pension Assets-12/14 $4968 mill. **Oblig.** $5225 mill.

Pfd Stock None

Common Stock 490,559,618 shs. **as of 7/23/15**
MARKET CAP: $27 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.1	-1.5	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.3
Fixed Charge Cov. (%)	280	326	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.5%	- -	*3.5%*
"Cash Flow"	1.5%	1.5%	*4.5%*
Earnings	1.5%	1.5%	*5.0%*
Dividends	.5%	4.0%	*5.0%*
Book Value	4.5%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4708	3942	**4400**	**3950**	**17000**
2016	**4550**	**4150**	**4500**	**4150**	**17350**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.39	3.34
2015	1.29	.88	**1.03**	**.40**	**3.60**
2016	**1.15**	**.85**	**1.20**	**.45**	**3.65**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53		

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.3 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 36% of revenues. '14 reported deprec. rates (utility): 1.4%-8.6%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is waiting for the Ohio regulators to rule on the company's request for a purchased-power agreement between its nonregulated generating assets and its utilities in the state. In recent years, AEP has been moving away from nonregulated operations toward regulated businesses. A purchased-power agreement would be another step in this direction. Due to low capacity prices, the nonregulated business has declined in recent years (more below), although recent changes in the rules for the power markets ought to improve conditions somewhat. AEP isn't necessarily going to retain its nonregulated generating assets—a sale or spinoff is under consideration. There is no timetable for a decision from the commission or the company.

The company received a rate increase in Kentucky and filed a rate application in Oklahoma. Kentucky Power's tariffs were raised by $45.4 million, based on a 10.25% return on equity. Public Service of Oklahoma is seeking a hike of $172 million, based on a 10.5% ROE. New tariffs should take effect at the start of 2016.

We have raised our 2015 earnings estimate by $0.10 a share, to $3.60. Second-quarter profits were better than we expected. Management lifted its earnings guidance from $3.40-$3.60 to $3.50-$3.65. AEP's regulated operations are benefiting from rate relief and increased transmission investment. (In fact, AEP raised its 2015 capital budget for transmission by $200 million.) This is offsetting weakness in the nonregulated sector. Lower capacity payments will hurt comparisons by $0.35 a share this year, mostly in the second half.

We look for just a slight profit increase in 2016. A further decline from the nonregulated side will probably offset most of the improvement that is likely from the regulated activities.

A dividend increase is likely in the fourth quarter. We estimate that the board of directors will boost the quarterly dividend by $0.03 a share (5.7%). AEP is targeting a payout ratio of 60%-70%.

Investors should stay tuned to see what happens with the nonregulated operations. For now, the dividend yield and 3- to 5-year total return potential are near the norms for the utility industry.

Paul E. Debbas, CFA *September 18, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢. '14 EPS don't add due to rounding. Next egs. report due late Oct. **(B)** Div'ds historically paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '14: $17.67/sh. **(D)** In mill. **(E)** Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earned on avg. com. eq., '14: 9.9%. Regul. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

DUKE ENERGY NYSE-DUK

RECENT PRICE	75.29	P/E RATIO	16.5 (Trailing: 18.7 Median: NMF)	RELATIVE P/E RATIO	0.91	DIV'D YLD	4.4%	VALUE LINE

TIMELINESS 4 Lowered 8/14/15

SAFETY 2 New 6/1/07

TECHNICAL 4 Raised 8/21/15

BETA .60 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+25%)	*10%*
Low	70	(-5%)	*3%*

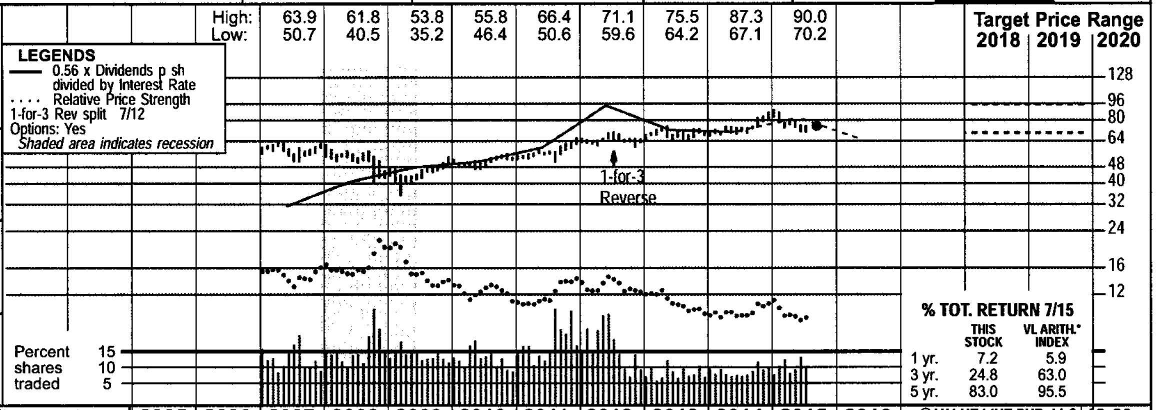
Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	9	0	0	0
to Sell	0	0	4	0	0	3	0	0	5

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	431	469	472
to Sell	423	460	494
Hld's(000)	392694	390171	391310

	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	70.2



% TOT. RETURN 7/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.2	5.9
3 yr.	24.8	63.0
5 yr.	83.0	95.5

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE). Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. In July of 2012, Duke acquired Progress Energy and effected a 1-for-3 reverse split. Data for the "old" Duke are not shown because they are not comparable.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	*35.40*	*36.95*	Revenues per sh	*41.75*
--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	*9.75*	*10.20*	"Cash Flow" per sh	*11.25*
--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	*4.45*	*4.80*	Earnings per sh A	*5.25*
--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	*3.24*	*3.36*	Div'd Decl'd per sh B ■	*3.80*
--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	*11.05*	*11.85*	Cap'l Spending per sh	*11.75*
--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	*58.50*	*59.90*	Book Value per sh C	*64.25*
--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	*688.00*	*689.00*	Common Shs Outst'g D	*692.00*
--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	*16.0*
--	--	.85	1.04	.89	.81	.87	1.11	.98	.95			Relative P/E Ratio	*1.00*
--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%			Avg Ann'l Div'd Yield	*4.5%*
--	10607	12720	13207	12731	14272	14529	19624	24598	23925	*24350*	*25450*	Revenues ($mill)	*28750*
--	1080.0	1522.0	1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	*3090*	*3325*	Net Profit ($mill)	*3735*
--	29.4%	31.9%	32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	*32.5%*	*32.5%*	Income Tax Rate	*32.5%*
--	6.9%	7.2%	16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
--	41.0%	30.9%	38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	*49.0%*	*50.0%*	Long-Term Debt Ratio	*52.5%*
--	59.0%	69.1%	61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	*51.0%*	*50.0%*	Common Equity Ratio	*47.5%*
--	44220	30697	34238	37863	40457	41451	77307	79482	78088	*78825*	*81350*	Total Capital ($mill)	*93700*
--	41447	31110	34036	37950	40344	42661	68558	69490	70046	*75300*	*79750*	Net Plant ($mill)	*92500*
--	3.1%	6.0%	4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.5%*
--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	*7.5%*	*8.0%*	Return on Com Equity E	*8.5%*
--	4.1%	2.0%	.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	*2.0%*	*2.5%*	Retained to Com Eq	*2.5%*
--	--	72%	89%	84%	73%	72%	82%	78%	76%	*73%*	*70%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $41331 mill. **Due in 5 Yrs** $16418 mill.
LT Debt $36795 mill. **LT Interest** $1685 mill.
Incl. $1428 mill. capitalized leases. Incl. $1265 mill. nonrecourse LT debt of variable interest entities.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $205 mill.
Pension Assets-12/14 $8498 mill.
Oblig. $7966 mill.
Pfd Stock None
Common Stock 688,330,456 shs.
as of 8/4/15
MARKET CAP: $52 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.8	+1.3	+2.2
Avg. Indust. Use (MWH)	2675	2687	2876
Avg. Indust. Revs. per KWH (¢)	5.84	5.89	6.15
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.8	+.8	+1.0
Fixed Charge Cov. (%)	263	327	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	--	1.5%	*4.5%*
"Cash Flow"	--	1.0%	*5.5%*
Earnings	--	3.5%	*5.0%*
Dividends	--	2.5%	*3.5%*
Book Value	--	3.0%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3630	3577	6722	5695	19624
2013	5898	5879	6709	6112	24598
2014	6263	5708	6395	5559	23925
2015	6065	5589	*6850*	*5846*	*24350*
2016	*6350*	*5900*	*7150*	*6050*	*25450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.86	.99	1.01	.59	3.71
2013	.89	.74	1.40	.94	3.98
2014	1.05	1.02	1.25	.81	4.13
2015	1.09	.87	*1.60*	*.89*	*4.45*
2016	*1.20*	*.95*	*1.70*	*.95*	*4.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.735	.735	.75	.75	2.97
2012	.75	.75	.765	.765	3.03
2013	.765	.765	.78	.78	3.09
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.1 mill. elec. customers in North Carolina, Florida, Indiana, South Carolina, Ohio, & Kentucky, and over 500,000 gas customers in Ohio & Kentucky. Owns independent power plants & has international ops. Acq'd Cinergy 4/06; spun off midstream gas ops. 1/07; acq'd Progress Energy 7/12. Elec. rev. breakdown: residential, 44%; commercial, 30%; industrial, 15%; other, 11%. Generating sources: coal, 37%; nuclear, 28%; gas, 21%; other, 1%; purchased, 13%. Fuel costs: 35% of revs. '14 reported deprec. rates: 2.4%-3.3%. Has 28,300 empls. Chairman: Ann Gray. Pres. & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Web: www.duke-energy.com.

Duke Energy has stepped up its dividend growth rate. In recent years, the board of directors has been boosting the annual dividend by $0.06 a share. The latest increase, payable in September, doubled this rate. The latest increase was 3.8%.

The company completed a significant asset acquisition. Duke paid $1.25 billion for another utility's 700-megawatt stake in nuclear and coal-fired assets in North Carolina that Duke operates and already co-owned. The purchase should add $0.04 to share net in 2015 and $0.07-$0.08 annually starting in 2016. However . . .

We have lowered our 2015 share-earnings estimate by $0.05 a share. Second-quarter profits fell a bit short of our estimate. Also, results from Duke's operations in Brazil continue to disappoint due to the weak economy and unfavorable weather conditions. Our estimate is a bit below the company's guidance of $4.55-$4.75 a share because we include certain things, such as costs associated with the Progress Energy takeover (which Duke is still incurring, even three years later), that management excludes. On the other hand, we raised our 2016 share-net estimate by a nickel.

Duke has several significant investments pending, and more proposals are coming. It helps having sound finances. The utility is adding 650 mw of gas-fired capacity in South Carolina at a cost of $600 million. Duke plans to construct a 1,685-mw gas-fired facility in Florida at a cost of $1.5 billion. The company has announced a $1.1 billion system modernization project in the western Carolinas. It has a $1.8 billion-$2.0 billion (40%) stake in a proposed gas pipeline in the Carolinas and has taken a $225 million (7.5%) stake in another proposed pipeline to serve Florida. All of these investments should contribute to the company's profit growth in the coming years. Finally, Duke plans to resubmit a system modernization plan in Indiana after a previous $1.9 billion proposal was rejected.

This stock is untimely, but might interest income-oriented accounts. The dividend yield and 3- to 5-year total return potential are somewhat above average for a utility.

Paul E. Debbas, CFA *August 21, 2015*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; gains (loss) on disc. ops.: '12, 6¢; '13, 2¢; '14, (80¢); '15, 5¢. '12 & '13 EPS don't add due to chng. in shs. or rounding.

Next egs. report due early Nov. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '14: $38.94/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC/SC: 10.2%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earned on avg. com. eq., '14: 7.0%. Reg. Climate: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	80

EL PASO ELECTRIC NYSE-EE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
35.19	18.0 (Trailing: 15.7 Median: 15.0)	0.96	3.4%

TIMELINESS 4 Lowered 7/10/15

SAFETY 2 Raised 5/11/07

TECHNICAL 3 Lowered 7/31/15

BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3
Low:	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8

Target Price Range
2018 | 2019 | 2020

2018-20 PROJECTIONS

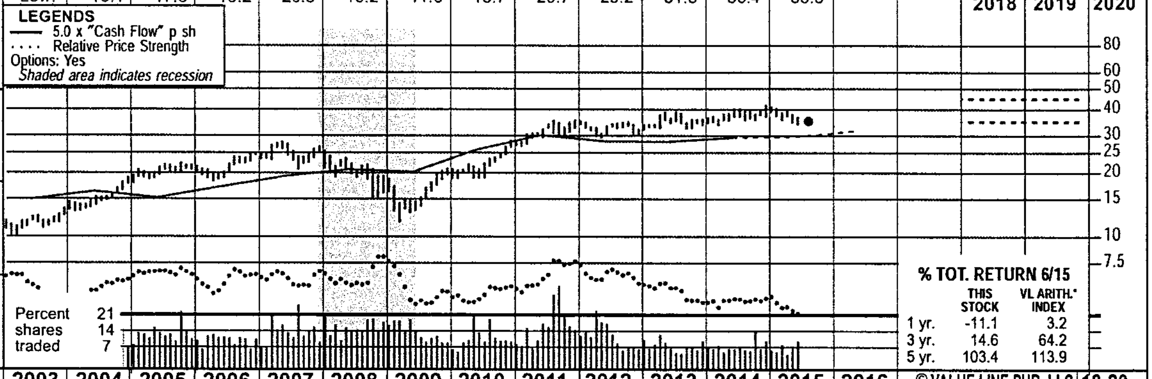
	Price	Gain	Ann'l Total Return
High	45	(+30%)	*10%*
Low	35	(Nil)	*4%*

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	69	87	88
to Sell	76	72	74
Hld's(000)	40115	39006	38975



% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.1	3.2
3 yr.	14.6	64.2
5 yr.	103.4	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	*21.00*	*22.15*	**Revenues per sh**	*26.75*
2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	*5.95*	*6.35*	**"Cash Flow" per sh**	*7.75*
.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	*1.95*	*2.20*	**Earnings per sh A**	*2.75*
--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	*1.17*	*1.23*	**Div'd Decl'd per sh B**	*1.40*
1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	*7.90*	*7.75*	**Cap'l Spending per sh**	*7.25*
7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	*25.10*	*26.00*	**Book Value per sh C**	*29.50*
57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	*40.50*	*40.65*	**Common Shs Outst'g D**	*41.10*
9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	*Bold figures are Value Line estimates*		**Avg Ann'l P/E Ratio**	*14.5*
.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86			**Relative P/E Ratio**	*.90*
--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%			**Avg Ann'l Div'd Yield**	*3.5%*
						803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	*850*	*900*	**Revenues ($mill)**	*1100*
						36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	*80.0*	*90.0*	**Net Profit ($mill)**	*115*
						33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	*33.0%*	*33.0%*	**Income Tax Rate**	*33.0%*
						15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	*25.0%*	*22.0%*	**AFUDC % to Net Profit**	*13.0%*
						52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	*56.0%*	*56.0%*	**Long-Term Debt Ratio**	*56.5%*
						47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	*44.0%*	*44.0%*	**Common Equity Ratio**	*43.5%*
						1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	*2300*	*2415*	**Total Capital ($mill)**	*2800*
						1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	*2645*	*2790*	**Net Plant ($mill)**	*3050*
						4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	*5.0%*	*5.5%*	**Return on Total Cap'l**	*6.0%*
						6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	*8.0%*	*8.5%*	**Return on Shr. Equity**	*9.5%*
						6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	*8.0%*	*8.5%*	**Return on Com Equity E**	*9.5%*
						6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	*3.0%*	*4.0%*	**Retained to Com Eq**	*4.5%*
						--	--	--	--	--	--	26%	43%	47%	49%	*59%*	*55%*	**All Div'ds to Net Prof**	*50%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1207.6 mill. **Due in 5 Yrs** $156.6 mill.
LT Debt $1134.2 mill. **LT Interest** $68.2 mill.
(LT interest earned: 2.6x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/14 $272.9 mill.
Oblig. $341.1 mill.

Pfd Stock None

Common Stock 40,392,332 shs.
as of 4/30/15

MARKET CAP: $1.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.7	+.4	-1.6
Avg. Indust. Use (MWH)	21659	21908	21505
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1765	1852	1879
Peak Load, Summer (Mw)	1688	1750	1766
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.3	+1.3
Fixed Charge Cov. (%)	302	280	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	4.5%	1.5%	*3.5%*
"Cash Flow"	6.5%	7.5%	*5.0%*
Earnings	13.5%	6.5%	*3.5%*
Dividends	--	--	*5.0%*
Book Value	8.5%	8.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.7	*225*	*286.3*	*175*	*850*
2016	*175*	*240*	*300*	*185*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	*.61*	*1.15*	*.10*	*1.95*
2016	*.15*	*.70*	*1.20*	*.15*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	--	.22	.22	.22	.66
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295			

BUSINESS: El Paso Electric Company (EPE) provides electric service to 400,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 35%; coal, 5%; purchased, 13%. Fuel costs: 34% of revenues. '14 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. CEO: Thomas V. Shockley, III. President: Mary Kipp. Inc.: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has filed a general rate case in New Mexico. The utility is seeking a rate increase of $8.6 million (7.1%), based on a return of 9.95% on a common-equity ratio of 49.29%. Since EPE's last rate case in the state, which took effect at the start of 2010, the company has added nearly $1.3 billion of rate base, including the first two units (88 megawatts each) of a four-unit gas-fired generating station. New tariffs are expected to take effect early in the second quarter of 2016.

As this report was going to press, the utility was planning to put forth a rate application in Texas shortly. The amount it will request was unknown. As in New Mexico, new rates are expected to go into effect by the early second period of 2016.

Regulatory lag will affect the company's earnings this year and next. EPE is incurring costs (such as depreciation) associated with the two new generating units mentioned above, but these facilities are not reflected in the utility's rates. Accordingly, profits will almost certainly decline materially this year. The company's share-earnings guidance for 2015 is $1.75-$2.15, which includes $0.31-$0.37 of regulatory lag. Assuming reasonable rate treatment and less regulatory lag in 2016, earnings will likely make a partial recovery.

The last two units of the aforementioned project are expected to begin operating in 2016. One should come on line in the first half of the year, the other in the second half. The total cost is estimated at $374 million. EPE will file rate cases in New Mexico and Texas to place these two units in the rate base.

As we had expected, the board of directors raised the dividend in the second quarter. The increase was $0.06 a share (5.4%) annually. EPE expects to hike the disbursement at a rate of 4%-6% annually over the next several years. The company's modest payout ratio gives the board plenty of room to boost the dividend.

The untimely stock's dividend yield is below average for a utility. Although we project solid dividend growth through 2018-2020, total return potential is just a bit above average for this industry.

Paul E. Debbas, CFA *July 31, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due early Aug. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '14: $112.1 mill., $2.78/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '14: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	80
Earnings Predictability	85

EMPIRE DISTRICT NYSE-EDE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
21.13	16.3	16.3 16.0	0.93	5.0%	VALUE LINE

TIMELINESS 4 Raised 8/28/15
SAFETY 2 Raised 3/23/12
TECHNICAL 3 Raised 9/11/15
BETA .70 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+40%)	13%
Low	20	(-5%)	4%

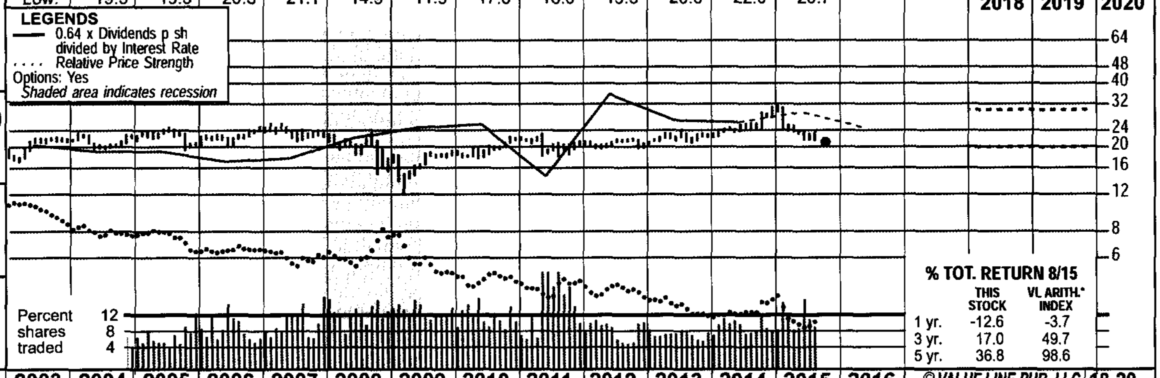
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	1	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	63	70	65
to Sell	63	65	65
Hld's(000)	21381	20494	20421

High:	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5
Low:	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	20.7



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.6	-3.7
3 yr.	17.0	49.7
5 yr.	36.8	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	*13.65*	*14.00*	Revenues per sh	*16.00*
2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	*3.45*	*3.55*	"Cash Flow" per sh	*4.25*
1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	*1.30*	*1.45*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	*1.05*	*1.07*	Div'd Decl'd per sh B ■ †	*1.20*
4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	*4.20*	*2.55*	Cap'l Spending per sh	*3.50*
13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	*18.20*	*18.70*	Book Value per sh C	*20.25*
17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	*44.00*	*46.00*	Common Shs Outst'g D	*47.50*
21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.85			Relative P/E Ratio	*.85*
5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%			Avg Ann'l Div'd Yield	*5.0%*
						386.2	413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	*600*	*645*	Revenues ($mill)	*765*
						23.8	39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	*55.0*	*65.0*	Net Profit ($mill)	*85.0*
						33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	*37.5%*	*38.0%*	Income Tax Rate	*37.5%*
						2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	*10.0%*	*3.0%*	AFUDC % to Net Profit	*6.0%*
						51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
						49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	*49.0%*	*48.0%*	Common Equity Ratio	*50.0%*
						803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	*1640*	*1800*	Total Capital ($mill)	*1925*
						896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	*2000*	*2020*	Net Plant ($mill)	*2125*
						4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
						6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
						6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	*7.0%*	*7.5%*	Return on Com Equity E	*9.0%*
						NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	*1.5%*	*2.0%*	Retained to Com Eq	*3.0%*
						NMF	90%	117%	109%	109%	110%	49%	76%	68%	66%	*80%*	*74%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $900.4 mill. **Due in 5 Yrs** $213.6 mill.
LT Debt $803.1 mill. **LT Interest** $41.7 mill.
Incl. $3.7 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $192.7 mill.
Oblig. $251.9 mill.

Pfd Stock None

Common Stock 43,723,355 shs.
as of 7/31/15

MARKET CAP: $925 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.2	+1.3	+1.3
Avg. Industrial Use (MWH)	2913	2943	2981
Avg. Industrial Rev/KWH (¢)	7.66	7.93	8.21
Capacity at Peak (Mw)	1391	1377	1326
Peak Load, Summer (Mw)	1142	1080	1162
Annual Load Factor (%)	52.2	56.2	52.8
% Change Customers (avg.)	+.6	+.5	+.3
Fixed Charge Cov. (%)	314	331	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	3.0%	3.0%	*5.0%*
Earnings	2.5%	5.0%	*3.0%*
Dividends	-2.5%	-4.5%	*3.0%*
Book Value	1.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	137.2	131.6	159.2	129.1	557.1
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	164.5	134.5	*160*	*141*	*600*
2016	*180*	*145*	*170*	*150*	*645*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.25	.60	.23	1.32
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.34	.15	*.56*	*.25*	*1.30*
2016	*.34*	*.25*	*.59*	*.27*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	- -	- -	.64
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26	.26	.26		

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 45%; commercial, 32%; industrial, 16%; other, 7%. Generating sources: coal, 47%; gas, 27%; hydro, 1%; purch., 25%. Fuel costs: 37% of revenues. '14 reported depr. rate: 3.0%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric received an electric rate increase in Missouri. The state regulators approved a settlement calling for a $17.1 million (3.9%) rate hike. This was a "black box" agreement in which an allowed return on equity was not specified. The increase enabled Empire District Electric to place an environmental upgrade to a coal-fired plant in the rate base. Additionally, the utility will now be able to recover a portion of any changes in transmission costs through its fuel adjustment clause. New tariffs took effect on July 26th.

The utility plans to file another electric rate case in Missouri in the fourth quarter of 2015. Empire District Electric will need to place a 100-megawatt plant expansion in the rate base. This project is expected to be completed in the first half of 2016 at a cost of $165 million-$175 million. New tariffs will take effect in late 2016.

Regulatory lag will continue to affect Empire District Electric's earnings through 2016. Because the aforementioned environmental upgrade was completed in late 2014, but wasn't recovered in rates until July of this year, earnings declined in the first half of 2015. The lag in recovering the plant expansion will also hold back earnings next year. We have cut our 2015 profit estimate by $0.10 a share because June-quarter results fell short of our estimate. Our revised estimate is at the low end of the company's targeted range of $1.30-$1.45 a share. We are sticking with our 2016 forecast of $1.45 a share.

We look for a dividend increase in the fourth quarter. We think the board of directors will boost the annual disbursement by two cents a share (1.9%), the same increase as in each of the past two years.

This untimely stock has been one of the poorest performers among electric utilities so far in 2015. Year to date, the price is down about 30%, but is still within our 2018-2020 Target Price Range. We think this underperformance is mainly due to a lessening of takeover speculation. The dividend yield and 3- to 5-year total return potential are above average, by utility standards.

Paul E. Debbas, CFA *September 18, 2015*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '12 EPS don't add due to rounding. Next earnings report due late Oct. **(B)** Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. **(C)** Incl. intangibles. In '14: $5.93/sh. **(D)** In mill. **(E)** Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '15: none specified; earned on avg. com. eq., '14: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	85

EVERSOURCE ENERGY NYSE-ES

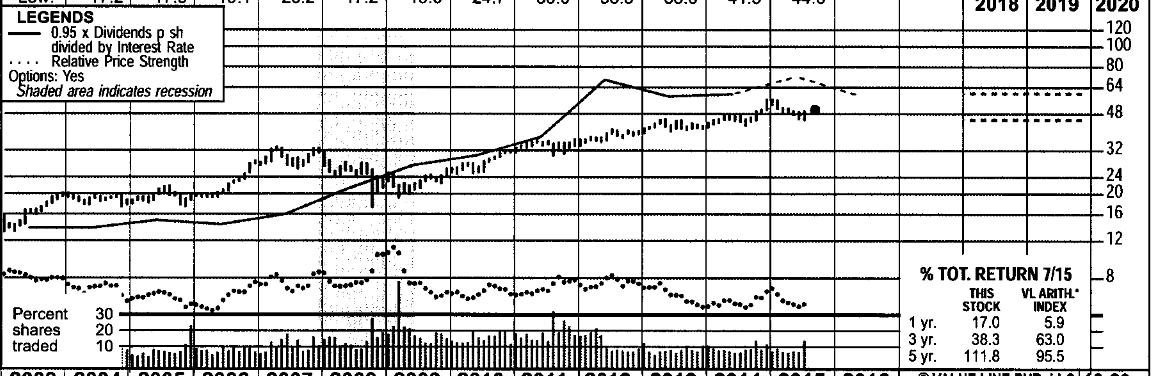
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
50.41	17.1	(Trailing: 17.5 Median: 17.0)	0.94	3.5%

VALUE LINE

TIMELINESS 3 Lowered 8/14/15
SAFETY 1 Raised 5/22/15
TECHNICAL 4 Lowered 8/7/15
BETA .75 (1.00 = Market)

High:	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8
Low:	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6

LEGENDS
— 0.95 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	2	0	1

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	200	233	203
to Sell	213	211	255
Hld's(000)	215261	223425	223824

% TOT. RETURN 7/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.0	5.9
3 yr.	38.3	63.0
5 yr.	111.8	95.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	*25.95*	*26.20*	Revenues per sh	*28.00*
5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	*5.30*	*5.60*	"Cash Flow" per sh	*7.00*
d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	*2.90*	*3.05*	Earnings per sh A	*3.75*
.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	*1.67*	*1.78*	Div'd Decl'd per sh B ■	*2.10*
2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	*5.80*	*6.65*	Cap'l Spending per sh	*6.25*
15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	*32.65*	*33.90*	Book Value per sh C	*38.25*
131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	*318.00*	*319.00*	Common Shs Outst'g D	*322.00*
--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.95	*Value Line*		Relative P/E Ratio	*.90*
.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*
						5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	*8250*	*8350*	Revenues ($mill)	*9050*
						128.5	126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	*935*	*990*	Net Profit ($mill)	*1220*
						30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
						17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
						63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	*46.0%*	*46.5%*	Long-Term Debt Ratio	*46.5%*
						35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	*53.0%*	*53.0%*	Common Equity Ratio	*53.0%*
						6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	18738	*19600*	*20400*	Total Capital ($mill)	*23200*
						6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	18647	*19900*	*21350*	Net Plant ($mill)	*25500*
						3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
						5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
						5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	*9.0%*	*9.0%*	Return on Com Equity E	*10.0%*
						1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
						72%	94%	50%	45%	50%	49%	50%	72%	59%	58%	*57%*	*58%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $9851.2 mill. **Due in 5 Yrs** $3813.7 mill.
LT Debt $8602.1 mill. **LT Interest** $372.5 mill.
(LT interest earned: 4.7x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/14 $4126.5 mill.
Oblig. $5486.2 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 317,647,540 shs.
as of 4/30/15
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+47.0	+1.0	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+59.8	NA	NA
Fixed Charge Cov. (%)	320	427	426

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-7.0%	-8.5%	*3.5%*
"Cash Flow"	-2.0%	-3.0%	*7.0%*
Earnings	8.0%	5.5%	*8.5%*
Dividends	9.5%	11.5%	*6.5%*
Book Value	5.5%	9.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1099	1628	1861	1684	6273.8
2013	1995	1635	1892	1777	7301.2
2014	2290	1677	1892	1881	7741.9
2015	2513	1817	*2000*	*1920*	*8250*
2016	*2500*	*1850*	*2050*	*1950*	*8350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.56	.15	.66	.55	1.89
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	.69	2.58
2015	.80	.65	*.80*	*.65*	*2.90*
2016	*.85*	*.65*	*.85*	*.70*	*3.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175	.4175			

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 million electric, 504,000 gas customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to three fourths of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts. Acquired NSTAR 4/12. Electric revenue breakdown: residential, 49%; commercial, 38%; industrial, 5%; other, 8%. Fuel costs: 39% of revenues. '14 reported deprec. rates: 2.7%-3.3%. Has 8,200 employees. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy should post solid earnings increases this year and next. The company is reducing operating and maintenance expenses as it attains further benefits from the merger with NSTAR in 2012. Rate relief is another factor. Electric rates in Connecticut were raised in late 2014, and a gas rate case is pending in Massachusetts (see below). Eversource's gas utilities are benefiting from customer conversions from oil heat to gas heat. And, despite a reduction in the allowed return on equity for transmission, the company's investment in this area is another source of growth. Our 2015 earnings estimate, which we raised by $0.05 a share after Eversource reported June-period results, is at the upper end of the company's guidance of $2.75-$2.90. The same factors that are lifting earnings this year should remain in place in 2016. Our profit forecast of $3.05 a share would produce a 5% increase over the estimated 2015 figure.

A gas rate case is pending in Massachusetts. Eversource is seeking a $23 million (5.5%) increase, based on a 10.25% return on a 52.94% common-equity ratio. A ruling from the state commission is expected in the fourth quarter, with new tariffs taking effect at the start of 2016.

Eversource is awaiting a commission ruling on a settlement in New Hampshire. If approved, the utility would sell its generating assets in the state. These have a book value of $650 million and are contributing $0.09-$0.10 to annual share net. It would recover its stranded costs through the issuance of securitized bonds. A decision is expected by yearend.

Two major projects would enhance the company's long-term growth. Eversource wants to build a $1.4 billion transmission line that would be connected to Québec. It hopes to begin construction in late 2016, with an in-service date in the first half of 2019. The company also has a 40% stake in a proposed $3 billion pipeline to increase the supply of gas to New England. The partners hope to have it in service in time for the winter of 2018-2019.

This stock has a dividend yield that is somewhat below the utility mean. Total return potential to 2018-2020 is unspectacular, despite good dividend growth prospects.

Paul E. Debbas, CFA *August 21, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '12 EPS don't add due to chng. in shs., '13 & '14 due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd chgs. In '14: $23.89/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: '11, 9.6%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earn. on avg. com. eq., '14: 8.4%. Regul. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
24.77	16.7	16.9 16.0	0.95	4.2%

VALUE LINE

TIMELINESS 5 Lowered 6/19/15
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Raised 9/11/15
BETA .85 (1.00 = Market)

High:	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3
Low:	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1

Target Price Range
2018 | 2019 | 2020

2018-20 PROJECTIONS

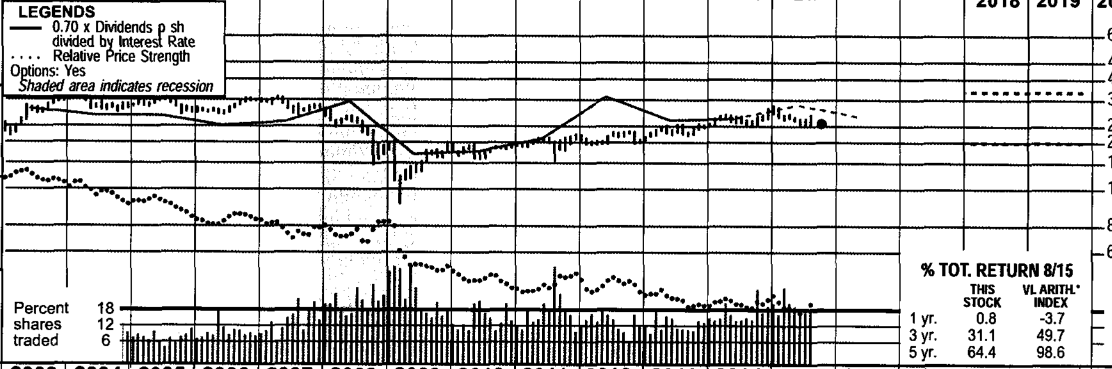
	Price	Gain	Ann'l Total Return
High	35	(+40%)	*12%*
Low	20	(-20%)	*Nil*

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	9	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	132	125	122
to Sell	125	148	125
Hld's(000)	119797	121848	130044



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.8	-3.7
3 yr.	31.1	49.7
5 yr.	64.4	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	*16.20*	*17.45*	Revenues per sh	*19.50*
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	*4.00*	*4.65*	"Cash Flow" per sh	*6.00*
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	*1.40*	*1.75*	Earnings per sh A	*2.00*
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	*1.00*	*1.06*	Div'd Decl'd per sh B ■	*1.20*
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	*5.25*	*3.90*	Cap'l Spending per sh	*3.75*
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	*23.65*	*24.35*	Book Value per sh C	*26.75*
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	*154.50*	*154.75*	Common Shs Outst'g D	*155.50*
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	*Value Line*		Relative P/E Ratio	*.85*
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	*2500*	*2700*	Revenues ($mill)	*3050*
						164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	*220*	*270*	Net Profit ($mill)	*320*
						18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	*33.0%*	*35.0%*	Income Tax Rate	*35.0%*
						2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	*9.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	*51.0%*	*47.5%*	Long-Term Debt Ratio	*48.0%*
						50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	*48.5%*	*52.0%*	Common Equity Ratio	*51.5%*
						2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	*7530*	*7260*	Total Capital ($mill)	*8075*
						2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	*8695*	*8850*	Net Plant ($mill)	*9025*
						8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	*4.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	*6.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
						13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	*6.0%*	*7.0%*	Return on Com Equity E	*7.5%*
						3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	*2.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						76%	104%	91%	NMF	81%	54%	66%	63%	55%	60%	*70%*	*61%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $4291.1 mill. **Due in 5 Yrs** $1961.8 mill.
LT Debt $3486.7 mill. **LT Interest** $180.2 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $14.2 mill.
Pension Assets-12/14 $730.0 mill.
Oblig. $1186.8 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,333,594 shs.
as of 8/3/15
MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.8	+.2	+.4
Avg. Indust. Use (MWH)	1443	1424	1455
Avg. Indust. Revs. per KWH (¢)	6.23	6.80	6.79
Capacity at Peak (Mw)	6719	NA	NA
Peak Load, Summer (Mw)	5653	NA	NA
Annual Load Factor (%)	49.6	NA	NA
% Change Customers (avg.)	+.2	+.7	+.9
Fixed Charge Cov. (%)	235	267	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-6.5%	-6.5%	*3.5%*
"Cash Flow"	-2.0%	1.5%	*8.0%*
Earnings	-4.0%	2.5%	*5.0%*
Dividends	-6.0%	-8.5%	*6.0%*
Book Value	4.5%	2.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	*800*	*541.9*	*2500*
2016	*600*	*650*	*850*	*600*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	.12	.28	*.90*	*.10*	*1.40*
2016	*.20*	*.40*	*1.00*	*.15*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245		

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 838,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 64%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 21%. Fuel costs: 29% of revs. '14 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's largest utility subsidiary has received a rate order in Missouri. Kansas City Power & Light had asked the Missouri commission for a rate increase of $112.7 million (14.9%), based on a return of 10.3% on a 50.09% common-equity ratio. The regulators granted the utility a hike of $89.7 million (11.7%), based on a 9.5% return on a 50.09% common-equity ratio. They instituted a fuel adjustment clause, but did not grant other mechanisms KCP&L sought. New tariffs took effect in mid-September.

KCP&L was expecting a decision on its rate case in Kansas as this report was going to press. The utility was requesting a raise of $67.3 million (12.5%), based on a 10.3% return on a 50.48% common-equity ratio. New tariffs would take effect at the start of October.

A major construction project is going well. KCP&L has a 50% stake in a coal-fired facility that is undergoing an environmental upgrade. This investment is a key reason why the utility filed the aforementioned rate cases. The latest expectation is that it will come in 6% below the budget of $615 million for KCP&L's share of the project.

Earnings are likely to decline this year. Regulatory lag for costs such as property taxes and transmission expense has been a problem for the company for several years, which explains why earned returns on equity have been mediocre. Our earnings estimate of $1.40 a share is near the low end of Great Plains Energy's targeted range of $1.35-$1.60 a share.

Rate relief should produce higher profits in 2016. Another positive factor is the economic improvement that the company's utilities are seeing in their service area. We forecast that Great Plains Energy will achieve its highest share net since 2007.

We think the board of directors will raise the dividend in the fourth quarter. We look for a raise of $0.015 a share (6.1%) in the quarterly disbursement, the same as a year ago.

The dividend yield and 3- to 5-year total return potential of untimely Great Plains Energy stock are about average, for a utility. The recent price is within our 2018-2020 Target Price Range.

Paul E. Debbas, CFA *September 18, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '12 EPS don't add due to change in shs., '14 due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■Div'd reinvest. plan avail. (C) Incl. intang. In '14: $7.81/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '15: 9.5%; in KS in '13: 9.5%; earned on avg. com. eq., '14: 6.8%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	70

IDACORP, INC. NYSE-IDA

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
57.88	15.9	(Trailing: 15.3 Median: 14.0)	0.85	3.4%	VALUE LINE

TIMELINESS 3 Lowered 5/15/15

SAFETY 2 Raised 8/2/13

TECHNICAL 3 Lowered 7/24/15

BETA .80 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+20%)	8%
Low	55	(-5%)	2%

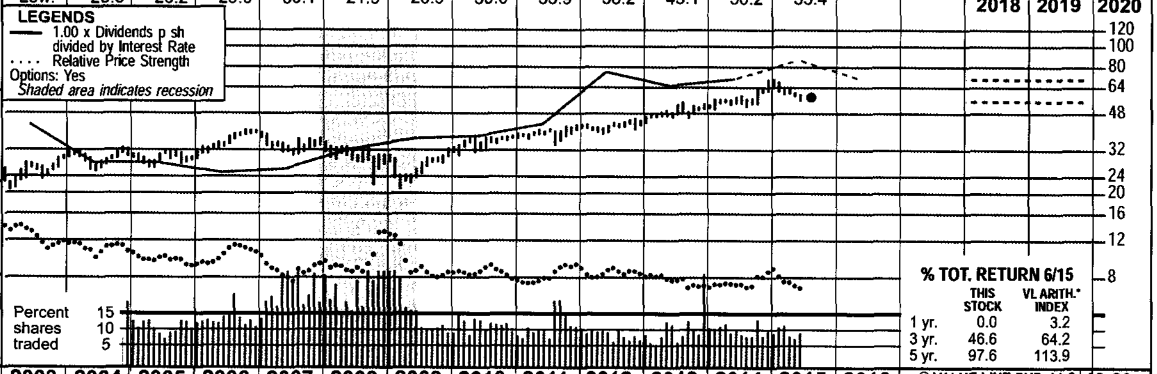
Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	1	2	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	1	1	3	3	1	2	2	1	1

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	70	93	106
to Sell	106	97	92
Hld's(000)	36655	38077	37715

High:	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5
Low:	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4



% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.0	3.2
3 yr.	46.6	64.2
5 yr.	97.6	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.45	26.05	Revenues per sh	27.95
4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.49	6.45	6.70	"Cash Flow" per sh	7.15
2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.65	3.80	Earnings per sh A	3.90
1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.91	2.03	Div'd Decl'd per sh B† ■	2.25
2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	6.05	6.05	Cap'l Spending per sh	6.00
20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.70	42.60	Book Value per sh C	47.05
37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.30	50.30	Common Shs Outst'g D	50.30
12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	16.0
.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.78			Relative P/E Ratio	1.00
6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%			Avg Ann'l Div'd Yield	3.6%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1906.2 mill. **Due in 5 Yrs** $264.5 mill.
LT Debt $1741.7 mill. **LT Interest** $81.0 mill.
(LT interest earned: 3.4x)

Pension Assets-12/14 $559.7 mill.
Oblig. $844.8 mill.

Pfd Stock None

Common Stock 50,347,339 shs.
as of 4/24/15

MARKET CAP: $2.9 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1280	1310	Revenues ($mill)	1405
63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	185	190	Net Profit ($mill)	195
16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	13.4%	28.3%	8.1%	23.0%	23.0%	Income Tax Rate	30.0%
4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	4.4%	7.5%	8.0%	AFUDC % to Net Profit	9.5%
50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.0%	45.0%	Long-Term Debt Ratio	45.0%
50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	55.0%	55.0%	Common Equity Ratio	55.0%
2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3660	3840	Total Capital ($mill)	4330
2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	4095	4300	Net Plant ($mill)	4975
4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.6%	6.5%	6.0%	Return on Total Cap'l	5.5%
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.0%	9.0%	Return on Shr. Equity	8.5%
6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.0%	9.0%	Return on Com Equity E	8.5%
1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.5%	4.0%	Retained to Com Eq	3.5%
80%	51%	64%	55%	46%	41%	36%	41%	43%	46%	52%	53%	All Div'ds to Net Prof	58%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+2.6	+3.8	+1.4
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.63	5.21	5.68
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3245	3407	3184
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.1	+1.5	+1.4
Fixed Charge Cov. (%)	283	329	287

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	3.0%	2.5%
"Cash Flow"	4.5%	6.5%	2.5%
Earnings	9.0%	10.0%	1.0%
Dividends	- -	5.5%	6.0%
Book Value	5.0%	6.0%	4.0%

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	289.8	1282.5
2015	279.4	335.6	395	270	1280
2016	295	335	395	285	1310

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	.85	1.83	.50	3.65
2016	.70	.80	1.80	.50	3.80

Cal-endar	QUARTERLY DIVIDENDS PAID B†■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.30	.30	.30	.30	1.20
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47			

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 3 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles, serving 516,000 business customers. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 45%; commercial, 27%; industrial, 16%; other, 12%. Fuel sources: hydro, 35%; thermal, 40%; purchased power, 25%. '14 depr rate: 3.8%. Has 2,021 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorp: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

Unseasonably warm weather took a toll on first-quarter results at IDACORP's principal operating subsidiary. That unit, electric utility Idaho Power, contributes the vast majority of IDA's revenues and earnings. Warmer-than-normal weather across much of the northwest United States was largely responsible for a decrease in residential sales in the March term. (Idaho Power had approximately 516,000 customers at year-end 2014, and roughly 428,000 of those customers, or 83%, were residential.)

The timing of certain operating and maintenance expenses has also hindered the bottom line. Increased thermal plant maintenance and rising hydroelectric costs reduced first-quarter operating income by $3.0 million, compared with the same period in 2014. Moreover, depreciation expense swelled by $1.2 million, from the year earlier, due to ongoing capital additions. On the plus side, the aforementioned negative factors were offset, at least partially, by Idaho Power's continued customer growth, which contributed $1.9 million to operating income. For the full year, management expects operating and maintenance expense of $340 million–$350 million, capital expenditures of $300 million–$310 million, with share net likely coming in between $3.65 and $3.80.

We expect a 6% dividend increase in 2016, and an average 5% annual raise to decade's end. The payout was held at $1.20 per share for eight years, a streak that was finally broken in 2012. Since then, the board has raised the dividend an average of roughly 12% annually, with the distribution on pace for $1.88 per share in the current year. The yield is below average for an electric utility, but is well above the *Value Line* median, and the payout remains well covered, at approximately 52% of projected 2015 earnings.

Long-term total return potential here is limited. The share price has fluctuated quite a bit over the past 12 months, by the standard of an electric utility stock, ranging between about $50 and $70 over that span. On the plus side, the equity garners a decent mark for Safety (2, Above Average), and earns good scores for Price Stability, Price Growth Persistence, and Earnings Predictability.

Sharif Abdou *July 31, 2015*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in early November.

(B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '14: $25.26/sh. (D) In mill.

(E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '14: 9.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
25.83	15.4	17.9 23.0	0.88	4.8%	VALUE LINE

TIMELINESS 4 Lowered 5/15/15

SAFETY 3 Lowered 12/24/10

TECHNICAL 3 Raised 9/11/15

BETA .85 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+95%)	21%
Low	30	(+15%)	8%

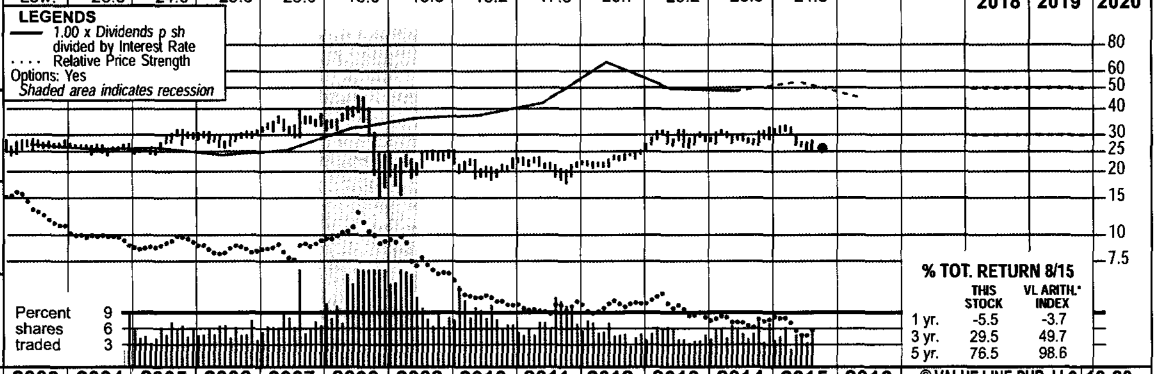
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	1	1	0	0	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	64	50	49
to Sell	41	58	53
Hld's(000)	12708	12560	12614

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	27.5	32.0	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4
Low:	23.8	24.0	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.5	-3.7
3 yr.	29.5	49.7
5 yr.	76.5	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	***21.20***	***22.05***	Revenues per sh	***29.15***
2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	***3.15***	***3.60***	"Cash Flow" per sh	***4.50***
1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	***1.60***	***1.75***	Earnings per sh A	***2.25***
.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	***1.23***	***1.25***	Div'd Decl'd per sh B ■	***1.32***
1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	***4.20***	***4.35***	Cap'l Spending per sh	***4.75***
10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	***16.05***	***16.65***	Book Value per sh C	***18.10***
23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	***38.00***	***39.00***	Common Shs Outst'g D	***42.00***
13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	***Bold figures are***		Avg Ann'l P/E Ratio	***18.0***
.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	***Value Line***		Relative P/E Ratio	***1.15***
4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	***estimates***		Avg Ann'l Div'd Yield	***3.3%***
						1046.4	1105.0	1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	***805***	***860***	Revenues ($mill)	***1225***
						52.9	50.8	54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	***60.0***	***70.0***	Net Profit ($mill)	***95.0***
						34.6%	34.8%	34.1%	30.0%	- -	- -	14.5%	5.2%	21.3%	22.5%	***25.0%***	***25.0%***	Income Tax Rate	***25.0%***
						1.7%	1.9%	4.2%	6.1%	4.0%	.6%	3.8%	1.7%	1.7%	3.6%	***3.0%***	***4.0%***	AFUDC % to Net Profit	***5.0%***
						35.0%	33.5%	38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	***46.5%***	***46.5%***	Long-Term Debt Ratio	***48.0%***
						62.9%	64.5%	59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	***53.5%***	***53.5%***	Common Equity Ratio	***52.0%***
						738.2	763.0	882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	***1135***	***1210***	Total Capital ($mill)	***1460***
						697.1	718.6	854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	***1350***	***1450***	Net Plant ($mill)	***1750***
						8.3%	7.7%	7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.5%***
						11.0%	10.0%	10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	***10.0%***	***11.0%***	Return on Shr. Equity E	***12.5%***
						11.2%	10.2%	10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	***10.0%***	***11.0%***	Return on Com Equity	***12.5%***
						4.2%	3.3%	3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	***2.0%***	***3.0%***	Retained to Com Eq	***5.0%***
						63%	68%	66%	108%	NMF	NMF	NMF	113%	87%	78%	***79%***	***71%***	All Div'ds to Net Prof	***59%***

CAPITAL STRUCTURE as of 6/30/15
Total Debt $541.6 mill. **Due in 5 Yrs** $87.0 mill.
LT Debt $498.4 mill. **LT Interest** $28.0 mill.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/14 $244.6 mill. **Oblig.** $311.7 mill.
Pfd Stock None

Common Stock 37,591,785 shs.
as of 7/31/15
MARKET CAP: $975 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.1	+5.8	+4.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	257	359	336

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '12-'14 to '18-'20**
Revenues	-2.0%	-8.5%	*4.0%*
"Cash Flow"	-1.0%	-.5%	*7.5%*
Earnings	-2.0%	2.0%	*9.0%*
Dividends	1.0%	- -	*1.5%*
Book Value	1.0%	-4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	219.9	211.4	215.3	212.6	859.2
2013	218.0	212.4	229.8	233.1	893.3
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	***205***	***209***	***805***
2016	***215***	***210***	***215***	***220***	***860***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.19	.13	.47	1.05
2013	.41	.21	.41	.35	1.37
2014	.59	.27	.43	.28	1.55
2015	.37	.36	***.44***	***.43***	***1.60***
2016	***.45***	***.35***	***.48***	***.47***	***1.75***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.298	.298	.298	.298	1.19
2012	.298	.298	.298	.298	1.19
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (50% of retail elec. revs.), North Dakota (42%), and South Dakota (8%). Electric rev. breakdown, '14: residential, 32%; commercial & farms, 37%; industrial, 25%; other, 6%. Fuel costs: 16.6% of revenues. Also has operations in manufacturing and plastics. 2014 depr. rate: 2.9%. Has 1,893 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 9.3%; Vanguard Group, Inc., 6.6%; BlackRock, Inc., 5.5% (2/15 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Otter Tail reported mixed results for the June quarter. The top line declined roughly 3% on a year-over-year basis. The softness was broad based, as revenue decreased in each of the company's three operating segments. Still, greater transmission tariff revenues provided support at Otter Tail Power Company. Moreover, the bottom line benefited from lower operating and maintenance expenses. Overall, share net of $0.36 compared favorably with the prior-year tally.

Subsidiary BTD Manufacturing has acquired Impulse Manufacturing for $30.5 million. The addition of this Georgia-based company will allow BTD to accelerate its plans to expand into the southeastern United States. The acquisition is expected to be accretive to earnings in 2016.

Challenges will likely persist in the near term, but we expect solid overall performance going forward. Net income for the electric segment this year should increase at a moderate rate. This line ought to benefit from rider recovery increases, greater sales to pipeline customers, and a decline in plant maintenance costs. That said, this should be partly offset by softness in retail sales due to milder-than-normal weather, a decline in transmission revenue, and an increase in depreciation, property tax expense, and short-term interest costs. Elsewhere, earnings from the Manufacturing and Plastics segments may well decline for 2015. Softness in various end markets served by BTD's customers should continue to hurt performance at the Manufacturing line. A decrease in sales of polyvinyl chloride pipe will likely hurt results at the Plastics business, but this ought to be partly offset by lower material costs.

These shares are ranked to lag the overall market for the coming six to 12 months. This stock has traded lower over the past six months, and the weakness may well continue going forward. But patient, income-seeking accounts may want to take a closer look. Earnings growth ought to pick up at Otter Tail as demand improves down the road. This equity offers solid total return potential for the pull to late decade, which is supported by a healthy dividend yield.

Michael Napoli, CFA *September 18, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '99, 34¢; '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢. Earnings may not sum due to rounding. Next earnings report due early November. **(B)** Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. intangibles. In '14: $42.7 mill., $1.15/sh. **(D)** In mill.
(E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	15
Earnings Predictability	50

PINNACLE WEST NYSE-PNW

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
59.96	15.6 (Trailing: 16.7 Median: 15.0)	0.83	4.1%	VALUE LINE

TIMELINESS 3 Lowered 10/10/14

SAFETY 1 Raised 5/3/13

TECHNICAL 3 Lowered 7/24/15

BETA .70 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+15%)	*8%*
Low	55	(-10%)	*3%*

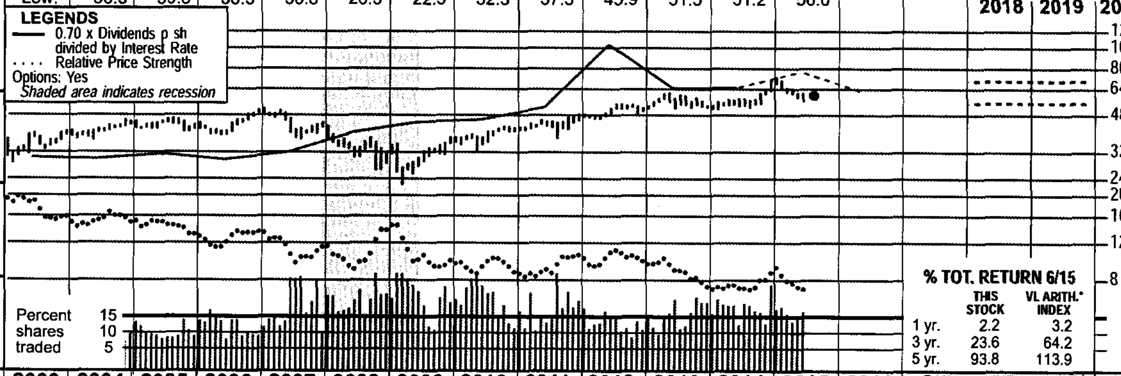
Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	3	0	0	1	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	171	191	182
to Sell	163	188	194
Hld's(000)	88791	88401	86769

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3
Low:	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0



Target Price Range
2018 | 2019 | 2020

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.2	3.2
3 yr.	23.6	64.2
5 yr.	93.8	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	*31.55*	*32.75*	Revenues per sh	*36.50*
7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	*8.75*	*9.10*	"Cash Flow" per sh	*10.25*
3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	*3.85*	*3.95*	Earnings per sh A	*4.50*
1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	*2.44*	*2.56*	Div'd Decl'd per sh B ■	*2.95*
4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	*9.85*	*9.90*	Cap'l Spending per sh	*9.75*
26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	*40.95*	*42.30*	Book Value per sh C	*47.00*
84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	*111.00*	*111.50*	Common Shs Outst'g D	*118.00*
11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84			Relative P/E Ratio	*.85*
3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%			Avg Ann'l Div'd Yield	*4.8%*
						2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	*3500*	*3650*	Revenues ($mill)	*4300*
						223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	*430*	*445*	Net Profit ($mill)	*540*
						36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
						43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	*44.5%*	*45.0%*	Long-Term Debt Ratio	*44.5%*
						56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	*55.5%*	*55.0%*	Common Equity Ratio	*55.5%*
						6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	*8200*	*8610*	Total Capital ($mill)	*10025*
						7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	*11750*	*12275*	Net Plant ($mill)	*14200*
						5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
						6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
						6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	*9.5%*	*9.5%*	Return on Com Equity E	*9.5%*
						1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
						85%	63%	70%	96%	89%	66%	68%	58%	58%	62%	*63%*	*64%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $3699.4 mill. **Due in 5 Yrs** $1474.1 mill.
LT Debt $3281.3 mill. **LT Interest** $165.9 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/14 $2615.4 mill.
Oblig. $3078.7 mill.
Pfd Stock None

Common Stock 110,748,842 shs.
as of 4/24/15
MARKET CAP: $6.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.2	-.2	-1.8
Avg. Indust. Use (MWH)	647	644	659
Avg. Indust. Revs. per KWH (¢)	7.86	8.21	8.26
Capacity at Peak (Mw)	8864	8398	9259
Peak Load, Summer (Mw)	7207	6927	7007
Annual Load Factor (%)	48.8	50.0	48.6
% Change Customers (yr-end)	+1.3	+1.4	+1.2
Fixed Charge Cov. (%)	397	419	404

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	- -	-1.5%	*3.0%*
"Cash Flow"	1.5%	-1.0%	*4.0%*
Earnings	3.5%	8.0%	*4.0%*
Dividends	3.5%	3.0%	*3.5%*
Book Value	2.0%	2.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	*925*	*1178.8*	*725*	*3500*
2016	*700*	*975*	*1225*	*750*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	*1.25*	*2.26*	*.20*	*3.85*
2016	*.15*	*1.30*	*2.30*	*.20*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015	.595	.595			

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 48%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 34%; nuclear, 27%; gas & other, 17%; purchased, 22%. Fuel costs: 34% of revenues. Has 6,400 employees. '14 reported deprec. rate: 2.8%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is awaiting a regulatory ruling from the Arizona commission. In early April, Arizona Public Service proposed increasing the monthly fixed charge for residential customers from about $5 to about $21. The utility is concerned that nonsolar customers are subsidizing solar users under the current rate structure. An administrative law judge will weigh in on this matter before the commission issues its order. There is no time frame for conclusion of these proceedings.

The utility plans to add some generating capacity by late decade. APS intends to build 510 megawatts of gas-fired capacity at a cost of $500 million. It will retire some older units that amount to 220 mw, for a net capacity addition of 290 mw. Pending the receipt of an environmental permit, construction is expected to begin next year, with completion of the project planned for 2019.

We estimate that earnings will rise at a high single-digit pace in 2015. APS received a $57.1 million rate increase at the start of the year in order to place a newly purchased asset (a stake in Units 4 and 5 of the Four Corners coal-fired plant) in the rate base. In addition, the utility receives current cost recovery for certain kinds of capital spending, such as electric transmission. Our earnings estimate remains at the midpoint of Pinnacle West's targeted range of $3.75-$3.95 a share.

We forecast a lesser profit increase in 2016. The regulatory mechanisms mentioned above should benefit the company. However, although customer growth is likely to exceed the 1% level, volume is expected to advance at just 0.5% due to the effects of conservation.

Finances are strong. The fixed-charge coverage is well above the industry average. The common-equity ratio is among the highest of any utility, and APS is earning near its allowed return on equity. All told, Pinnacle West merits a Financial Strength rating of A+.

Top-quality Pinnacle West stock has a dividend yield that is roughly equal to the utility mean. Although we project decent dividend growth over the period to 2018-2020, total return potential is only average for the group.

Paul E. Debbas, CFA *July 31, 2015*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from discontinued ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Next earnings report due early Aug. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '14: $12.30/sh. **(D)** In mill. **(E)** Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '14: 9.3%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	70

PNM RESOURCES NYSE-PNM

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
25.30	16.3 (Trailing: 16.6 Median: 16.0)	0.87	3.2%

VALUE LINE

TIMELINESS 3 Lowered 6/19/15
SAFETY 3 Lowered 5/9/08
TECHNICAL 5 Lowered 7/31/15
BETA .85 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+80%)	*18%*
Low	30	(+20%)	*8%*

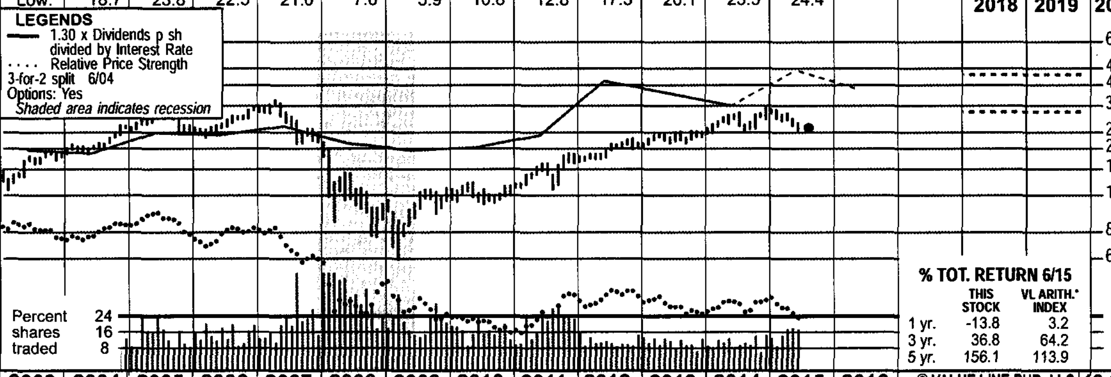
Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	1	0	0
Options	0	0	0	0	0	0	4	0	0
to Sell	0	0	0	0	0	0	4	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	86	109	108
to Sell	101	93	110
Hld's(000)	71291	71113	69125

High:	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2
Low:	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4



% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-13.8	3.2
3 yr.	36.8	64.2
5 yr.	156.1	113.9

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	**18.25**	**18.75**	Revenues per sh	**20.30**
2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.67	**3.70**	**3.85**	"Cash Flow" per sh	**4.70**
1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.49	**1.55**	**1.65**	Earnings per sh A	**2.35**
.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.74	**.80**	**.85**	Div'd Decl'd per sh B ■†	**1.15**
1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	**5.50**	**5.50**	Cap'l Spending per sh	**5.50**
14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	21.61	**22.10**	**22.70**	Book Value per sh C	**25.50**
61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	**80.00**	**80.00**	Common Shs Outst'g D	**80.00**
9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.1	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.90	*Value Line*		Relative P/E Ratio	**1.00**
4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	3.5%	*estimates*		Avg Ann'l Div'd Yield	**3.3%**
						2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	**1460**	**1500**	Revenues ($mill)	**1625**
						106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	119.6	**125**	**135**	Net Profit ($mill)	**190**
						31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	**36.7%**	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
						15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	**1.5%**	**2.5%**	AFUDC % to Net Profit	**8.0%**
						57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	48.8%	**52.0%**	**53.0%**	Long-Term Debt Ratio	**53.5%**
						42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.2%	**48.0%**	**47.0%**	Common Equity Ratio	**46.5%**
						3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3363.6	**3695**	**3845**	Total Capital ($mill)	**4385**
						2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	**4335**	**4555**	Net Plant ($mill)	**5270**
						4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	**5.3%**	**5.0%**	**5.0%**	Return on Total Cap'l	**6.0%**
						8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.9%	**7.0%**	**7.5%**	Return on Shr. Equity	**9.5%**
						8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.9%	**7.0%**	**7.5%**	Return on Com Equity E	**9.5%**
						4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.5%	**3.5%**	**3.5%**	Retained to Com Eq	**5.0%**
						48%	49%	117%	NMF	86%	58%	47%	43%	45%	49%	**51%**	**51%**	All Div'ds to Net Prof	**49%**

CAPITAL STRUCTURE as of 3/31/15
Total Debt $2225.0 mill. **Due in 5 Yrs** $1112 mill.
LT Debt $1791.9 mill. **LT Interest** $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/14 $657.6 mill.
Oblig. $587.7 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 4/24/15
MARKET CAP: $2.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICSF

	2012	2013	2014
% Change Retail Sales (KWH)	-1.6	-2.9	-2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2537	2572	2707
Peak Load, Summer (Mw)	1948	2008	1948
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.7	+.6
Fixed Charge Cov. (%)	225	241	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-4.0%	-7.0%	*1.5%*
"Cash Flow"	--	5.0%	*5.0%*
Earnings	-2.5%	8.0%	*9.0%*
Dividends	.5%	-6.0%	*10.0%*
Book Value	1.5%	-1.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	**355**	**440**	**332.1**	**1460**
2016	**345**	**360**	**440**	**355**	**1500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.18	.39	.68	.24	1.49
2015	.21	**.40**	**.75**	**.19**	**1.55**
2016	**.25**	**.40**	**.75**	**.25**	**1.65**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.125	.125	.125	.125	.50
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20			

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '14: residential, 37%; commercial, 37%; industrial, 6%; other, 20%. Fuels: coal, 56.8%; nuclear, 30.4%; gas/oil, 12.2%; solar, .5%. Fuel costs: 49% of revs. '14 depr. rate: 3.3%. Has 1,881 employees. Chrmn., Pres. & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources appealed the future test-year ruling to the New Mexico Supreme Court. The company's rate case was reviewed in April by the examiner, which recommended rejection since it did not comply with the future test-year rule. The utility was looking for a revenue increase of $107.4 million and a return on equity of 10.5%. There should be a ruling on the appeal within the year.

The company is about to file the San Juan Participation agreement. The related coal contract allows PNM to illustrate that its plan is the lowest-cost option for its ratepayers. The outcome of this agreement will have an impact on the San Juan units. The final order is expected at the end of 2015.

Some regulatory matters are upcoming. The utility is seeking changes to its rate design to improve the distribution of its costs in New Mexico. While new rates will probably be delayed until at least mid-2016, the company is taking the proper steps to move ahead in that time frame. Interested investors should keep an eye on this situation as it represents a potential catalyst for PNM shares. Also of note, new rates would help the utility keep up with rising capital expenditures.

We are leaving our estimates intact. The company's regulatory operations have performed well of late. Recent investments in the PNM operations should bolster results in the months ahead. Additionally, rate growth in Texas has been a positive. Accordingly, we look for earnings of $1.55 a share this year and for them to advance by a dime, to $1.65 a share, next year. Looking further out, the company has some interesting prospects over the pull to 2018-2020. Efforts to develop infrastructure for clean energy represent a promising growth avenue. What's more, the aforementioned rate case could bolster results in New Mexico. Lastly, steady dividend hikes ought to sweeten the pot.

PNM stock is attractive for income-oriented investors. Indeed, this equity's yield (3.2%) coupled with its projected dividend growth rate (10%) makes PNM an interesting choice. Moreover, this issue has fallen in value since our May review. As a result, total return potential over the 3- to 5-year pull is appealing.

Richard J. Gallagher *July 31, 2015*

(A) EPS dil. Excl. n/r gains (losses): '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13,(16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late October. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '14: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	25

PORTLAND GENERAL NYSE-POR

RECENT PRICE 33.99 **P/E RATIO** 15.8 (Trailing: 16.4 Median: NMF) **RELATIVE P/E RATIO** 0.84 **DIV'D YLD** 3.6% **VALUE LINE**

TIMELINESS 4 Lowered 7/17/15

SAFETY 2 Raised 5/4/12

TECHNICAL 3 Lowered 7/24/15

BETA .80 (1.00 = Market)

2018-20 PROJECTIONS

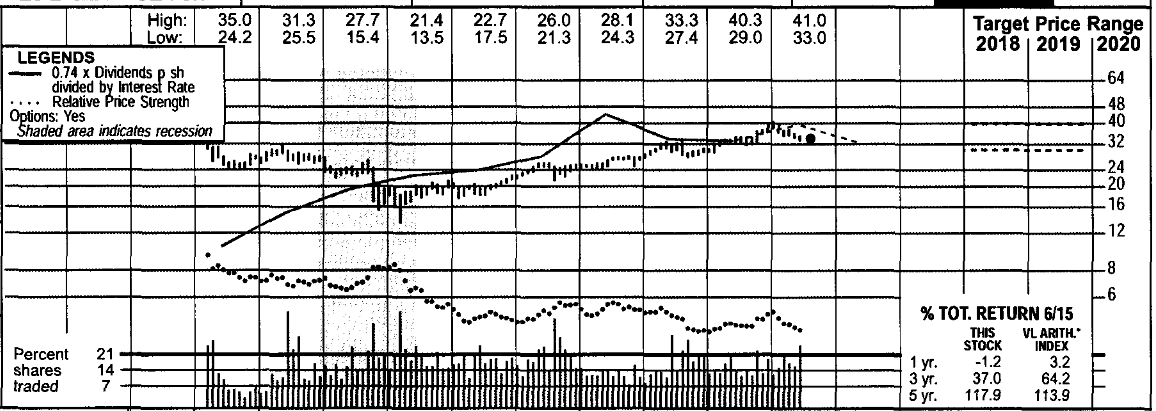
	Price	Gain	Ann'l Total Return
High	40	(+20%)	*8%*
Low	30	(-10%)	*1%*

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	1

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	123	132	122
to Sell	116	127	142
Hld's(000)	83632	82456	84710



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0

LEGENDS
—— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range
2018 | 2019 | 2020

% TOT. RETURN 6/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.2	3.2
3 yr.	37.0	64.2
5 yr.	117.9	113.9

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2005G	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	*21.15*	*22.50*	Revenues per sh	*24.25*
4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	*5.50*	*5.95*	"Cash Flow" per sh	*7.00*
1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	*2.15*	*2.40*	Earnings per sh A	*2.75*
--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	*1.18*	*1.26*	Div'd Decl'd per sh B ■ †	*1.50*
4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	*7.15*	*4.40*	Cap'l Spending per sh	*3.50*
19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	*25.60*	*26.75*	Book Value per sh C	*30.50*
62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	*88.70*	*88.90*	Common Shs Outst'g D	*89.50*
--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*12.5*
--	1.26	.63	.98	.96	.76	.78	.89	.95	.81			Relative P/E Ratio	*.80*
--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%			Avg Ann'l Div'd Yield	*4.4%*
1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	*1875*	*2000*	Revenues ($mill)	*2175*
64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	*180*	*215*	Net Profit ($mill)	*255*
40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	*14.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	*48.5%*	*48.5%*	Long-Term Debt Ratio	*48.5%*
57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	*51.5%*	*51.5%*	Common Equity Ratio	*51.5%*
2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	*4405*	*4625*	Total Capital ($mill)	*5300*
2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	*6010*	*6085*	Net Plant ($mill)	*6000*
4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*8.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	*8.0%*	*9.0%*	Return on Com Equity E	*9.5%*
5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	*3.5%*	*4.5%*	Retained to Com Eq	*4.5%*
--	39%	40%	69%	76%	62%	54%	57%	61%	50%	*54%*	*52%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $2456 mill. **Due in 5 Yrs** $822 mill.
LT Debt $2134 mill. **LT Interest** $113 mill.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/14 $591 mill.
Oblig. $777 mill.

Pfd Stock None

Common Stock 78,344,941 shs.
as of 4/22/15

MARKET CAP: $2.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-.8	+1.2	-.8
Avg. Indust. Use (MWH)	16409	16258	16577
Avg. Indust. Revs. per KWH (¢)	5.26	4.84	5.13
Capacity at Peak (Mw)	4173	4380	4910
Peak Load, Winter (Mw) F	3597	3869	3866
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.9	+.7
Fixed Charge Cov. (%)	270	239	248

ANNUAL RATES of change (per sh)	*Past* 10 Yrs.	*Past* 5 Yrs.	*Est'd '12-'14* to '18-'20
Revenues	--	-2.0%	*.5%*
"Cash Flow"	--	3.0%	*4.5%*
Earnings	--	3.0%	*6.0%*
Dividends	--	2.5%	*5.5%*
Book Value	--	2.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.0	413.0	450.0	463.0	1805.0
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	*440*	*485*	*477*	*1875*
2016	*525*	*460*	*505*	*510*	*2000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	*.45*	*.50*	*.58*	*2.15*
2016	*.80*	*.47*	*.53*	*.60*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.26	.26	.265	.265	1.05
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30		

BUSINESS: Portland General Electric Company (PGE) provides electricity to 844,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 34%; industrial, 12%; other, 7%. Generating sources: coal, 21%; gas, 16%; hydro, 8%; wind, 6%; purchased, 49%. Fuel costs: 38% of revenues. '14 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has settled most issues of its rate case. The utility is seeking a rate hike of $17.8 million, which would take effect at the start of 2016. PGE is building a 440-megawatt gas-fired generating plant, which is expected to go on line in the second quarter of 2016 at a cost of $450 million. The utility is asking for an additional tariff hike of $84.7 million that would take effect when the new generating facility becomes used and useful. The application is based on a return of 9.9% on a common-equity ratio of 50%. PGE has reached a settlement with the staff of the Oregon Public Utility Commission (OPUC) and some intervenors on all issues except one that is related to power costs. However, details of the settlement will not be available for at least a few weeks. The OPUC's order is expected in late 2015.

The board of directors raised the dividend significantly. It increased the quarterly disbursement by two cents a share (7.1%). This was by far the biggest hike since PGE reemerged as a public company in 2006. There was plenty of room for the directors to boost the dividend, considering that the payout ratio remains near the low end of the company's targeted range of 50%-70%. PGE has established a goal of 5%-7% annual dividend growth.

We have lowered our 2015 earnings estimate by $0.15 a share. The utility's service area had the warmest winter on record, which reduced profits by $0.20 a share versus normal weather. Management has cut its earnings guidance by $0.15, to $2.05-$2.20 a share. PGE believes it can make up part of the lost income through cost reductions.

We forecast much higher profits next year. This is based on the expectation of rate relief from the aforementioned rate case, and the assumption that the winter weather patterns will be normal.

This untimely stock's dividend yield and 3- to 5-year total return potential are slightly below the utility averages. The stock's valuation might well reflect some takeover speculation, but we would not buy it in the hope of a buyout. A takeover attempt more than 10 years ago proved to be unsuccessful.

Paul E. Debbas, CFA *July 31, 2015*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due late Oct. **(B)** *Dividends paid mid-Jan., Apr., July, and* Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '14: $6.31/sh. **(D)** In mill. **(E)** *Rate base: Net original cost. Rate allowed* on com. eq. in '15: 9.68%; earned on avg. com. eq., '14: 9.4%. Regulatory Climate: Below Average. **(F)** Summer peak in '12. **(G)** '05 per-*share data are pro forma, based on shares out-*standing when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	65

SOUTHERN COMPANY NYSE-SO

RECENT PRICE	45.91	P/E RATIO	16.5 (Trailing: 17.1 Median: 16.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	4.8%

VALUE LINE

TIMELINESS 4 Lowered 7/17/15

SAFETY 2 Lowered 2/21/14

TECHNICAL 5 Lowered 8/7/15

BETA .55 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	9%
Low	40	(-15%)	2%

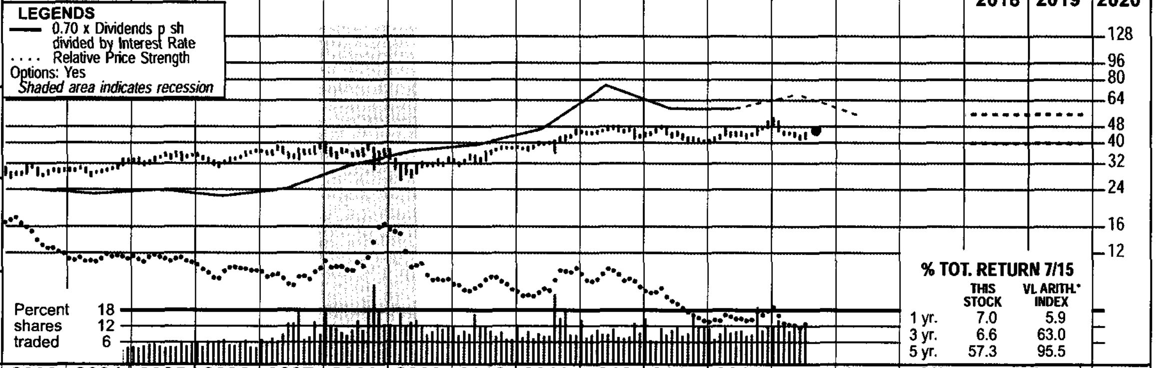
Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	1
Options	1	3	1	1	0	3	0	0	0
to Sell	1	3	1	1	0	3	0	0	0

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	454	515	504
to Sell	370	382	444
Hld's(000)	450922	462861	452667

High:	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2
Low:	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3	41.4



% TOT. RETURN 7/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.0	5.9
3 yr.	6.6	63.0
5 yr.	57.3	95.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	***20.05***	***21.05***	Revenues per sh	***24.00***
4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	***5.35***	***5.60***	"Cash Flow" per sh	***6.50***
1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	***2.80***	***2.95***	Earnings per sh A	***3.50***
1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	***2.15***	***2.22***	Div'd Decl'd per sh B ■ †	***2.43***
3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	***7.35***	***6.00***	Cap'l Spending per sh	***6.50***
13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	***22.55***	***23.25***	Book Value per sh C	***26.00***
665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	***911.00***	***913.00***	Common Shs Outst'g D	***919.00***
14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.5***
.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.85			Relative P/E Ratio	***.85***
5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%			Avg Ann'l Div'd Yield	***5.2%***
						13554	14356	15353	17127	15743	17456	17657	16537	17087	18467	***18250***	***19200***	Revenues ($mill)	***22000***
						1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	2567.0	***2635***	***2765***	Net Profit ($mill)	***3300***
						26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	33.8%	***33.0%***	***33.0%***	Income Tax Rate	***33.0%***
						4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	13.9%	***14.0%***	***13.0%***	AFUDC % to Net Profit	***12.0%***
						53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	49.5%	***53.0%***	***55.0%***	Long-Term Debt Ratio	***57.5%***
						44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	47.3%	***44.0%***	***42.5%***	Common Equity Ratio	***40.5%***
						24131	24618	27608	31174	34091	35438	37307	38653	41483	42142	***46450***	***49925***	Total Capital ($mill)	***59200***
						29480	31092	33327	35878	39230	42002	45010	48390	51208	54868	***59275***	***62375***	Net Plant ($mill)	***70000***
						8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	7.1%	***6.5%***	***6.5%***	Return on Total Cap'l	***6.5%***
						14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	12.1%	***12.0%***	***12.0%***	Return on Shr. Equity	***13.0%***
						14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	12.5%	***12.5%***	***13.0%***	Return on Com Equity E	***13.5%***
						4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	3.2%	***3.0%***	***3.0%***	Retained to Com Eq	***4.0%***
						70%	73%	70%	74%	75%	77%	73%	73%	75%	75%	***76%***	***75%***	All Div'ds to Net Prof	***69%***

CAPITAL STRUCTURE as of 3/31/15
Total Debt $26078 mill. **Due in 5 Yrs** $10464 mill.
LT Debt $21093 mill. **LT Interest** $778 mill.
(LT interest earned: 5.0x)
Leases, Uncapitalized Annual rentals $100 mill.
Pension Assets-12/14 $9690 mill. **Ob** $10909 mill.
Pfd Stock $1352 mill. **Pfd Div'd** $68 mill.
Incl. 1 mill. shs. 4.2%-5.44% cum. pfd. ($100 par); 12 mill. shs. 5.2%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 4 mill. shs. 5.6%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 908,261,371 shs.
MARKET CAP: $42 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.3	+.3	+3.3
Avg. Indust. Use (MWH)	3229	3277	3384
Avg. Indust. Revs. per KWH (¢)	5.94	6.08	6.37
Capacity at Yearend (Mw)	45750	45502	46549
Peak Load, Summer (Mw) F	35479	33557	37234
Annual Load Factor (%)	59.5	63.2	59.6
% Change Customers (yr-end)	+.5	+.7	+.8
Fixed Charge Cov. (%)	416	423	417

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	2.5%	-1.0%	*3.5%*
"Cash Flow"	4.0%	3.5%	*3.5%*
Earnings	3.5%	3.5%	*4.5%*
Dividends	4.0%	4.0%	*3.0%*
Book Value	5.0%	4.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3604	4181	5049	3703	16537
2013	3897	4246	5017	3927	17087
2014	4644	4467	5339	4017	18467
2015	4183	4337	***5580***	***4150***	***18250***
2016	***4400***	***4700***	***5800***	***4300***	***19200***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.42	.71	1.11	.43	2.67
2013	.47	.66	1.08	.49	2.70
2014	.66	.68	1.08	.36	2.77
2015	.56	.71	***1.16***	***.37***	***2.80***
2016	***.55***	***.80***	***1.20***	***.40***	***2.95***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49	.49	.49	1.94
2013	.49	.5075	.5075	.5075	2.01
2014	.5075	.525	.525	.525	2.08
2015	.525	.5425			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.5 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 37%; commercial, 31%; industrial, 19%; other, 13%. Retail revenues by state: Georgia, 51%; Alabama, 33%; Florida, 9%; Mississippi, 7%. Generating sources: coal, 39%; oil & gas, 37%; nuclear, 15%; hydro, 3%; purchased, 6%. Fuel costs: 36% of revenues. '14 reported deprec. rate (utility): 3.1%. Has 26,400 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

Southern Company's Mississippi Power subsidiary has filed a general rate case. Mississippi Power is building a coal gasification plant that has experienced significant cost overruns. It is now expected to cost almost $5 billion. (The latest nonrecurring charge, in the June quarter, reduced share net by $0.02.) The project is already producing some electricity, but won't be completed until the second quarter of 2016. After the state Supreme Court found that a rate hike in 2013 (which put a cost cap of $2.88 billion on the project) was illegal, the commission ordered the utility to refund $353 million that it collected since then. (This benefited cash flow, but was not included in earnings, so there won't be charge for the refund.) Accordingly, Mississippi Power has filed for an interim rate hike of $159 million (18%), based on a 9.7% return on a 50% common-equity ratio, until it can get permanent tariffs in place.

The company's nuclear construction project has also had some delays and cost overruns. The latest estimate for the two units that Georgia Power is building at the Vogtle station is $7.5 billion (including financing costs) for the two units that are scheduled for completion in June of 2019 and 2020. This doesn't necessarily mean that the utility will have to take a writedown. It might be able to recoup some of the overruns from its contractors.

We estimate just a modest earnings increase in 2015. The March-quarter comparison was tough, due in part to an unusually cold winter in the first period of 2014. However, the company is benefiting from rate relief, the economic recovery in its service territory, and investments by the Southern Power nonutility subsidiary. Our estimate is within the company's guidance of $2.76-$2.88 a share.

We forecast a stronger profit increase in 2016. Rate relief, higher kilowatt-hour sales, and growth at Southern Power should continue to benefit the company.

Southern Company stock is untimely, but offers one of the highest dividend yields of any utility issue. The valuation reflects the construction risk the company is facing. Total return potential to 2018-2020 is no better than the industry average, however.

Paul E. Debbas, CFA *August 21, 2015*

(A) Diluted EPS. Excl. nonrec. gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (59¢); '15, (2¢). '14 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '14: $7.92/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. All'd return on com. eq. (blended): 12.5%; earn. on avg. com. eq., '14: 12.7%. Reg. Clim.: GA, AL Above Avg.; MS, FL Avg. (F) Winter peak in '14.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	100

WESTAR ENERGY NYSE-WR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
35.94	15.2	15.8 14.0	0.87	4.0%	VALUE LINE

TIMELINESS 3 Lowered 12/12/14

SAFETY 2 Raised 4/1/05

TECHNICAL 2 Raised 9/18/15

BETA .75 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+40%)	12%
Low	40	(+10%)	7%

Insider Decisions

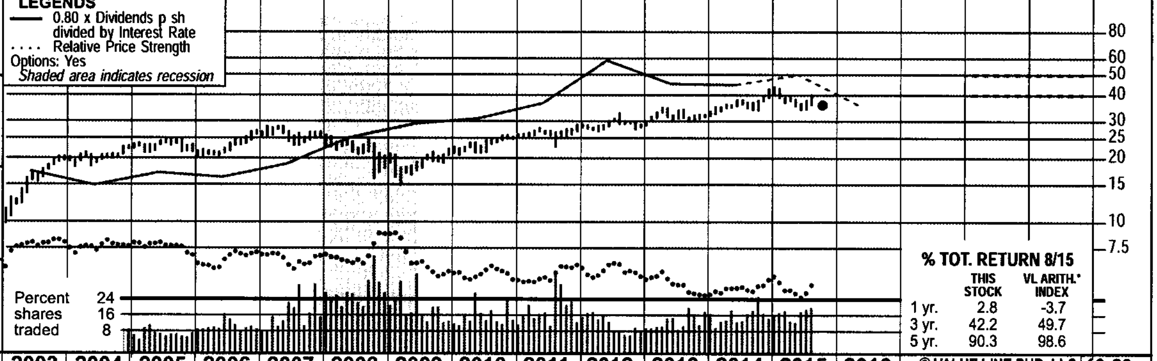
	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	5	0	1	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	157	134	146
to Sell	136	155	125
Hld's(000)	96912	97474	97324

High:	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0
Low:	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9

Target Price Range
2018 | 2019 | 2020



% TOT. RETURN 8/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.8	-3.7
3 yr.	42.2	49.7
5 yr.	90.3	98.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	*19.85*	*19.75*	Revenues per sh	*20.75*
7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	*4.70*	*4.95*	"Cash Flow" per sh	*5.25*
1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	*2.25*	*2.45*	Earnings per sh A	*3.00*
2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.50*	Div'd Decl'd per sh B■†	*1.65*
4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	*7.00*	*7.20*	Cap'l Spending per sh	*8.15*
27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	*25.60*	*26.35*	Book Value per sh C	*29.25*
67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	*130.00*	*135.00*	Common Shs Outst'g E	*140.00*
17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81			Relative P/E Ratio	*.95*
8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%			Avg Ann'l Div'd Yield	*3.7%*
						1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	*2580*	*2665*	Revenues ($mill)	*2800*
						134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	*295*	*335*	Net Profit ($mill)	*420*
						31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
						--	--	10.4%	--	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
						52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
						47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
						3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	*6650*	*6800*	Total Capital ($mill)	*7500*
						3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8500*	Net Plant ($mill)	*9000*
						6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
						9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
						4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						55%	49%	53%	80%	87%	63%	65%	57%	56%	55%	*61%*	*59%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 6/30/15
Total Debt $3398.8 mill. **Due in 5 Yrs** $725.0 mill.
LT Debt $3091.7 mill. **LT Interest** $55.0 mill.
(LT interest earned: 2.8x)

Pension Assets 12/14 $661 mill. **Oblig.** $914 mill.

Pfd Stock None

Common Stock 137,412,152 shs.
MARKET CAP: $4.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.5	+3.6	+1.5
Avg. Indust. Use (MWH)	5588	5407	5747
Avg. Indust. Revs. per KWH (¢)	6.60	6.47	6.72
Capacity at Peak (Mw)	6557	6671	6698
Peak Load, Summer (Mw)	5411	5489	5226
Annual Load Factor (%)	56.0	55.9	56.2
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	319	323	332

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	1.5%	*2.5%*
"Cash Flow"	1.5%	5.0%	*4.5%*
Earnings	6.5%	9.0%	*6.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	5.0%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	*784*	*615.6*	*2580*
2016	*650*	*645*	*775*	*595*	*2665*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	*1.05*	*.36*	*2.25*
2016	*.50*	*.45*	*1.15*	*.35*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.36	.36	.36		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 41%; commercial, 38%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2014 depreciation rate: 3.9%. Estimated plant age: 16 years. Fuels: coal, 48%; nuclear, 8%; gas, 44%. Has 2,411 employees. BlackRock Inc owns 7.2% of common; The Vanguard Group owns 6.3%; Stowers Institute owns 5.7% (4/15 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy's rate case before the Kansas Corporation Commission (KCC) has taken a turn. In March, the utility sought to raise customer rates 8%, or $152 million, but has since cut that number by half, to about a 4% hike, or $78 million. The case is now under review by the KCC, which has until October 28th to accept, decline, or revise the proposed agreement. Management believes that the increases are necessary to help cover the cost of plant upgrades and regulatory compliance. The company also proposed a five-year, $220 million plan to upgrade its electrical grid and a 10% annual profit for shareholders.

Costs for the recently completed air quality controls at the La Cygne Energy Center came in $22 million below expectations. This was the primary reason that management revised its rate requests lower. The company also spent less than originally forecasted on the life extension of the Wolf Creek facility.

New regulation from the Environmental Protection Agency (EPA) should prompt further overhauls. The Clean Power Plan is a set of rules meant to limit the amount of carbon emissions from utilities. The plan was announced just a few weeks ago and will likely be challenged in the courts by several different opponents. However, carbon emissions regulation is not going away, and management seems cognizant of the fact that it needs to upgrade its coal-based plants to cleaner energy, like natural gas.

Lower oil prices have been a drag lately. Industrial customers, such as chemical manufacturers and pipeline operators, have taken a big hit due to lower oil prices and have thus cut their energy usage by several megawatts. On the positive side, refineries and consumer discretionary-based customers remain in good shape. Management also announced that a large confectionery company is planning a big expansion that should add a few megawatts to sales.

At recent prices, Westar's dividend yield is around average for electric utilities. That said, conservative investors may still want to look here as the combination of appreciation potential and safety is still attractive.

Daniel Henigson *September 18, 2015*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early November. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014: $6.48/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	90

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Thu, Oct 29, 2015, 6:17PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

ALLETE, Inc. (ALE) - NYSE

49.90 0.43(0.85%) 4:02PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.02	0.88	3.26	3.37
No. of Analysts	6.00	5.00	5.00	7.00
Low Estimate	0.95	0.71	3.05	3.27
High Estimate	1.11	0.99	3.35	3.60
Year Ago EPS	0.97	0.73	2.99	3.26

Next Earnings Date: Nov 3, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	354.00M	353.00M	1.27B	1.33B
No. of Analysts	1	1	5	5
Low Estimate	354.00M	353.00M	1.11B	1.15B
High Estimate	354.00M	353.00M	1.35B	1.47B
Year Ago Sales	288.90M	290.70M	1.14B	1.27B
Sales Growth (year/est)	22.50%	21.40%	11.40%	5.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.72	0.68	0.87	0.50
EPS Actual	0.97	0.73	0.91	0.48
Difference	0.25	0.05	0.04	-0.02
Surprise %	34.70%	7.40%	4.60%	-4.00%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.02	0.88	3.26	3.37
7 Days Ago	1.02	0.88	3.26	3.37
30 Days Ago	1.00	0.91	3.25	3.39
60 Days Ago	1.00	0.91	3.25	3.39
90 Days Ago	1.03	0.83	3.13	3.39

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ALE	Industry	Sector	S&P 500
Current Qtr.	5.20%	0.90%	-27.20%	3.30%
Next Qtr.	20.50%	-7.30%	90.60%	8.10%
This Year	9.00%	5.50%	32.60%	-1.60%
Next Year	3.40%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	6.79%	N/A	N/A	N/A
Next 5 Years (per annum)	5.50%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.67	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.85	13.73	6.72	2.94

Currency in USD.

ALE 0.85%

ALLETE, Inc. (ALE) - NYSE

49.90 0.43(0.85%) 4:02PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	49.47	50.65	49.38	50.49	283,900	50.49
Sep 29, 2015	50.14	50.62	49.24	49.32	252,100	49.32
Sep 28, 2015	50.01	50.50	49.03	50.13	328,600	50.13
Sep 25, 2015	49.46	51.13	49.25	50.20	250,900	50.20
Sep 24, 2015	48.70	49.54	48.37	49.43	181,800	49.43
Sep 23, 2015	48.33	48.78	48.18	48.73	203,400	48.73
Sep 22, 2015	48.15	48.66	47.91	48.22	169,200	48.22
Sep 21, 2015	48.69	48.83	48.36	48.49	111,500	48.49
Sep 18, 2015	48.36	49.15	48.25	48.32	367,500	48.32
Sep 17, 2015	48.39	49.46	48.19	48.83	143,700	48.83
Sep 16, 2015	48.12	48.81	47.84	48.49	119,700	48.49
Sep 15, 2015	48.06	48.15	47.64	48.05	100,900	48.05
Sep 14, 2015	48.17	48.58	47.87	47.98	97,600	47.98
Sep 11, 2015	47.59	48.16	46.76	48.14	160,200	48.14
Sep 10, 2015	47.48	47.98	47.34	47.69	199,700	47.69
Sep 9, 2015	47.62	47.76	47.29	47.46	248,900	47.46
Sep 8, 2015	46.94	47.38	46.26	47.32	191,300	47.32
Sep 4, 2015	46.27	46.51	46.14	46.38	161,900	46.38
Sep 3, 2015	46.74	46.90	45.86	46.67	149,700	46.67
Sep 2, 2015	46.63	46.64	45.99	46.57	271,100	46.57
Sep 1, 2015	47.54	47.54	45.91	46.23	235,400	46.23
Aug 31, 2015	47.62	47.79	46.88	47.78	293,000	47.78
Aug 28, 2015	47.65	48.13	47.12	47.80	146,100	47.80
Aug 27, 2015	47.55	47.79	46.94	47.61	268,300	47.61
Aug 26, 2015	47.60	47.60	46.31	47.41	235,600	47.41
Aug 25, 2015	48.89	49.20	46.61	46.64	301,600	46.64
Aug 24, 2015	48.99	49.99	48.19	48.46	278,900	48.46
Aug 21, 2015	50.29	51.40	49.03	50.65	294,600	50.65
Aug 20, 2015	51.41	52.12	51.27	51.42	175,100	51.42
Aug 19, 2015	51.32	51.84	51.01	51.69	151,100	51.69
Aug 18, 2015	51.71	52.08	51.37	51.55	152,900	51.55
Aug 17, 2015	51.67	52.49	51.36	51.93	207,000	51.93
Aug 14, 2015	51.14	51.72	50.76	51.68	171,400	51.68
Aug 13, 2015	50.92	51.63	50.71	51.17	349,200	51.17
Aug 12, 2015	50.46	51.33	50.22	50.98	207,800	50.98
Aug 12, 2015	0.505 Dividend					
Aug 11, 2015	50.71	51.23	50.36	51.10	288,900	50.59
Aug 10, 2015	51.49	51.49	50.67	50.69	266,800	50.19
Aug 7, 2015	49.93	51.60	49.93	51.21	372,000	50.70
Aug 6, 2015	49.44	50.10	49.10	50.05	229,500	49.56

Aug 5, 2015	49.01	49.93	48.89	49.48	401,800	48.99
Aug 4, 2015	49.98	49.98	48.61	48.80	318,600	48.32
Aug 3, 2015	48.33	48.74	48.06	48.41	209,400	47.93
Jul 31, 2015	48.29	48.65	48.15	48.29	305,000	47.81
Jul 30, 2015	47.75	48.33	47.53	47.93	282,300	47.46
Jul 29, 2015	48.00	48.10	47.67	47.85	243,200	47.38
Jul 28, 2015	47.61	48.07	47.47	48.00	242,200	47.53
Jul 27, 2015	46.16	47.77	46.16	47.53	247,400	47.06
Jul 24, 2015	45.68	46.64	45.54	46.23	563,200	45.77
Jul 23, 2015	46.89	47.07	45.29	45.66	302,900	45.21
Jul 22, 2015	46.67	47.37	46.64	46.94	155,000	46.48
Jul 21, 2015	47.24	47.51	46.53	46.75	159,200	46.29
Jul 20, 2015	47.70	47.92	46.73	47.30	346,500	46.83
Jul 17, 2015	47.97	48.28	47.73	47.77	267,500	47.30
Jul 16, 2015	47.57	48.29	47.57	48.10	399,300	47.62
Jul 15, 2015	47.44	47.51	47.16	47.45	385,100	46.98
Jul 14, 2015	47.78	48.18	47.44	47.50	256,100	47.03
Jul 13, 2015	48.08	48.40	47.75	47.87	176,900	47.40
Jul 10, 2015	47.64	48.40	47.43	48.06	216,700	47.59
Jul 9, 2015	48.43	49.30	47.31	47.54	309,100	47.07
Jul 8, 2015	47.92	48.38	47.92	48.30	355,100	47.82
Jul 7, 2015	47.33	48.32	47.00	48.10	281,000	47.62
Jul 6, 2015	47.14	47.47	46.70	47.30	346,900	46.83
Jul 2, 2015	46.69	47.41	46.65	47.20	225,500	46.73
Jul 1, 2015	46.51	46.53	45.99	46.47	353,700	46.01

* Close price adjusted for dividends and splits.

First | Previous | Next | Last

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Currency in USD.

American Electric Power Co., Inc. (AEP) - NYSE

56.21 0.86(1.51%) 4:04PM EDT

After Hours : **56.21** 0.00 (0.00%) 4:33PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.52	1.16	3.73	3.72
No. of Analysts	13.00	7.00	22.00	22.00
Low Estimate	0.48	1.00	3.62	3.61
High Estimate	0.61	1.27	3.82	3.82
Year Ago EPS	0.48	1.28	3.43	3.73

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	4.09B	4.57B	17.51B	17.34B
No. of Analysts	7	6	13	15
Low Estimate	3.83B	4.04B	16.44B	15.50B
High Estimate	4.47B	4.92B	19.22B	18.84B
Year Ago Sales	4.00B	4.70B	17.00B	17.51B
Sales Growth (year/est)	2.20%	-2.80%	3.00%	-1.00%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.50	1.10	0.81	1.01
EPS Actual	0.48	1.28	0.88	1.06
Difference	-0.02	0.18	0.07	0.05
Surprise %	-4.00%	16.40%	8.60%	5.00%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.52	1.16	3.73	3.72
7 Days Ago	0.49	1.12	3.66	3.73
30 Days Ago	0.51	1.12	3.61	3.74
60 Days Ago	0.50	1.15	3.59	3.71
90 Days Ago	0.51	1.13	3.59	3.71

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	5	2	11	3
Up Last 30 Days	8	2	22	5
Down Last 30 Days	1	2	0	6
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	AEP	Industry	Sector	S&P 500
Current Qtr.	8.30%	0.90%	-27.20%	3.30%
Next Qtr.	-9.40%	-7.30%	90.60%	8.10%
This Year	8.70%	5.50%	32.60%	-1.60%
Next Year	-0.30%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	4.63%	N/A	N/A	N/A
Next 5 Years (per annum)	4.63%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.30	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.30	13.73	6.72	2.94

Currency in USD.

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Thu, Oct 29, 2015, 7:07PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

American Electric Power Co., Inc. (AEP) - NYSE

56.21 0.86(1.51%) 4:04PM EDT

After Hours : **56.21** 0.00 (0.00%) 4:33PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 29 2015

● Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 29, 2015	55.99	56.39	55.74	56.13	2,617,100	56.13
Sep 28, 2015	55.94	56.52	55.46	55.86	2,360,600	55.86
Sep 25, 2015	55.59	56.55	55.19	55.99	2,661,700	55.99
Sep 24, 2015	54.85	55.60	54.74	55.46	3,732,400	55.46
Sep 23, 2015	54.81	55.11	54.51	55.02	1,863,700	55.02
Sep 22, 2015	55.38	55.65	54.60	54.72	3,535,100	54.72
Sep 21, 2015	55.73	55.94	55.35	55.60	2,823,100	55.60
Sep 18, 2015	55.50	56.33	55.34	55.48	3,782,900	55.48
Sep 17, 2015	54.67	56.44	54.54	55.87	5,213,500	55.87
Sep 16, 2015	53.98	54.72	53.84	54.63	4,544,500	54.63
Sep 15, 2015	53.78	54.02	53.39	53.85	2,421,600	53.85
Sep 14, 2015	53.87	54.24	53.60	53.68	2,057,300	53.68
Sep 11, 2015	53.29	53.81	53.04	53.78	1,804,500	53.78
Sep 10, 2015	53.41	53.87	53.18	53.39	2,170,300	53.39
Sep 9, 2015	54.36	54.48	53.27	53.37	2,593,300	53.37
Sep 8, 2015	53.23	54.09	53.23	54.08	3,135,200	54.08
Sep 4, 2015	52.96	53.07	52.29	52.54	2,595,300	52.54
Sep 3, 2015	53.05	53.53	53.00	53.35	2,339,600	53.35
Sep 2, 2015	53.38	53.41	52.46	53.01	2,459,000	53.01
Sep 1, 2015	53.74	53.93	52.65	52.99	3,281,700	52.99
Aug 31, 2015	54.55	54.69	53.82	54.29	3,581,600	54.29
Aug 28, 2015	54.85	55.38	54.07	54.90	2,105,500	54.90
Aug 27, 2015	54.58	54.93	54.11	54.91	2,895,400	54.91
Aug 26, 2015	53.53	54.21	52.80	54.01	4,401,100	54.01
Aug 25, 2015	55.02	55.65	53.00	53.02	4,959,600	53.02
Aug 24, 2015	55.29	56.77	53.03	54.83	5,634,700	54.83
Aug 21, 2015	57.97	58.36	57.22	57.29	3,929,400	57.29
Aug 20, 2015	58.42	59.18	58.12	58.37	1,854,700	58.37
Aug 19, 2015	58.01	58.96	57.82	58.80	2,319,000	58.80
Aug 18, 2015	58.20	58.37	57.96	58.27	1,954,000	58.27
Aug 17, 2015	58.19	58.67	57.99	58.35	2,192,300	58.35
Aug 14, 2015	57.57	58.21	57.09	58.20	1,933,500	58.20
Aug 13, 2015	57.33	57.74	56.88	57.55	1,873,100	57.55
Aug 12, 2015	56.85	57.77	56.60	57.57	2,444,800	57.57
Aug 11, 2015	56.70	57.38	56.46	56.85	2,379,900	56.85
Aug 10, 2015	56.81	57.07	56.54	56.71	2,508,800	56.71
Aug 7, 2015	56.15	57.08	55.78	56.77	2,036,900	56.77
Aug 6, 2015	56.03	56.32	55.34	56.26	2,204,900	56.26
Aug 6, 2015	56.59	56.85	56.24 0.53 Dividend	56.65	2,305,200	56.12

Aug 4, 2015	57.03	57.14	56.28	56.39	2,200,000	55.86
Aug 3, 2015	56.78	57.25	56.65	57.06	2,458,600	56.53
Jul 31, 2015	56.79	57.22	56.48	56.57	2,414,600	56.04
Jul 30, 2015	55.66	56.61	55.57	56.32	1,994,100	55.79
Jul 29, 2015	55.75	56.00	55.38	55.94	2,497,200	55.42
Jul 28, 2015	55.64	56.03	55.52	55.89	2,687,100	55.37
Jul 27, 2015	54.66	56.03	54.62	55.74	2,789,900	55.22
Jul 24, 2015	54.51	54.78	54.17	54.60	3,025,400	54.09
Jul 23, 2015	55.33	55.33	54.22	54.59	3,534,300	54.08
Jul 22, 2015	54.97	55.55	54.89	55.21	3,186,400	54.69
Jul 21, 2015	55.50	55.58	54.65	54.89	2,201,300	54.38
Jul 20, 2015	55.58	55.70	55.05	55.54	2,747,500	55.02
Jul 17, 2015	56.11	56.36	55.71	55.72	2,824,500	55.20
Jul 16, 2015	55.72	56.45	55.62	56.36	2,497,000	55.83
Jul 15, 2015	55.20	55.68	54.99	55.68	2,418,800	55.16
Jul 14, 2015	55.39	55.67	54.99	55.19	1,929,500	54.67
Jul 13, 2015	55.67	55.90	54.88	55.34	2,215,500	54.82
Jul 10, 2015	55.45	55.99	55.21	55.56	2,806,400	55.04
Jul 9, 2015	56.10	56.33	55.23	55.52	3,339,400	55.00
Jul 8, 2015	55.80	56.37	55.75	56.03	2,975,000	55.51
Jul 7, 2015	54.80	56.50	54.74	56.08	4,446,500	55.56
Jul 6, 2015	54.09	54.55	54.02	54.53	3,266,700	54.02
Jul 2, 2015	53.52	54.33	53.51	54.23	2,125,300	53.72
Jul 1, 2015	53.00	53.37	52.76	53.29	2,664,500	52.79

* Close price adjusted for dividends and splits.

First | Previous | Next | Last

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Currency in USD.

Duke Energy Corporation (DUK) - NYSE

71.57 0.02(0.03%) 4:03PM EDT

After Hours : **71.57** 0.00 (0.00%) 5:29PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.52	0.92	4.63	4.86
No. of Analysts	16.00	13.00	21.00	23.00
Low Estimate	1.41	0.79	4.53	4.69
High Estimate	1.63	1.13	4.72	4.95
Year Ago EPS	1.40	0.86	4.55	4.63

Next Earnings Date: Nov 5, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	6.87B	6.28B	24.91B	25.69B
No. of Analysts	7	6	15	17
Low Estimate	6.60B	5.80B	24.10B	24.51B
High Estimate	7.62B	6.98B	25.71B	26.87B
Year Ago Sales	6.40B	5.56B	23.92B	24.91B
Sales Growth (year/est)	7.50%	12.90%	4.10%	3.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.52	0.88	1.14	0.99
EPS Actual	1.40	0.86	1.24	0.95
Difference	-0.12	-0.02	0.10	-0.04
Surprise %	-7.90%	-2.30%	8.80%	-4.00%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.52	0.92	4.63	4.86
7 Days Ago	1.51	0.92	4.64	4.87
30 Days Ago	1.54	0.90	4.64	4.90
60 Days Ago	1.52	0.89	4.63	4.90
90 Days Ago	1.54	0.93	4.67	4.93

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	4	3	0
Down Last 30 Days	1	1	3	3
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	DUK	Industry	Sector	S&P 500
Current Qtr.	8.60%	0.90%	-27.20%	3.30%
Next Qtr.	7.00%	-7.30%	90.60%	8.10%
This Year	1.80%	5.50%	32.60%	-1.60%
Next Year	5.00%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	1.02%	N/A	N/A	N/A
Next 5 Years (per annum)	4.04%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.45	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.82	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 6:26PM EDT - U.S. Markets closed Report an Issue

Dow 0.13% Nasdaq 0.42%

Duke Energy Corporation (DUK) - NYSE

71.57 0.02(0.03%) 4:03PM EDT

After Hours : **71.57** 0.00 (0.00%) 5:29PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
○ Monthly
○ Dividends Only

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	70.95	72.02	70.65	71.94	3,202,100	71.94
Sep 29, 2015	70.44	70.90	70.04	70.73	2,782,500	70.73
Sep 28, 2015	70.59	71.26	70.34	70.45	3,002,400	70.45
Sep 25, 2015	70.31	71.42	69.91	70.71	3,295,700	70.71
Sep 24, 2015	68.87	70.47	68.65	70.32	3,735,500	70.32
Sep 23, 2015	69.18	69.36	68.46	69.09	1,922,600	69.09
Sep 22, 2015	69.58	70.04	68.94	69.15	3,380,300	69.15
Sep 21, 2015	69.30	70.18	69.25	70.05	2,510,900	70.05
Sep 18, 2015	69.25	70.06	69.18	69.45	5,265,100	69.45
Sep 17, 2015	69.23	70.98	69.02	69.91	4,192,900	69.91
Sep 16, 2015	68.92	69.42	68.63	69.18	3,410,400	69.18
Sep 15, 2015	68.36	68.90	67.69	68.59	2,993,200	68.59
Sep 14, 2015	68.40	68.86	68.11	68.31	2,127,800	68.31
Sep 11, 2015	67.64	68.36	67.27	68.34	3,046,100	68.34
Sep 10, 2015	68.20	68.50	67.49	67.74	3,222,600	67.74
Sep 9, 2015	69.63	69.76	68.10	68.21	3,263,100	68.21
Sep 8, 2015	68.80	69.37	68.54	69.36	2,882,800	69.36
Sep 4, 2015	68.70	68.90	67.98	68.26	3,287,700	68.26
Sep 3, 2015	69.54	69.74	69.03	69.28	2,324,700	69.28
Sep 2, 2015	69.68	69.78	68.67	69.16	3,497,900	69.16
Sep 1, 2015	70.26	70.29	68.66	69.05	3,813,100	69.05
Aug 31, 2015	71.84	72.35	70.35	70.91	4,336,000	70.91
Aug 28, 2015	72.60	72.60	71.16	72.39	3,015,900	72.39
Aug 27, 2015	72.23	72.82	71.70	72.52	4,732,000	72.52
Aug 26, 2015	71.22	71.94	70.53	71.74	6,537,400	71.74
Aug 25, 2015	73.27	74.12	70.15	70.21	5,528,100	70.21
Aug 24, 2015	74.66	75.19	72.03	72.44	7,434,200	72.44
Aug 21, 2015	76.15	77.53	75.87	76.71	6,022,900	76.71
Aug 20, 2015	76.78	77.45	76.25	76.77	3,740,000	76.77
Aug 19, 2015	76.10	77.39	75.61	77.21	4,419,200	77.21
Aug 18, 2015	76.39	76.49	76.00	76.24	2,678,300	76.24
Aug 17, 2015	76.45	76.94	76.14	76.52	2,401,600	76.52
Aug 14, 2015	75.37	76.48	75.14	76.37	2,455,800	76.37
Aug 13, 2015	75.38	75.83	74.67	75.58	2,690,600	75.58
Aug 12, 2015	74.40	76.05	74.22	75.56	4,380,600	75.56
Aug 12, 2015			0.825 Dividend			
Aug 11, 2015	75.04	75.88	74.57	75.29	3,431,800	74.46
Aug 10, 2015	75.15	75.41	74.59	74.81	3,594,500	73.99
Aug 6, 2015	73.98	73.98	72.65	73.85	[illegible]	73.03

Aug 5, 2015	74.20	74.49	73.66	73.98	1,979,300	73.17
Aug 4, 2015	74.88	74.88	73.77	73.92	2,413,800	73.11
Aug 3, 2015	74.30	75.08	74.29	74.96	2,754,400	74.14
Jul 31, 2015	74.20	74.93	74.03	74.22	2,761,200	73.41
Jul 30, 2015	72.75	73.68	72.68	73.45	2,479,200	72.65
Jul 29, 2015	72.93	73.27	72.41	73.11	2,797,100	72.31
Jul 28, 2015	72.80	73.38	72.68	73.13	3,242,800	72.33
Jul 27, 2015	71.76	73.31	71.75	73.00	3,104,000	72.20
Jul 24, 2015	71.57	72.02	71.25	71.69	1,817,700	70.90
Jul 23, 2015	72.26	72.31	71.02	71.56	3,358,700	70.78
Jul 22, 2015	72.46	73.02	72.29	72.37	3,316,600	71.58
Jul 21, 2015	73.20	73.20	72.02	72.42	2,939,800	71.63
Jul 20, 2015	73.60	73.78	72.77	73.27	2,897,000	72.47
Jul 17, 2015	74.49	74.74	73.50	73.57	3,779,600	72.76
Jul 16, 2015	74.11	74.99	74.07	74.81	3,137,300	73.99
Jul 15, 2015	73.70	74.15	73.36	74.02	2,521,500	73.21
Jul 14, 2015	74.56	74.81	73.50	73.80	3,372,500	72.99
Jul 13, 2015	74.57	74.94	73.94	74.35	2,796,000	73.54
Jul 10, 2015	74.38	75.17	73.98	74.37	2,381,600	73.56
Jul 9, 2015	74.95	75.23	73.69	74.07	4,500,100	73.26
Jul 8, 2015	74.83	75.57	74.70	74.79	2,918,900	73.97
Jul 7, 2015	73.22	75.71	73.22	75.27	6,836,500	74.45
Jul 6, 2015	72.37	73.00	72.22	72.85	2,830,200	72.05
Jul 2, 2015	71.68	72.64	71.43	72.53	3,377,400	71.74
Jul 1, 2015	70.80	71.12	70.24	71.08	2,372,500	70.30

* Close price adjusted for dividends and splits.

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Look Up

Thu, Oct 29, 2015, 6:35PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

El Paso Electric Co. (EE) - NYSE

38.31 0.49(1.26%) 4:02PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.20	0.10	1.98	2.56
No. of Analysts	3.00	1.00	5.00	5.00
Low Estimate	1.15	0.10	1.95	2.50
High Estimate	1.30	0.10	2.00	2.65
Year Ago EPS	1.30	0.10	2.27	1.98

Next Earnings Date: Nov 4, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	911.04M	938.53M
No. of Analysts			2	2
Low Estimate	NaN	NaN	895.57M	937.26M
High Estimate	NaN	NaN	926.50M	939.80M
Year Ago Sales	NaN	NaN	601.72M	911.04M
Sales Growth (year/est)	N/A	N/A	51.40%	3.00%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.31	0.11	0.12	0.60
EPS Actual	1.30	0.10	0.09	0.52
Difference	-0.01	-0.01	-0.03	-0.08
Surprise %	-0.80%	-9.10%	-25.00%	-13.30%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.20	0.10	1.98	2.56
7 Days Ago	1.20	0.10	1.98	2.56
30 Days Ago	1.23	0.10	1.98	2.56
60 Days Ago	1.23	0.10	1.98	2.56
90 Days Ago	1.23	0.10	2.00	2.58

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EE	Industry	Sector	S&P 500
Current Qtr.	-7.70%	0.90%	-27.20%	3.30%
Next Qtr.	0.00%	-7.30%	90.60%	8.10%
This Year	-12.80%	5.50%	32.60%	-1.60%
Next Year	29.30%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	-11.96%	N/A	N/A	N/A
Next 5 Years (per annum)	7.00%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	19.68	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.81	13.73	6.72	2.94

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Thu, Oct 29, 2015, 6:33PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

EE

El Paso Electric Co. (EE) - NYSE

38.31 **0.49(1.26%)** 4:02PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	36.68	37.00	36.45	36.82	125,700	36.82
Sep 29, 2015	36.52	36.92	36.32	36.48	113,200	36.48
Sep 28, 2015	36.28	36.66	36.17	36.55	113,500	36.55
Sep 25, 2015	36.21	36.83	35.76	36.28	157,500	36.28
Sep 24, 2015	35.39	36.19	35.31	36.11	121,700	36.11
Sep 23, 2015	35.52	35.71	35.15	35.52	159,500	35.52
Sep 22, 2015	35.63	35.94	35.22	35.48	141,600	35.48
Sep 21, 2015	35.52	35.95	35.28	35.81	96,300	35.81
Sep 18, 2015	35.25	35.87	35.05	35.41	262,600	35.41
Sep 17, 2015	34.82	35.95	34.75	35.65	131,100	35.65
Sep 16, 2015	34.69	35.11	34.66	34.96	209,400	34.96
Sep 15, 2015	34.21	34.75	34.17	34.68	114,900	34.68
Sep 14, 2015	34.55	34.70	34.13	34.19	271,700	34.19
Sep 14, 2015			0.295 Dividend			
Sep 11, 2015	34.28	34.73	34.21	34.72	70,700	34.43
Sep 10, 2015	34.64	34.90	34.32	34.37	103,000	34.08
Sep 9, 2015	35.20	35.85	34.60	34.66	119,100	34.37
Sep 8, 2015	34.68	35.14	34.33	35.07	127,700	34.77
Sep 4, 2015	34.18	34.33	33.90	34.20	119,800	33.91
Sep 3, 2015	34.59	35.17	34.29	34.56	188,000	34.27
Sep 2, 2015	34.78	34.78	34.12	34.36	202,400	34.07
Sep 1, 2015	34.98	35.11	34.17	34.45	188,800	34.16
Aug 31, 2015	35.92	35.92	34.95	35.40	176,600	35.10
Aug 28, 2015	35.52	36.03	35.12	35.99	191,700	35.68
Aug 27, 2015	35.49	35.67	34.80	35.61	138,400	35.31
Aug 26, 2015	35.28	35.30	34.51	35.19	134,100	34.89
Aug 25, 2015	36.32	36.34	34.67	34.71	289,200	34.42
Aug 24, 2015	36.09	36.26	35.72	35.81	234,500	35.51
Aug 21, 2015	37.65	37.96	36.91	37.30	224,100	36.98
Aug 20, 2015	37.40	38.08	37.21	37.76	171,200	37.44
Aug 19, 2015	37.47	38.05	36.92	37.74	112,800	37.42
Aug 18, 2015	37.78	38.07	37.67	37.75	128,700	37.43
Aug 17, 2015	37.82	38.32	37.69	38.03	107,200	37.71
Aug 14, 2015	37.22	37.85	37.10	37.82	102,000	37.50
Aug 13, 2015	37.11	37.63	36.85	37.31	219,800	36.99
Aug 12, 2015	36.71	37.31	36.71	37.23	84,600	36.91
Aug 11, 2015	36.37	36.89	36.26	36.86	90,600	36.55
Aug 10, 2015	36.72	36.92	36.35	36.40	112,400	36.09
Aug 7, 2015	36.06	36.81	35.93	36.62	198,200	36.31
Aug 6, 2015	36.31	36.76	35.85	36.29	135,500	35.98

Aug 5, 2015	35.94	36.52	35.94	36.35	157,300	36.04
Aug 4, 2015	36.43	36.43	35.85	35.94	142,300	35.63
Aug 3, 2015	36.41	36.68	36.10	36.47	134,400	36.16
Jul 31, 2015	36.29	36.73	36.16	36.43	238,400	36.12
Jul 30, 2015	35.50	36.31	35.50	36.02	161,600	35.71
Jul 29, 2015	35.59	35.77	35.41	35.65	133,900	35.35
Jul 28, 2015	35.34	35.65	35.06	35.61	113,900	35.31
Jul 27, 2015	34.75	35.37	34.75	35.35	295,700	35.05
Jul 24, 2015	34.63	34.93	34.62	34.72	167,900	34.43
Jul 23, 2015	35.02	35.08	34.43	34.77	234,400	34.47
Jul 22, 2015	35.06	35.75	34.98	35.00	350,000	34.70
Jul 21, 2015	35.54	35.69	35.05	35.19	109,300	34.89
Jul 20, 2015	36.08	36.08	35.48	35.60	256,500	35.30
Jul 17, 2015	36.54	36.54	35.98	36.08	205,700	35.77
Jul 16, 2015	36.01	36.71	35.51	36.65	112,800	36.34
Jul 15, 2015	36.07	36.16	35.65	36.04	147,100	35.73
Jul 14, 2015	36.26	36.35	35.93	36.09	85,700	35.78
Jul 13, 2015	36.46	36.70	35.95	36.30	136,200	35.99
Jul 10, 2015	35.84	36.54	35.77	36.45	137,800	36.14
Jul 9, 2015	35.99	36.12	35.63	35.78	197,000	35.48
Jul 8, 2015	36.10	36.54	35.79	35.98	210,400	35.67
Jul 7, 2015	35.80	36.50	35.48	36.26	213,600	35.95
Jul 6, 2015	35.48	35.91	35.33	35.74	109,300	35.44
Jul 2, 2015	35.15	35.68	35.13	35.67	129,900	35.37
Jul 1, 2015	34.68	35.02	34.41	34.86	130,400	34.56

* Close price adjusted for dividends and splits.

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Currency in USD.

The Empire District Electric Company (EDE) - NYSE

23.41 0.58(2.42%) 4:00PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.59	0.31	1.39	1.51
No. of Analysts	3.00	2.00	4.00	4.00
Low Estimate	0.57	0.29	1.38	1.47
High Estimate	0.60	0.33	1.40	1.55
Year Ago EPS	0.55	0.26	1.55	1.39

Next Earnings Date: Oct 29, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	161.57M	170.94M	653.99M	681.59M
No. of Analysts	1	1	4	4
Low Estimate	161.57M	170.94M	631.43M	655.76M
High Estimate	161.57M	170.94M	676.10M	716.00M
Year Ago Sales	171.51M	151.40M	652.30M	653.99M
Sales Growth (year/est)	-5.80%	12.90%	0.30%	4.20%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.45	0.26	0.34	0.24
EPS Actual	0.55	0.26	0.34	0.15
Difference	0.10	0.00	0.00	-0.09
Surprise %	22.20%	0.00%	0.00%	-37.50%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.59	0.31	1.39	1.51
7 Days Ago	0.59	0.31	1.39	1.51
30 Days Ago	0.55	0.35	1.39	1.51
60 Days Ago	0.55	0.35	1.39	1.51
90 Days Ago	0.52	0.30	1.39	1.51

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	0	1	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	EDE	Industry	Sector	S&P 500
Current Qtr.	7.30%	58.20%	-27.20%	3.30%
Next Qtr.	19.20%	80.90%	90.60%	8.10%
This Year	-10.30%	9.70%	32.60%	-1.60%
Next Year	8.60%	11.50%	22.40%	9.40%
Past 5 Years (per annum)	2.41%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	5.81%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.21	-5.34	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.30	5.67	6.72	2.94

Currency in USD.

Look Up

Thu, Oct 29, 2015, 7:36PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

The Empire District Electric Company (EDE) - NYSE

23.41 0.58(2.42%) 4:00PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

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○ Weekly
○ Monthly
○ Dividends Only

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	21.99	22.13	21.77	22.03	203,300	22.03
Sep 29, 2015	21.97	22.12	21.82	21.90	174,900	21.90
Sep 28, 2015	22.00	22.21	21.88	21.95	184,100	21.95
Sep 25, 2015	22.02	22.31	21.85	22.04	167,300	22.04
Sep 24, 2015	21.62	22.05	21.60	22.03	113,500	22.03
Sep 23, 2015	21.69	21.81	21.61	21.73	117,300	21.73
Sep 22, 2015	21.74	21.99	21.51	21.65	129,700	21.65
Sep 21, 2015	21.78	22.01	21.65	21.84	106,400	21.84
Sep 18, 2015	21.63	21.98	21.61	21.78	255,900	21.78
Sep 17, 2015	21.63	22.13	21.50	21.84	132,400	21.84
Sep 16, 2015	21.46	21.70	21.40	21.67	173,600	21.67
Sep 15, 2015	21.32	21.54	21.13	21.48	160,300	21.48
Sep 14, 2015	21.28	21.46	21.23	21.30	98,400	21.30
Sep 11, 2015	21.05	21.30	20.98	21.28	89,000	21.28
Sep 10, 2015	21.04	21.22	21.02	21.09	166,300	21.09
Sep 9, 2015	21.19	21.45	21.00	21.05	182,300	21.05
Sep 8, 2015	20.99	21.14	20.96	21.13	125,400	21.13
Sep 4, 2015	20.88	21.01	20.69	20.76	146,500	20.76
Sep 3, 2015	20.94	21.17	20.92	21.01	119,300	21.01
Sep 2, 2015	21.18	21.32	20.84	20.92	131,400	20.92
Sep 1, 2015	21.33	21.40	20.92	21.03	232,400	21.03
Aug 31, 2015	21.72	21.72	21.33	21.65	239,900	21.65
Aug 28, 2015	21.80	21.95	21.52	21.78	146,300	21.78
Aug 28, 2015			0.26 Dividend			
Aug 27, 2015	21.91	22.09	21.73	22.02	213,600	21.76
Aug 26, 2015	22.11	22.11	21.55	21.93	240,500	21.67
Aug 25, 2015	22.64	22.67	21.76	21.79	316,400	21.53
Aug 24, 2015	22.64	22.77	22.30	22.31	348,200	22.05
Aug 21, 2015	23.03	23.50	22.92	23.28	222,100	23.01
Aug 20, 2015	23.46	23.81	23.40	23.42	135,500	23.14
Aug 19, 2015	23.58	23.78	23.41	23.65	131,700	23.37
Aug 18, 2015	23.77	23.87	23.58	23.65	142,300	23.37
Aug 17, 2015	23.75	23.99	23.67	23.86	108,400	23.58
Aug 14, 2015	23.53	23.77	23.40	23.77	88,000	23.49
Aug 13, 2015	23.60	23.75	23.44	23.56	144,400	23.28
Aug 12, 2015	23.21	23.72	23.21	23.66	139,600	23.38
Aug 11, 2015	23.08	23.47	22.99	23.38	163,500	23.10
Aug 10, 2015	23.23	23.47	22.99	23.04	204,300	22.77
Aug 7, 2015	23.00	23.55	22.84	23.25	262,500	22.98
Aug 6, 2015	23.05	23.14	22.76	23.08	184,800	22.81

Aug 5, 2015	22.81	23.17	22.80	23.04	160,400	22.77
Aug 4, 2015	23.19	23.19	22.73	22.81	229,000	22.54
Aug 3, 2015	23.07	23.38	23.05	23.17	227,600	22.90
Jul 31, 2015	22.73	23.24	22.66	23.01	272,900	22.74
Jul 30, 2015	22.46	22.68	22.37	22.51	207,200	22.24
Jul 29, 2015	22.34	22.50	22.20	22.46	198,900	22.19
Jul 28, 2015	22.43	22.43	22.15	22.34	253,700	22.08
Jul 27, 2015	21.81	22.43	21.81	22.38	199,300	22.12
Jul 24, 2015	21.70	21.93	21.56	21.84	187,200	21.58
Jul 23, 2015	21.93	22.04	21.52	21.72	345,600	21.46
Jul 22, 2015	21.91	22.17	21.82	22.00	127,800	21.74
Jul 21, 2015	22.15	22.20	21.89	21.96	210,900	21.70
Jul 20, 2015	22.58	22.58	22.16	22.22	153,700	21.96
Jul 17, 2015	22.82	22.82	22.55	22.58	137,700	22.31
Jul 16, 2015	22.58	22.92	22.58	22.85	201,500	22.58
Jul 15, 2015	22.50	22.59	22.31	22.58	109,300	22.31
Jul 14, 2015	22.63	22.70	22.43	22.54	134,700	22.27
Jul 13, 2015	22.69	22.89	22.34	22.63	162,000	22.36
Jul 10, 2015	22.49	22.90	22.47	22.63	287,700	22.36
Jul 9, 2015	22.66	22.69	22.22	22.40	281,400	22.14
Jul 8, 2015	22.62	22.89	22.42	22.56	243,300	22.29
Jul 7, 2015	22.48	22.82	22.44	22.71	297,300	22.44
Jul 6, 2015	22.15	22.40	22.01	22.37	266,700	22.11
Jul 2, 2015	22.16	22.38	22.09	22.19	216,400	21.93
Jul 1, 2015	21.76	22.03	21.68	21.99	263,400	21.73

* Close price adjusted for dividends and splits.

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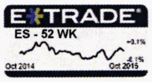

Eversource Energy (ES)- NYSE

50.76 0.21(0.41%) 4:00PM EDT

After Hours : **50.76** 0.00 (0.00%) 5:27PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.77	0.68	2.87	3.03
No. of Analysts	13.00	11.00	16.00	18.00
Low Estimate	0.72	0.62	2.80	2.95
High Estimate	0.80	0.74	2.92	3.11
Year Ago EPS	0.75	0.72	2.75	2.87

Next Earnings Date: Nov 2, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	2.03B	1.72B	8.07B	8.27B
No. of Analysts	6	5	12	12
Low Estimate	1.92B	1.19B	7.62B	7.70B
High Estimate	2.09B	2.01B	8.42B	8.73B
Year Ago Sales	1.89B	1.88B	7.74B	8.07B
Sales Growth (year/est)	7.40%	-8.60%	4.20%	2.50%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.75	0.69	0.80	0.56
EPS Actual	0.75	0.72	0.81	0.66
Difference	0.00	0.03	0.01	0.10
Surprise %	0.00%	4.30%	1.30%	17.90%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.77	0.68	2.87	3.03
7 Days Ago	0.77	0.68	2.87	3.03
30 Days Ago	0.77	0.68	2.87	3.04
60 Days Ago	0.76	0.70	2.86	3.04
90 Days Ago	0.78	0.71	2.86	3.05

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	1	1	0
Up Last 30 Days	1	2	3	1
Down Last 30 Days	1	2	0	2
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	ES	Industry	Sector	S&P 500
Current Qtr.	2.70%	0.90%	-27.20%	3.30%
Next Qtr.	-5.60%	-7.30%	90.60%	8.10%
This Year	4.40%	5.50%	32.60%	-1.60%
Next Year	5.60%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	5.88%	N/A	N/A	N/A
Next 5 Years (per annum)	5.85%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.76	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.04	13.73	6.72	2.94

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Look Up

Thu, Oct 29, 2015, 6:41PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

Eversource Energy (ES) - NYSE

50.76 0.21(0.41%) 4:00PM EDT

After Hours : **50.76** 0.00 (0.00%) 5:27PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily

○ Weekly

○ Monthly

○ Dividends Only

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	49.26	50.66	49.11	50.62	2,548,000	50.62
Sep 29, 2015	49.21	49.77	49.11	49.30	2,489,100	49.30
Sep 28, 2015	48.83	49.20	48.67	49.09	1,996,300	49.09
Sep 25, 2015	48.33	49.37	47.94	48.89	1,730,300	48.89
Sep 24, 2015	47.59	48.24	47.46	48.17	2,264,400	48.17
Sep 23, 2015	47.48	47.88	47.28	47.72	1,617,100	47.72
Sep 22, 2015	47.33	47.68	47.09	47.47	1,604,800	47.47
Sep 21, 2015	47.37	47.66	47.15	47.51	1,441,900	47.51
Sep 18, 2015	47.43	48.08	47.09	47.22	3,555,500	47.22
Sep 17, 2015	46.81	48.33	46.57	47.66	2,969,500	47.66
Sep 16, 2015	46.65	46.93	46.46	46.71	1,929,500	46.71
Sep 15, 2015	46.35	46.82	46.07	46.70	1,764,600	46.70
Sep 14, 2015	46.08	46.47	45.97	46.25	1,129,300	46.25
Sep 11, 2015	45.35	46.09	45.14	46.09	2,064,000	46.09
Sep 10, 2015	45.30	45.91	45.30	45.50	1,707,500	45.50
Sep 10, 2015	0.418 Dividend					
Sep 9, 2015	46.51	46.62	45.78	45.87	1,724,700	45.45
Sep 8, 2015	46.14	46.57	46.07	46.48	1,710,000	46.06
Sep 4, 2015	46.03	46.18	45.63	45.74	1,494,700	45.32
Sep 3, 2015	46.36	46.61	46.17	46.46	2,073,400	46.04
Sep 2, 2015	46.54	46.62	45.88	46.15	2,330,800	45.73
Sep 1, 2015	46.72	46.75	45.83	46.07	2,329,300	45.65
Aug 31, 2015	48.12	48.29	46.89	47.24	2,731,700	46.81
Aug 28, 2015	48.50	48.77	47.54	48.29	1,550,300	47.85
Aug 27, 2015	48.37	48.62	47.87	48.59	1,263,400	48.15
Aug 26, 2015	47.60	48.19	47.06	48.08	1,617,400	47.64
Aug 25, 2015	49.24	49.72	47.21	47.25	2,158,200	46.82
Aug 24, 2015	49.33	50.61	48.68	48.92	3,000,900	48.47
Aug 21, 2015	51.50	51.75	51.01	51.04	1,713,700	50.57
Aug 20, 2015	51.44	52.15	51.30	51.62	1,366,900	51.15
Aug 19, 2015	51.32	51.79	51.02	51.68	1,534,400	51.21
Aug 18, 2015	51.39	51.64	51.17	51.47	1,803,300	51.00
Aug 17, 2015	51.23	51.74	51.12	51.61	1,257,000	51.14
Aug 14, 2015	50.84	51.22	50.54	51.18	885,600	50.71
Aug 13, 2015	50.61	51.03	50.20	50.79	1,413,800	50.33
Aug 12, 2015	50.42	51.15	50.10	50.91	1,289,200	50.45
Aug 11, 2015	50.07	50.68	49.86	50.41	1,189,100	49.95
Aug 10, 2015	49.97	50.18	49.80	50.02	1,834,800	49.56
Aug 6, 2015	49.26	49.62	48.98	49.50	2,542,900	49.08

Aug 5, 2015	49.29	49.55	49.08	49.24	836,600	48.79
Aug 4, 2015	49.83	49.83	49.02	49.10	1,004,300	48.65
Aug 3, 2015	49.77	50.22	49.58	49.85	1,810,000	49.40
Jul 31, 2015	49.57	49.99	49.07	49.72	1,996,100	49.27
Jul 30, 2015	48.13	48.87	48.03	48.77	1,360,800	48.33
Jul 29, 2015	48.10	48.34	47.81	48.29	1,170,600	47.85
Jul 28, 2015	47.87	48.18	47.64	48.12	1,310,500	47.68
Jul 27, 2015	47.27	48.11	47.27	47.87	1,207,300	47.43
Jul 24, 2015	47.29	47.56	47.04	47.21	2,538,800	46.78
Jul 23, 2015	47.82	47.82	46.96	47.35	2,689,100	46.92
Jul 22, 2015	47.64	48.44	47.36	47.83	3,469,100	47.39
Jul 21, 2015	47.58	47.68	46.93	47.52	1,683,300	47.09
Jul 20, 2015	47.85	47.89	47.21	47.58	1,259,900	47.15
Jul 17, 2015	48.30	48.49	47.85	47.92	1,246,800	47.48
Jul 16, 2015	47.68	48.40	47.58	48.30	1,080,400	47.86
Jul 15, 2015	47.30	47.86	47.07	47.72	1,946,800	47.29
Jul 14, 2015	47.04	47.35	46.89	47.30	1,322,000	46.87
Jul 13, 2015	47.15	47.39	46.81	47.04	1,331,700	46.61
Jul 10, 2015	46.74	47.37	46.54	46.89	1,830,700	46.46
Jul 9, 2015	47.25	47.35	46.24	46.73	2,986,100	46.30
Jul 8, 2015	47.28	47.77	46.89	47.13	3,002,700	46.70
Jul 7, 2015	46.55	47.75	46.53	47.38	3,802,800	46.95
Jul 6, 2015	44.88	46.55	44.64	46.31	7,597,500	45.89
Jul 2, 2015	45.97	46.56	45.79	46.51	1,839,700	46.09
Jul 1, 2015	45.53	45.73	45.34	45.57	1,798,900	45.15

* Close price adjusted for dividends and splits.

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Thu, Oct 29, 2015, 7:18PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

Great Plains Energy Incorporated (GXP) - NYSE

27.41 0.23(0.83%) 4:03PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.88	0.19	1.49	1.81
No. of Analysts	9.00	6.00	12.00	12.00
Low Estimate	0.83	0.15	1.42	1.75
High Estimate	0.90	0.22	1.54	1.90
Year Ago EPS	0.95	0.12	1.57	1.49

Next Earnings Date: Nov 5, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	796.85M	638.28M	2.58B	2.71B
No. of Analysts	4	4	9	9
Low Estimate	771.40M	562.70M	2.48B	2.56B
High Estimate	823.00M	723.27M	2.66B	2.77B
Year Ago Sales	782.50M	552.20M	2.57B	2.58B
Sales Growth (year/est)	1.80%	15.60%	0.30%	5.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.97	0.13	0.11	0.30
EPS Actual	0.95	0.12	0.12	0.28
Difference	-0.02	-0.01	0.01	-0.02
Surprise %	-2.10%	-7.70%	9.10%	-6.70%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.88	0.19	1.49	1.81
7 Days Ago	0.88	0.19	1.49	1.81
30 Days Ago	0.89	0.18	1.50	1.82
60 Days Ago	0.93	0.15	1.50	1.82
90 Days Ago	0.94	0.13	1.51	1.83

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 30 Days	1	1	2	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	GXP	Industry	Sector	S&P 500
Current Qtr.	-7.40%	0.90%	-27.20%	3.30%
Next Qtr.	58.30%	-7.30%	90.60%	8.10%
This Year	-5.10%	5.50%	32.60%	-1.60%
Next Year	21.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	8.93%	N/A	N/A	N/A
Next 5 Years (per annum)	6.37%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.81	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.95	13.73	6.72	2.94

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Thu, Oct 29, 2015, 7:18PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

Great Plains Energy Incorporated (GXP) - NYSE

27.41 0.23(0.83%) 4:03PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
○ Monthly
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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	26.63	27.08	26.34	27.02	2,084,200	27.02
Sep 29, 2015	26.32	26.52	26.22	26.49	1,893,600	26.49
Sep 28, 2015	26.16	26.43	26.08	26.28	1,342,900	26.28
Sep 25, 2015	26.05	26.58	25.86	26.25	1,388,500	26.25
Sep 24, 2015	25.66	26.04	25.66	25.99	895,900	25.99
Sep 23, 2015	25.49	25.87	25.45	25.76	1,085,900	25.76
Sep 22, 2015	25.52	25.68	25.22	25.51	1,297,100	25.51
Sep 21, 2015	25.76	25.97	25.60	25.67	1,531,300	25.67
Sep 18, 2015	25.29	25.95	25.29	25.66	1,817,400	25.66
Sep 17, 2015	25.38	26.04	25.01	25.72	1,386,600	25.72
Sep 16, 2015	25.13	25.40	25.00	25.36	1,242,400	25.36
Sep 15, 2015	25.00	25.15	24.77	25.05	1,200,200	25.05
Sep 14, 2015	24.99	25.18	24.91	24.96	1,045,900	24.96
Sep 11, 2015	24.49	24.93	24.40	24.91	851,100	24.91
Sep 10, 2015	24.54	24.96	24.52	24.60	1,461,200	24.60
Sep 9, 2015	24.88	24.95	24.51	24.56	1,254,500	24.56
Sep 8, 2015	24.49	24.84	24.34	24.77	1,702,800	24.77
Sep 4, 2015	24.43	24.49	24.08	24.21	1,171,800	24.21
Sep 3, 2015	24.36	24.71	24.29	24.66	1,713,400	24.66
Sep 2, 2015	24.53	24.58	24.16	24.30	1,315,300	24.30
Sep 1, 2015	24.54	24.68	24.15	24.28	1,201,200	24.28
Aug 31, 2015	25.08	25.18	24.63	24.92	1,238,700	24.92
Aug 28, 2015	25.18	25.45	25.02	25.27	949,000	25.27
Aug 27, 2015	25.06	25.36	24.90	25.35	1,402,600	25.35
Aug 26, 2015	24.96	24.99	24.30	24.90	2,186,400	24.90
Aug 26, 2015			0.245 Dividend			
Aug 25, 2015	25.79	25.80	24.69	24.72	2,333,200	24.47
Aug 24, 2015	25.74	26.09	25.23	25.39	2,808,600	25.14
Aug 21, 2015	26.86	26.98	26.49	26.50	2,078,500	26.24
Aug 20, 2015	27.02	27.33	26.92	27.01	891,900	26.74
Aug 19, 2015	27.01	27.33	26.86	27.22	1,026,700	26.95
Aug 18, 2015	27.22	27.38	27.13	27.15	622,600	26.88
Aug 17, 2015	27.16	27.46	27.01	27.35	765,200	27.08
Aug 14, 2015	26.80	27.22	26.73	27.15	743,600	26.88
Aug 13, 2015	26.83	26.98	26.58	26.88	859,900	26.61
Aug 12, 2015	26.38	26.99	26.38	26.93	1,367,500	26.66
Aug 11, 2015	26.28	26.67	26.04	26.52	1,507,700	26.26
Aug 10, 2015	26.40	26.71	26.18	26.23	1,367,500	25.97
Aug 7, 2015	25.86	26.73	25.86	26.42	1,635,400	26.16
Aug 6, 2015	26.17	26.19	25.70	25.89	1,822,600	25.63

Aug 5, 2015	25.99	26.23	25.87	26.12	985,100	25.86
Aug 4, 2015	26.17	26.31	25.79	25.85	819,000	25.59
Aug 3, 2015	26.20	26.40	26.00	26.17	779,300	25.91
Jul 31, 2015	26.14	26.32	25.88	26.11	686,500	25.85
Jul 30, 2015	25.63	26.03	25.48	25.83	1,013,200	25.57
Jul 29, 2015	25.39	25.71	25.28	25.70	958,500	25.45
Jul 28, 2015	25.21	25.46	25.01	25.44	1,288,200	25.19
Jul 27, 2015	24.73	25.29	24.69	25.19	796,800	24.94
Jul 24, 2015	24.74	24.85	24.62	24.74	795,900	24.49
Jul 23, 2015	24.88	24.89	24.53	24.73	1,248,100	24.48
Jul 22, 2015	24.89	25.12	24.85	24.96	782,200	24.71
Jul 21, 2015	25.24	25.30	24.82	24.83	1,127,400	24.58
Jul 20, 2015	25.47	25.47	25.13	25.29	576,200	25.04
Jul 17, 2015	25.66	25.74	25.46	25.49	1,122,100	25.24
Jul 16, 2015	25.30	25.75	25.18	25.73	1,231,700	25.47
Jul 15, 2015	25.10	25.18	24.92	25.18	1,163,000	24.93
Jul 14, 2015	25.22	25.34	25.06	25.10	1,040,200	24.85
Jul 13, 2015	25.40	25.52	25.08	25.20	1,398,400	24.95
Jul 10, 2015	25.05	25.40	24.81	25.30	2,452,900	25.05
Jul 9, 2015	25.45	25.48	24.79	24.83	2,698,000	24.58
Jul 8, 2015	25.58	25.68	25.33	25.38	1,213,000	25.13
Jul 7, 2015	25.07	25.72	25.04	25.61	1,374,200	25.36
Jul 6, 2015	24.83	25.01	24.63	25.01	845,700	24.76
Jul 2, 2015	24.74	24.95	24.61	24.78	762,300	24.53
Jul 1, 2015	24.24	24.55	24.13	24.51	1,550,900	24.27

* Close price adjusted for dividends and splits.

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Thu, Oct 29, 2015, 6:46PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

IdaCorp, Inc. (IDA) - NYSE

66.44 1.68(2.47%) 4:00PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.54	0.54	3.86	3.87
No. of Analysts	3.00	2.00	3.00	3.00
Low Estimate	1.44	0.45	3.84	3.80
High Estimate	1.67	0.63	3.90	3.92
Year Ago EPS	1.73	0.69	3.85	3.86

Next Earnings Date: Oct 29, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	NaN	NaN	1.27B	1.28B
No. of Analysts			2	2
Low Estimate	NaN	NaN	1.25B	1.26B
High Estimate	NaN	NaN	1.29B	1.30B
Year Ago Sales	NaN	NaN	1.28B	1.27B
Sales Growth (year/est)	N/A	N/A	-1.30%	1.40%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.57	0.58	0.58	1.07
EPS Actual	1.73	0.69	0.47	1.31
Difference	0.16	0.11	-0.11	0.24
Surprise %	10.20%	19.00%	-19.00%	22.40%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.54	0.54	3.86	3.87
7 Days Ago	1.54	0.54	3.86	3.87
30 Days Ago	1.61	0.45	3.86	3.87
60 Days Ago	1.61	0.45	3.86	3.87
90 Days Ago	1.65	0.49	3.81	3.87

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 30 Days	1	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	IDA	Industry	Sector	S&P 500
Current Qtr.	-11.00%	0.90%	-27.20%	3.30%
Next Qtr.	-21.70%	-7.30%	90.60%	8.10%
This Year	0.30%	5.50%	32.60%	-1.60%
Next Year	0.30%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	8.15%	N/A	N/A	N/A
Next 5 Years (per annum)	4.00%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.13	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.53	13.73	6.72	2.94

Currency in USD.

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Thu, Oct 29, 2015, 6:45PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

IDA
2.47%

IdaCorp, Inc. (IDA) - NYSE

66.44 **1.68(2.47%)** 4:00PM EDT

Historical Prices

Get Historical Prices for: GO

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Start Date: Jul 1 2015 Eg. Jan 1, 2010
End Date: Sep 30 2015

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	63.81	64.85	63.50	64.71	306,200	64.71
Sep 29, 2015	63.71	64.15	63.37	63.71	243,700	63.71
Sep 28, 2015	63.59	64.13	63.44	63.62	276,400	63.62
Sep 25, 2015	63.35	64.94	63.13	63.63	366,000	63.63
Sep 24, 2015	61.50	63.38	61.50	63.25	346,800	63.25
Sep 23, 2015	61.40	61.83	60.85	61.70	196,400	61.70
Sep 22, 2015	61.15	61.72	60.95	61.23	212,000	61.23
Sep 21, 2015	61.59	62.11	61.32	61.42	197,500	61.42
Sep 18, 2015	60.35	61.65	60.24	61.35	819,800	61.35
Sep 17, 2015	59.92	61.42	59.59	60.75	188,000	60.75
Sep 16, 2015	58.96	60.11	58.88	60.01	286,400	60.01
Sep 15, 2015	58.90	59.22	58.69	58.75	390,500	58.75
Sep 14, 2015	59.03	59.35	58.75	59.00	130,100	59.00
Sep 11, 2015	57.81	58.71	57.69	58.70	153,800	58.70
Sep 10, 2015	58.24	58.74	57.83	57.99	188,700	57.99
Sep 9, 2015	58.88	59.57	58.24	58.28	207,200	58.28
Sep 8, 2015	58.23	58.94	58.13	58.79	298,800	58.79
Sep 4, 2015	57.42	57.85	57.23	57.60	231,900	57.60
Sep 3, 2015	58.08	58.31	57.81	58.05	167,300	58.05
Sep 2, 2015	58.17	58.43	57.35	57.78	176,900	57.78
Sep 1, 2015	58.50	58.79	57.35	57.61	227,200	57.61
Aug 31, 2015	60.01	60.50	58.68	59.37	230,300	59.37
Aug 28, 2015	60.52	60.61	59.43	60.19	174,100	60.19
Aug 27, 2015	60.08	60.51	59.55	60.47	220,000	60.47
Aug 26, 2015	59.79	59.98	58.31	59.80	284,600	59.80
Aug 25, 2015	61.97	61.97	58.78	58.84	366,500	58.84
Aug 24, 2015	61.42	61.80	60.34	60.58	529,300	60.58
Aug 21, 2015	62.82	63.86	62.49	63.17	445,800	63.17
Aug 20, 2015	63.55	64.42	63.26	63.71	268,900	63.71
Aug 19, 2015	63.56	64.23	63.11	63.96	227,200	63.96
Aug 18, 2015	64.06	64.32	63.60	63.89	158,800	63.89
Aug 17, 2015	63.67	64.52	63.59	64.37	232,900	64.37
Aug 14, 2015	63.25	63.82	62.94	63.69	176,600	63.69
Aug 13, 2015	62.96	63.64	62.50	63.33	155,800	63.33
Aug 12, 2015	62.30	63.17	62.30	63.07	179,100	63.07
Aug 11, 2015	61.77	62.73	61.68	62.46	131,900	62.46
Aug 10, 2015	61.96	62.41	61.76	61.92	323,500	61.92
Aug 7, 2015	60.70	62.11	60.63	61.90	276,500	61.90
Aug 6, 2015	60.97	61.21	60.38	61.02	232,600	61.02
Aug 5, 2015	60.90	61.43	60.14	60.98	207,400	60.98

Aug 4, 2015	61.81	61.81	60.49	60.61	285,300	60.61
Aug 3, 2015	61.85	62.33	61.17	61.75	270,100	61.75
Aug 3, 2015			0.47 Dividend			
Jul 31, 2015	62.01	62.63	61.53	62.11	257,400	61.64
Jul 30, 2015	60.46	62.20	60.10	61.32	735,700	60.86
Jul 29, 2015	59.42	60.57	59.08	60.46	379,800	60.00
Jul 28, 2015	59.18	59.74	58.86	59.68	242,200	59.23
Jul 27, 2015	57.97	59.20	57.97	59.18	180,800	58.73
Jul 24, 2015	57.91	58.49	57.86	58.08	298,100	57.64
Jul 23, 2015	58.43	58.72	57.47	58.13	407,100	57.69
Jul 22, 2015	57.95	58.98	57.95	58.63	244,300	58.19
Jul 21, 2015	58.27	58.61	57.72	57.88	246,700	57.44
Jul 20, 2015	58.37	58.45	57.83	58.13	149,300	57.69
Jul 17, 2015	58.83	59.21	58.43	58.50	167,300	58.06
Jul 16, 2015	58.16	59.09	58.16	59.00	174,600	58.55
Jul 15, 2015	57.94	58.20	57.45	58.20	120,100	57.76
Jul 14, 2015	58.20	58.43	57.79	57.99	150,700	57.55
Jul 13, 2015	58.06	58.60	57.94	58.14	248,700	57.70
Jul 10, 2015	57.50	58.53	57.35	58.07	316,500	57.63
Jul 9, 2015	58.94	59.10	57.34	57.55	373,100	57.11
Jul 8, 2015	58.98	59.49	58.69	58.94	238,100	58.49
Jul 7, 2015	58.20	59.40	58.00	59.21	219,000	58.76
Jul 6, 2015	57.12	57.93	56.49	57.83	247,500	57.39
Jul 2, 2015	57.03	57.49	56.71	57.34	186,000	56.91
Jul 1, 2015	56.26	56.62	55.96	56.59	207,600	56.16

* Close price adjusted for dividends and splits.

First | Previous | Next | Last

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Look Up

Thu, Oct 29, 2015, 6:48PM EDT - U.S. Markets closed Report an Issue

Dow 0.13%

Otter Tail Corporation (OTTR) - NasdaqGS

27.78 0.16(0.57%) 4:00PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.44	0.47	1.63	1.72
No. of Analysts	2.00	2.00	2.00	2.00
Low Estimate	0.43	0.43	1.60	1.70
High Estimate	0.44	0.50	1.66	1.74
Year Ago EPS	0.43	0.38	1.55	1.63

Next Earnings Date: Nov 2, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	202.65M	198.95M	792.65M	830.95M
No. of Analysts	2	2	2	2
Low Estimate	198.50M	198.20M	787.80M	822.90M
High Estimate	206.80M	199.70M	797.50M	839.00M
Year Ago Sales	242.37M	193.41M	799.26M	792.65M
Sales Growth (year/est)	-16.40%	2.90%	-0.80%	4.80%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.41	0.45	0.55	0.23
EPS Actual	0.43	0.38	0.37	0.36
Difference	0.02	-0.07	-0.18	0.13
Surprise %	4.90%	-15.60%	-32.70%	56.50%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.44	0.47	1.63	1.72
7 Days Ago	0.44	0.47	1.63	1.72
30 Days Ago	0.42	0.47	1.62	1.72
60 Days Ago	0.42	0.47	1.62	1.72
90 Days Ago	0.41	0.56	1.56	1.75

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	0	1	0
Up Last 30 Days	1	0	1	0
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	OTTR	Industry	Sector	S&P 500
Current Qtr.	2.30%	0.90%	-27.20%	3.30%
Next Qtr.	23.70%	-7.30%	90.60%	8.10%
This Year	5.20%	5.50%	32.60%	-1.60%
Next Year	5.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	44.19%	N/A	N/A	N/A
Next 5 Years (per annum)	6.00%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.52	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.92	13.73	6.72	2.94

Currency in USD.

OTTR
0.57%

Otter Tail Corporation (OTTR) - NasdaqGS

27.78 0.16(0.57%) 4:00PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	25.97	26.17	25.74	26.06	73,900	26.06
Sep 29, 2015	26.08	26.23	25.80	25.84	52,700	25.84
Sep 28, 2015	26.03	26.34	25.94	26.10	124,900	26.10
Sep 25, 2015	26.14	26.60	26.01	26.17	94,900	26.17
Sep 24, 2015	25.49	26.08	25.49	26.02	52,600	26.02
Sep 23, 2015	25.34	25.67	25.31	25.60	58,300	25.60
Sep 22, 2015	25.55	25.69	25.32	25.42	63,300	25.42
Sep 21, 2015	26.01	26.12	25.67	25.85	48,300	25.85
Sep 18, 2015	25.51	26.11	25.51	25.88	149,800	25.88
Sep 17, 2015	25.79	26.36	25.70	25.92	73,500	25.92
Sep 16, 2015	25.56	25.99	25.56	25.83	56,300	25.83
Sep 15, 2015	25.39	25.62	25.20	25.51	53,300	25.51
Sep 14, 2015	25.68	25.68	25.22	25.29	41,500	25.29
Sep 11, 2015	25.37	25.56	25.20	25.51	72,100	25.51
Sep 10, 2015	25.51	25.82	25.46	25.54	69,700	25.54
Sep 9, 2015	25.98	25.98	25.42	25.46	93,000	25.46
Sep 8, 2015	25.64	25.96	25.57	25.83	59,700	25.83
Sep 4, 2015	25.29	25.67	25.05	25.30	98,700	25.30
Sep 3, 2015	25.45	25.73	25.24	25.43	78,700	25.43
Sep 2, 2015	25.45	25.58	25.26	25.41	80,000	25.41
Sep 1, 2015	25.42	25.58	25.18	25.22	101,000	25.22
Aug 31, 2015	25.75	25.89	25.31	25.81	88,500	25.81
Aug 28, 2015	25.52	25.84	25.27	25.82	101,600	25.82
Aug 27, 2015	25.88	26.21	25.41	25.68	88,500	25.68
Aug 26, 2015	25.38	25.82	25.09	25.77	83,000	25.77
Aug 25, 2015	26.33	26.36	24.90	24.90	129,600	24.90
Aug 24, 2015	25.62	26.67	25.51	25.53	127,600	25.53
Aug 21, 2015	26.50	27.20	26.43	26.70	135,800	26.70
Aug 20, 2015	27.08	27.53	26.94	26.98	91,400	26.98
Aug 19, 2015	27.14	27.47	26.65	27.27	79,100	27.27
Aug 18, 2015	27.63	27.67	27.23	27.32	72,100	27.32
Aug 17, 2015	27.65	27.85	27.52	27.76	68,900	27.76
Aug 14, 2015	27.46	27.82	27.08	27.82	98,400	27.82
Aug 13, 2015	27.88	27.96	27.49	27.59	90,300	27.59
Aug 12, 2015	27.82	28.04	27.69	27.95	70,000	27.95
Aug 12, 2015	0.308 Dividend					
Aug 11, 2015	27.81	28.22	27.70	28.19	66,700	27.88
Aug 10, 2015	27.92	28.24	27.81	27.98	102,600	27.67
Aug 7, 2015	27.78	28.20	27.75	27.86	120,300	27.56
Aug 6, 2015	27.91	28.08	27.55	28.01	66,800	27.70

Aug 5, 2015	28.01	28.23	27.72	27.80	88,400	27.50
Aug 4, 2015	26.20	28.34	25.95	27.99	183,500	27.68
Aug 3, 2015	26.00	26.06	25.28	25.75	105,200	25.47
Jul 31, 2015	25.76	26.24	25.73	25.92	87,100	25.64
Jul 30, 2015	25.69	26.13	25.66	25.82	52,500	25.54
Jul 29, 2015	25.64	25.88	25.58	25.81	51,200	25.53
Jul 28, 2015	25.95	26.35	25.65	25.76	74,800	25.48
Jul 27, 2015	24.90	26.00	24.82	25.89	92,900	25.61
Jul 24, 2015	25.56	25.89	25.35	25.40	110,000	25.12
Jul 23, 2015	26.39	26.39	25.55	25.66	71,600	25.38
Jul 22, 2015	26.43	26.67	26.24	26.30	49,600	26.01
Jul 21, 2015	26.60	26.92	26.33	26.44	59,000	26.15
Jul 20, 2015	27.12	27.29	26.61	26.74	58,300	26.45
Jul 17, 2015	27.45	27.45	27.05	27.06	53,400	26.76
Jul 16, 2015	27.24	27.62	27.24	27.38	52,500	27.08
Jul 15, 2015	27.20	27.28	27.04	27.19	45,800	26.89
Jul 14, 2015	27.14	27.36	27.04	27.16	47,900	26.86
Jul 13, 2015	27.19	27.46	27.04	27.22	60,300	26.92
Jul 10, 2015	26.90	27.28	26.90	27.13	67,200	26.83
Jul 9, 2015	27.24	27.27	26.65	26.76	68,500	26.47
Jul 8, 2015	27.12	27.45	26.93	27.05	58,700	26.75
Jul 7, 2015	27.13	27.47	27.01	27.36	67,700	27.06
Jul 6, 2015	26.77	27.17	26.68	27.05	93,500	26.75
Jul 2, 2015	26.87	27.19	26.77	27.04	61,200	26.74
Jul 1, 2015	26.66	26.76	26.50	26.73	96,400	26.44

* Close price adjusted for dividends and splits.

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Look Up

Thu, Oct 29, 2015, 6:55PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

Pinnacle West Capital Corporation (PNW) - NYSE

63.17 0.69(1.07%) 4:01PM EDT

After Hours : **63.17** 0.00 (0.00%) 5:27PM EDT

Analyst Estimates

Get Analyst Estimates for: GC

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	2.32	0.22	3.82	4.02
No. of Analysts	13.00	10.00	17.00	18.00
Low Estimate	2.28	0.15	3.76	3.94
High Estimate	2.40	0.27	3.86	4.10
Year Ago EPS	2.20	0.05	3.58	3.82

Next Earnings Date: Oct 30, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.20B	762.30M	3.54B	3.64B
No. of Analysts	6	6	12	14
Low Estimate	1.16B	739.26M	3.44B	3.53B
High Estimate	1.24B	775.07M	3.62B	3.85B
Year Ago Sales	1.17B	726.45M	3.49B	3.54B
Sales Growth (year/est)	2.10%	4.90%	1.30%	3.00%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	2.14	0.18	0.18	1.23
EPS Actual	2.20	0.05	0.14	1.10
Difference	0.06	-0.13	-0.04	-0.13
Surprise %	2.80%	-72.20%	-22.20%	-10.60%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	2.32	0.22	3.82	4.02
7 Days Ago	2.32	0.22	3.82	4.02
30 Days Ago	2.31	0.24	3.83	4.02
60 Days Ago	2.31	0.24	3.83	4.02
90 Days Ago	2.31	0.23	3.83	4.02

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	2	0	0	0
Up Last 30 Days	3	0	0	0
Down Last 30 Days	1	3	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNW	Industry	Sector	S&P 500
Current Qtr.	5.50%	0.90%	-27.20%	3.30%
Next Qtr.	340.00%	-7.30%	90.60%	8.10%
This Year	6.70%	5.50%	32.60%	-1.60%
Next Year	5.20%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	-10.44%	N/A	N/A	N/A
Next 5 Years (per annum)	5.37%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	16.88	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	3.14	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 6:54PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

PNW

Pinnacle West Capital Corporation (PNW) - NYSE

63.17 0.69(1.07%) 4:01PM EDT

After Hours : **63.17** 0.00 (0.00%) 5:27PM EDT

Historical Prices

Get Historical Prices for: GC

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	63.52	64.21	63.23	64.14	564,200	64.14
Sep 29, 2015	63.26	63.62	62.75	63.22	760,000	63.22
Sep 28, 2015	63.51	63.86	62.99	63.17	665,100	63.17
Sep 25, 2015	62.69	64.09	62.52	63.52	620,500	63.52
Sep 24, 2015	62.06	62.82	61.60	62.63	970,600	62.63
Sep 23, 2015	62.24	62.54	61.86	62.23	576,500	62.23
Sep 22, 2015	61.54	62.41	61.54	62.20	791,100	62.20
Sep 21, 2015	61.97	62.77	61.65	62.29	1,218,700	62.29
Sep 18, 2015	61.27	62.33	61.20	61.77	1,281,500	61.77
Sep 17, 2015	61.00	62.47	60.94	61.77	543,900	61.77
Sep 16, 2015	60.21	61.23	59.92	61.09	759,800	61.09
Sep 15, 2015	59.88	60.29	59.55	60.18	772,200	60.18
Sep 14, 2015	59.87	60.29	59.68	59.88	816,200	59.88
Sep 11, 2015	58.74	59.80	58.61	59.79	861,100	59.79
Sep 10, 2015	59.15	59.69	58.88	59.06	962,600	59.06
Sep 9, 2015	59.88	59.95	59.00	59.23	1,244,700	59.23
Sep 8, 2015	58.22	59.75	57.99	59.68	1,656,400	59.68
Sep 4, 2015	57.66	58.01	57.33	57.60	668,200	57.60
Sep 3, 2015	58.16	58.68	58.02	58.27	717,300	58.27
Sep 2, 2015	58.63	58.73	57.57	58.01	659,000	58.01
Sep 1, 2015	59.02	59.02	57.78	58.01	865,600	58.01
Aug 31, 2015	60.15	60.39	58.95	59.53	1,099,800	59.53
Aug 28, 2015	60.66	60.84	59.81	60.48	1,492,100	60.48
Aug 27, 2015	60.78	60.80	59.90	60.78	1,312,300	60.78
Aug 26, 2015	60.34	60.54	59.24	60.33	1,354,900	60.33
Aug 25, 2015	62.35	62.85	59.55	59.61	1,209,900	59.61
Aug 24, 2015	62.16	62.36	60.97	61.69	2,531,600	61.69
Aug 21, 2015	64.10	64.40	63.25	63.27	945,200	63.27
Aug 20, 2015	64.17	65.23	63.92	64.34	977,000	64.34
Aug 19, 2015	64.08	64.90	63.85	64.59	628,700	64.59
Aug 18, 2015	64.77	64.77	64.28	64.38	627,300	64.38
Aug 17, 2015	64.43	65.12	64.07	64.85	595,100	64.85
Aug 14, 2015	63.69	64.48	63.32	64.37	646,500	64.37
Aug 13, 2015	63.50	64.07	62.94	63.86	521,600	63.86
Aug 12, 2015	62.88	63.95	62.63	63.77	766,500	63.77
Aug 11, 2015	62.26	63.27	62.08	63.08	730,700	63.08
Aug 10, 2015	62.70	62.99	62.16	62.25	627,700	62.25
Aug 7, 2015	61.39	62.89	61.02	62.62	904,500	62.62
Aug 6, 2015	60.80	61.29	60.62	60.85	676,300	60.85

Aug 4, 2015	61.88	61.88	60.70	60.80	677,400	60.80
Aug 3, 2015	61.72	62.36	61.61	61.92	723,000	61.92
Jul 31, 2015	61.57	62.63	61.57	61.71	616,200	61.71
Jul 30, 2015	60.31	62.23	59.55	61.27	1,275,700	61.27
Jul 30, 2015	0.595 Dividend					
Jul 29, 2015	60.90	61.56	60.59	61.52	857,900	60.93
Jul 28, 2015	60.88	61.25	60.71	61.09	1,076,100	60.50
Jul 27, 2015	59.87	61.04	59.87	60.97	1,313,400	60.38
Jul 24, 2015	59.60	60.29	59.42	59.99	658,700	59.41
Jul 23, 2015	60.26	60.26	59.16	59.69	749,600	59.11
Jul 22, 2015	59.95	60.54	59.82	60.34	936,500	59.76
Jul 21, 2015	60.56	60.76	59.52	59.96	1,010,100	59.38
Jul 20, 2015	60.63	61.12	60.25	60.81	1,479,600	60.22
Jul 17, 2015	60.99	61.03	60.37	60.42	817,400	59.84
Jul 16, 2015	60.20	61.28	60.20	61.17	1,185,600	60.58
Jul 15, 2015	60.04	60.24	59.39	60.21	919,200	59.63
Jul 14, 2015	60.17	60.55	59.87	60.11	896,900	59.53
Jul 13, 2015	60.52	60.81	59.78	60.18	849,700	59.60
Jul 10, 2015	59.60	60.68	59.37	60.32	1,203,600	59.74
Jul 9, 2015	60.44	60.72	59.43	59.68	1,039,000	59.10
Jul 8, 2015	60.10	60.49	60.02	60.28	1,196,900	59.70
Jul 7, 2015	58.78	60.53	58.71	60.34	1,148,200	59.76
Jul 6, 2015	58.16	58.60	57.82	58.49	758,100	57.92
Jul 2, 2015	57.93	58.55	57.24	58.32	944,100	57.76
Jul 1, 2015	57.03	57.67	56.77	57.58	1,156,400	57.02

* Close price adjusted for dividends and splits.

First | Previous | Next | Last

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Currency in USD.

Thu, Oct 29, 2015, 6:57PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13%

PNM Resources, Inc. (PNM) - NYSE

27.62 0.58(2.06%) 4:02PM EDT

After Hours : **27.62** 0.00 (0.00%) 4:33PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.74	0.19	1.57	1.64
No. of Analysts	6.00	4.00	9.00	9.00
Low Estimate	0.68	0.13	1.55	1.60
High Estimate	0.77	0.24	1.60	1.70
Year Ago EPS	0.68	0.24	1.49	1.57

Next Earnings Date: Oct 30, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	453.50M	336.50M	1.46B	1.52B
No. of Analysts	2	2	5	5
Low Estimate	417.00M	309.00M	1.43B	1.48B
High Estimate	490.00M	364.00M	1.48B	1.54B
Year Ago Sales	413.95M	346.84M	1.44B	1.46B
Sales Growth (year/est)	9.60%	-3.00%	1.40%	4.20%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	0.66	0.23	0.18	0.41
EPS Actual	0.68	0.24	0.21	0.44
Difference	0.02	0.01	0.03	0.03
Surprise %	3.00%	4.30%	16.70%	7.30%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.74	0.19	1.57	1.64
7 Days Ago	0.74	0.19	1.57	1.64
30 Days Ago	0.71	0.20	1.56	1.64
60 Days Ago	0.71	0.20	1.56	1.64
90 Days Ago	0.75	0.19	1.56	1.65

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	0	0	1	1
Up Last 30 Days	0	0	1	1
Down Last 30 Days	0	0	0	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	PNM	Industry	Sector	S&P 500
Current Qtr.	8.80%	0.90%	-27.20%	3.30%
Next Qtr.	-20.80%	-7.30%	90.60%	8.10%
This Year	5.40%	5.50%	32.60%	-1.60%
Next Year	4.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	10.06%	N/A	N/A	N/A
Next 5 Years (per annum)	8.56%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.26	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	2.13	13.73	6.72	2.94

Currency in USD.

PNM Resources, Inc. (PNM)- NYSE

27.62 0.58(2.06%) 4:02PM EDT

After Hours : **27.62** 0.00 (0.00%) 4:33PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 8 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
○ Monthly
○ Dividends Only

Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	27.78	28.11	27.61	28.05	918,200	28.05
Sep 29, 2015	27.32	27.77	27.30	27.65	1,351,500	27.65
Sep 28, 2015	26.98	27.45	26.93	27.24	1,301,700	27.24
Sep 25, 2015	26.74	27.35	26.54	26.92	813,700	26.92
Sep 24, 2015	26.12	26.73	26.12	26.72	635,600	26.72
Sep 23, 2015	26.04	26.35	25.92	26.25	321,600	26.25
Sep 22, 2015	26.12	26.33	25.93	26.00	452,700	26.00
Sep 21, 2015	26.16	26.38	26.08	26.21	322,600	26.21
Sep 18, 2015	25.83	26.32	25.83	26.03	739,700	26.03
Sep 17, 2015	25.71	26.38	25.55	26.12	601,400	26.12
Sep 16, 2015	25.55	25.81	25.43	25.72	615,000	25.72
Sep 15, 2015	25.61	25.67	25.34	25.56	389,000	25.56
Sep 14, 2015	25.50	25.67	25.37	25.56	416,700	25.56
Sep 11, 2015	24.85	25.41	24.85	25.41	361,600	25.41
Sep 10, 2015	25.14	25.39	24.92	24.98	461,100	24.98
Sep 9, 2015	25.44	25.57	25.13	25.16	557,100	25.16
Sep 8, 2015	25.07	25.45	24.96	25.37	601,500	25.37
Sep 4, 2015	24.90	24.97	24.65	24.80	464,900	24.80
Sep 3, 2015	25.09	25.25	25.02	25.19	415,800	25.19
Sep 2, 2015	25.16	25.16	24.84	24.99	828,800	24.99
Sep 1, 2015	25.27	25.42	24.82	24.96	731,100	24.96
Aug 31, 2015	25.84	25.85	25.19	25.61	732,000	25.61
Aug 28, 2015	25.98	26.11	25.69	25.97	683,000	25.97
Aug 27, 2015	25.74	25.99	25.48	25.96	516,500	25.96
Aug 26, 2015	25.68	25.74	25.06	25.62	584,700	25.62
Aug 25, 2015	26.53	26.53	25.14	25.24	913,500	25.24
Aug 24, 2015	26.30	26.98	25.85	25.88	955,900	25.88
Aug 21, 2015	27.14	27.60	26.98	27.17	579,800	27.17
Aug 20, 2015	27.56	27.93	27.42	27.56	377,900	27.56
Aug 19, 2015	27.60	27.94	27.41	27.75	403,400	27.75
Aug 18, 2015	27.93	27.98	27.60	27.71	456,200	27.71
Aug 17, 2015	27.78	28.17	27.60	28.08	747,500	28.08
Aug 14, 2015	27.40	27.86	27.26	27.75	696,800	27.75
Aug 13, 2015	27.28	27.54	27.01	27.42	536,000	27.42
Aug 12, 2015	26.86	27.41	26.86	27.41	464,400	27.41
Aug 11, 2015	26.69	27.08	26.58	26.98	340,700	26.98
Aug 10, 2015	26.83	27.04	26.66	26.75	424,400	26.75
Aug 7, 2015	26.37	27.00	26.23	26.85	390,700	26.85
Aug 6, 2015	26.25	26.88	26.06	26.40	505,300	26.40

Aug 4, 2015	26.47	26.51	25.96	26.07	403,600	26.07
Aug 3, 2015	26.54	26.76	26.22	26.55	566,700	26.55
Jul 31, 2015	26.45	27.20	25.39	26.38	789,000	26.38
Jul 30, 2015	25.76	26.25	25.55	26.08	624,900	26.08
Jul 30, 2015	0.20 Dividend					
Jul 29, 2015	25.68	26.04	25.54	26.00	403,600	25.80
Jul 28, 2015	25.72	25.85	25.49	25.80	478,000	25.60
Jul 27, 2015	25.17	25.84	25.17	25.70	620,300	25.50
Jul 24, 2015	25.10	25.47	25.07	25.21	704,000	25.02
Jul 23, 2015	25.34	25.34	24.86	25.19	443,900	25.00
Jul 22, 2015	25.24	25.61	25.22	25.41	332,000	25.21
Jul 21, 2015	25.78	25.80	25.19	25.30	368,100	25.11
Jul 20, 2015	26.00	26.00	25.63	25.82	370,200	25.62
Jul 17, 2015	26.16	26.37	26.00	26.02	670,700	25.82
Jul 16, 2015	25.76	26.41	25.76	26.24	628,500	26.04
Jul 15, 2015	25.78	25.88	25.54	25.71	427,200	25.51
Jul 14, 2015	25.78	25.88	25.53	25.81	606,800	25.61
Jul 13, 2015	25.60	25.86	25.51	25.74	584,700	25.54
Jul 10, 2015	25.28	25.69	25.17	25.47	465,100	25.27
Jul 9, 2015	25.76	25.87	25.19	25.25	502,100	25.06
Jul 8, 2015	25.75	25.97	25.60	25.69	620,600	25.49

* Close price adjusted for dividends and splits.

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Look Up

Thu, Oct 29, 2015, 6:59PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13% Nasdaq 0.42%

POR

Portland General Electric Company (POR) - NYSE

36.96 0.45(1.20%) 4:03PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.62	0.76	2.11	2.35
No. of Analysts	7.00	4.00	14.00	14.00
Low Estimate	0.58	0.62	2.07	2.29
High Estimate	0.66	0.86	2.16	2.40
Year Ago EPS	0.55	0.62	2.18	2.11

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	541.97M	557.38M	1.96B	2.05B
No. of Analysts	4	3	11	11
Low Estimate	516.97M	470.83M	1.92B	1.98B
High Estimate	596.14M	678.22M	2.09B	2.18B
Year Ago Sales	500.00M	473.00M	1.90B	1.96B
Sales Growth (year/est)	8.40%	17.80%	3.20%	4.30%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.52	0.70	0.41	0.48
EPS Actual	0.55	0.62	0.44	0.40
Difference	0.03	-0.08	0.03	-0.08
Surprise %	5.80%	-11.40%	7.30%	-16.70%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.62	0.76	2.11	2.35
7 Days Ago	0.59	0.76	2.14	2.36
30 Days Ago	0.58	0.75	2.14	2.36
60 Days Ago	0.58	0.77	2.14	2.37
90 Days Ago	0.58	0.77	2.14	2.37

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	3	0	0	1
Up Last 30 Days	5	1	0	2
Down Last 30 Days	0	0	6	2
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	POR	Industry	Sector	S&P 500
Current Qtr.	12.70%	0.90%	-27.20%	3.30%
Next Qtr.	22.60%	-7.30%	90.60%	8.10%
This Year	-3.20%	5.50%	32.60%	-1.60%
Next Year	11.40%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	3.87%	N/A	N/A	N/A
Next 5 Years (per annum)	3.92%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	17.73	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.52	13.73	6.72	2.94

Currency in USD.

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Look Up

Thu, Oct 29, 2015, 7:20PM EDT - U.S. Markets closed Report an Issue

Dow 0.13% Nasdaq 0.42%

POR 1.20%

Portland General Electric Company (POR) - NYSE

36.96 0.45(1.20%) 4:03PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
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Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	36.33	37.03	36.11	36.97	792,500	36.97
Sep 29, 2015	36.29	36.68	35.98	36.14	1,273,900	36.14
Sep 28, 2015	36.38	36.74	36.15	36.39	808,200	36.39
Sep 25, 2015	36.12	36.97	35.91	36.51	799,100	36.51
Sep 24, 2015	35.53	36.14	35.26	36.06	1,134,900	36.06
Sep 23, 2015	35.18	35.72	35.07	35.70	942,900	35.70
Sep 23, 2015			0.30 Dividend			
Sep 22, 2015	35.56	35.93	35.44	35.61	704,800	35.31
Sep 21, 2015	35.66	36.00	35.44	35.85	690,100	35.55
Sep 18, 2015	35.14	35.81	35.14	35.51	1,672,000	35.21
Sep 17, 2015	34.90	35.86	34.90	35.43	640,900	35.13
Sep 16, 2015	34.79	35.16	34.66	34.94	536,600	34.65
Sep 15, 2015	34.67	34.81	34.37	34.75	410,500	34.46
Sep 14, 2015	34.50	34.91	34.50	34.66	481,300	34.37
Sep 11, 2015	33.97	34.53	33.82	34.52	420,700	34.23
Sep 10, 2015	34.29	34.46	34.00	34.11	519,200	33.82
Sep 9, 2015	34.80	34.93	34.21	34.28	917,000	33.99
Sep 8, 2015	34.17	34.80	34.11	34.76	925,500	34.47
Sep 4, 2015	33.77	33.96	33.59	33.72	1,003,300	33.44
Sep 3, 2015	33.73	34.19	33.33	34.11	1,003,300	33.82
Sep 2, 2015	33.99	33.99	33.39	33.70	1,148,600	33.42
Sep 1, 2015	34.10	34.26	33.53	33.70	781,200	33.42
Aug 31, 2015	34.82	34.93	34.10	34.54	1,789,700	34.25
Aug 28, 2015	35.13	35.25	34.47	34.97	583,800	34.68
Aug 27, 2015	35.00	35.15	34.53	35.13	757,900	34.83
Aug 26, 2015	34.63	34.83	33.74	34.72	1,107,300	34.43
Aug 25, 2015	35.43	35.59	34.11	34.16	1,155,800	33.87
Aug 24, 2015	35.95	36.33	34.95	35.05	898,700	34.75
Aug 21, 2015	36.48	37.19	36.47	36.73	840,200	36.42
Aug 20, 2015	37.20	37.55	37.00	37.04	773,300	36.73
Aug 19, 2015	37.26	37.63	37.05	37.35	865,200	37.04
Aug 18, 2015	37.67	37.79	37.36	37.43	531,900	37.11
Aug 17, 2015	37.63	38.00	37.38	37.77	515,000	37.45
Aug 14, 2015	37.21	37.68	37.04	37.62	966,600	37.30
Aug 13, 2015	37.24	37.49	36.91	37.25	985,200	36.94
Aug 12, 2015	36.70	37.43	36.61	37.36	975,900	37.05
Aug 11, 2015	36.25	36.82	36.13	36.79	833,000	36.48
Aug 10, 2015	36.23	36.63	36.10	36.26	632,800	35.95
Aug 7, 2015	35.81	36.34	35.66	36.19	530,400	35.89
Aug 6, 2015	35.77	35.92	35.50	35.88	557,100	35.58

Aug 5, 2015	35.78	36.00	35.68	35.72	331,100	35.42
Aug 4, 2015	36.09	36.10	35.57	35.65	389,800	35.35
Aug 3, 2015	36.11	36.41	35.91	36.13	452,700	35.83
Jul 31, 2015	35.90	36.47	35.90	36.01	568,200	35.71
Jul 30, 2015	35.43	36.02	35.26	35.67	974,800	35.37
Jul 29, 2015	34.71	35.52	34.53	35.50	1,076,400	35.20
Jul 28, 2015	33.38	34.77	33.31	34.76	1,113,000	34.47
Jul 27, 2015	33.79	34.26	33.50	34.18	1,043,700	33.89
Jul 24, 2015	33.76	34.09	33.15	33.82	610,800	33.54
Jul 23, 2015	34.10	34.13	33.51	33.76	534,200	33.48
Jul 22, 2015	33.90	34.36	33.80	34.18	339,400	33.89
Jul 21, 2015	34.20	34.28	33.80	33.99	604,000	33.70
Jul 20, 2015	34.45	34.49	34.09	34.26	580,700	33.97
Jul 17, 2015	34.97	35.05	34.48	34.50	628,300	34.21
Jul 16, 2015	34.49	35.15	34.49	35.07	647,800	34.77
Jul 15, 2015	34.36	34.54	34.00	34.49	561,400	34.20
Jul 14, 2015	34.46	34.56	34.30	34.36	780,400	34.07
Jul 13, 2015	34.55	34.72	34.25	34.44	421,400	34.15
Jul 10, 2015	34.11	34.73	33.99	34.36	654,400	34.07
Jul 9, 2015	34.55	34.87	34.01	34.14	787,100	33.85
Jul 8, 2015	34.65	34.89	34.46	34.48	551,400	34.19
Jul 7, 2015	34.20	34.97	34.16	34.77	790,100	34.48
Jul 6, 2015	33.81	34.10	33.66	34.06	671,000	33.77
Jul 2, 2015	33.63	33.99	33.60	33.79	527,100	33.51
Jul 1, 2015	33.21	33.43	33.09	33.41	527,800	33.13

* Close price adjusted for dividends and splits.

First | Previous | Next | Last

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Currency in USD.

Thu, Oct 29, 2015, 7:01PM EDT - U.S. Markets closed Report an Issue

Dow 0.13% Nasdaq 0.42%

Southern Company (SO) - NYSE

44.95 0.38(0.84%) 4:03PM EDT

After Hours : **44.94** 0.01 (0.02%) 5:18PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	0.43	0.59	2.84	2.94
No. of Analysts	11.00	7.00	21.00	20.00
Low Estimate	0.36	0.50	2.75	2.85
High Estimate	0.47	0.70	2.88	2.99
Year Ago EPS	0.38	0.56	2.80	2.84

Revenue Est	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	4.28B	4.48B	18.69B	19.26B
No. of Analysts	7	6	16	15
Low Estimate	3.15B	3.97B	17.60B	18.15B
High Estimate	5.08B	4.95B	20.25B	20.04B
Year Ago Sales	4.05B	4.18B	18.50B	18.69B
Sales Growth (year/est)	5.80%	7.00%	1.00%	3.00%

Earnings History	Dec 14	Mar 15	Jun 15	Sep 15
EPS Est	0.38	0.58	0.69	1.16
EPS Actual	0.38	0.56	0.71	1.17
Difference	0.00	-0.02	0.02	0.01
Surprise %	0.00%	-3.40%	2.90%	0.90%

EPS Trends	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Current Estimate	0.43	0.59	2.84	2.94
7 Days Ago	0.43	0.59	2.84	2.94
30 Days Ago	0.42	0.59	2.84	2.94
60 Days Ago	0.43	0.61	2.84	2.94
90 Days Ago	0.42	0.62	2.84	2.94

EPS Revisions	Current Qtr. Dec 15	Next Qtr. Mar 16	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	1	1	2
Up Last 30 Days	1	1	1	2
Down Last 30 Days	0	0	2	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	SO	Industry	Sector	S&P 500
Current Qtr.	13.20%	0.90%	-27.20%	3.30%
Next Qtr.	5.40%	-7.30%	90.60%	8.10%
This Year	1.40%	5.50%	32.60%	-1.60%
Next Year	3.50%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	4.81%	N/A	N/A	N/A
Next 5 Years (per annum)	3.58%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	15.96	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	4.46	13.73	6.72	2.94

Currency in USD.

Thu, Oct 29, 2015, 7:00PM EDT - U.S. Markets closed **Report an Issue**

Dow 0.13% Nasdaq 0.42%

Southern Company (SO) - NYSE

44.95 0.38(0.84%) 4:03PM EDT

After Hours : **44.94** 0.01 (0.02%) 5:18PM EDT

Historical Prices

Get Historical Prices for: GO

Set Date Range

Start Date: Jul 1 2015 Eg. Jan 1, 2010

End Date: Sep 30 2015

● Daily
○ Weekly
○ Monthly
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Get Prices

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	44.32	44.78	44.09	44.70	5,208,500	44.70
Sep 29, 2015	44.08	44.53	44.00	44.29	3,980,800	44.29
Sep 28, 2015	44.04	44.56	44.03	44.09	4,528,300	44.09
Sep 25, 2015	43.48	44.57	43.36	44.13	5,674,900	44.13
Sep 24, 2015	42.83	43.56	42.83	43.48	5,284,600	43.48
Sep 23, 2015	43.02	43.23	42.80	42.95	6,373,400	42.95
Sep 22, 2015	43.33	43.61	43.00	43.01	6,090,200	43.01
Sep 21, 2015	43.48	43.83	43.40	43.77	3,808,700	43.77
Sep 18, 2015	43.27	44.07	43.15	43.43	6,900,300	43.43
Sep 17, 2015	42.93	44.03	42.86	43.48	5,258,700	43.48
Sep 16, 2015	42.74	43.16	42.54	42.91	3,277,600	42.91
Sep 15, 2015	42.66	42.81	42.36	42.63	3,441,900	42.63
Sep 14, 2015	42.72	42.92	42.57	42.63	3,522,500	42.63
Sep 11, 2015	42.15	42.71	42.08	42.71	4,167,900	42.71
Sep 10, 2015	42.55	42.73	42.15	42.30	4,982,200	42.30
Sep 9, 2015	42.83	42.95	42.39	42.46	6,461,500	42.46
Sep 8, 2015	42.50	42.75	42.14	42.70	6,324,900	42.70
Sep 4, 2015	42.22	42.29	41.81	41.98	5,488,800	41.98
Sep 3, 2015	42.67	42.76	42.42	42.58	3,845,300	42.58
Sep 2, 2015	42.75	42.81	42.14	42.52	5,755,400	42.52
Sep 1, 2015	42.94	42.95	42.22	42.41	6,920,400	42.41
Aug 31, 2015	43.59	43.69	42.88	43.41	5,802,300	43.41
Aug 28, 2015	43.92	44.00	43.13	43.74	5,292,100	43.74
Aug 27, 2015	43.98	44.11	43.40	43.91	8,571,000	43.91
Aug 26, 2015	43.17	43.69	42.83	43.61	10,118,700	43.61
Aug 25, 2015	44.30	44.45	42.49	42.50	9,612,800	42.50
Aug 24, 2015	44.03	45.47	43.37	43.58	16,156,900	43.58
Aug 21, 2015	46.08	46.43	45.76	45.80	6,777,900	45.80
Aug 20, 2015	46.06	46.84	45.88	46.36	5,842,100	46.36
Aug 19, 2015	45.93	46.42	45.72	46.31	4,719,400	46.31
Aug 18, 2015	46.13	46.21	45.95	46.07	3,916,400	46.07
Aug 17, 2015	46.50	46.50	46.17	46.30	4,835,200	46.30
Aug 14, 2015	45.97	46.34	45.82	46.33	4,561,200	46.33
Aug 13, 2015	45.79	46.32	45.68	46.16	5,564,300	46.16
Aug 13, 2015	0.543 Dividend					
Aug 12, 2015	45.75	46.70	45.75	46.57	7,594,900	46.03
Aug 11, 2015	45.60	46.30	45.41	45.91	4,382,600	45.37
Aug 10, 2015	45.53	45.87	45.33	45.46	4,345,100	44.93
Aug 7, 2015	44.98	45.69	44.89	45.66	5,658,400	45.60

Aug 5, 2015	44.79	44.84	44.49	44.61	3,413,500	44.09
Aug 4, 2015	44.87	44.87	44.33	44.42	3,284,700	43.90
Aug 3, 2015	44.75	45.09	44.70	44.96	4,255,600	44.44
Jul 31, 2015	44.74	45.10	44.64	44.73	4,886,400	44.21
Jul 30, 2015	43.46	44.45	43.45	44.38	6,162,100	43.86
Jul 29, 2015	43.40	43.61	43.01	43.57	5,008,800	43.06
Jul 28, 2015	43.40	43.67	43.27	43.54	4,650,200	43.03
Jul 27, 2015	43.01	43.61	42.94	43.44	3,547,600	42.93
Jul 24, 2015	42.96	43.05	42.66	42.88	4,456,700	42.38
Jul 23, 2015	43.18	43.18	42.45	42.98	5,249,800	42.48
Jul 22, 2015	43.24	43.56	43.18	43.25	3,232,800	42.75
Jul 21, 2015	43.28	43.30	42.90	43.21	4,799,300	42.71
Jul 20, 2015	43.47	43.48	43.06	43.32	3,589,300	42.81
Jul 17, 2015	43.78	43.83	43.50	43.51	5,229,000	43.00
Jul 16, 2015	43.40	44.00	43.40	43.98	4,513,200	43.47
Jul 15, 2015	43.23	43.38	43.01	43.37	2,934,700	42.86
Jul 14, 2015	43.50	43.63	43.04	43.21	3,663,900	42.71
Jul 13, 2015	43.52	43.72	43.18	43.40	3,302,300	42.89
Jul 10, 2015	43.30	43.66	43.15	43.36	6,654,000	42.85
Jul 9, 2015	44.18	44.30	43.15	43.27	6,778,200	42.77
Jul 8, 2015	44.08	44.59	44.05	44.20	6,661,200	43.68
Jul 7, 2015	43.35	44.47	43.30	44.26	11,156,100	43.74
Jul 6, 2015	42.93	43.30	42.80	43.12	4,995,400	42.62
Jul 2, 2015	42.45	42.95	42.42	42.89	4,937,400	42.39
Jul 1, 2015	42.01	42.19	41.84	42.18	4,675,600	41.69

* Close price adjusted for dividends and splits.

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Currency in USD.

Westar Energy, Inc. (WR) - NYSE

39.64 0.26(0.65%) 4:04PM EDT

Analyst Estimates

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Earnings Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	1.04	0.35	2.25	2.44
No. of Analysts	7.00	5.00	13.00	13.00
Low Estimate	0.99	0.31	2.17	2.38
High Estimate	1.15	0.39	2.30	2.55
Year Ago EPS	1.10	0.32	2.35	2.25

Next Earnings Date: Nov 3, 2015 - Set a Reminder

Revenue Est	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Avg. Estimate	787.32M	631.18M	2.59B	2.72B
No. of Analysts	4	4	9	10
Low Estimate	764.20M	617.51M	2.44B	2.53B
High Estimate	811.76M	670.77M	2.65B	2.90B
Year Ago Sales	764.04M	596.44M	2.60B	2.59B
Sales Growth (year/est)	3.00%	5.80%	-0.40%	5.10%

Earnings History	Sep 14	Dec 14	Mar 15	Jun 15
EPS Est	1.07	0.35	0.43	0.42
EPS Actual	1.10	0.32	0.38	0.46
Difference	0.03	-0.03	-0.05	0.04
Surprise %	2.80%	-8.60%	-11.60%	9.50%

EPS Trends	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Current Estimate	1.04	0.35	2.25	2.44
7 Days Ago	1.04	0.35	2.25	2.44
30 Days Ago	1.05	0.35	2.25	2.44
60 Days Ago	1.05	0.36	2.25	2.45
90 Days Ago	1.04	0.38	2.24	2.45

EPS Revisions	Current Qtr. Sep 15	Next Qtr. Dec 15	Current Year Dec 15	Next Year Dec 16
Up Last 7 Days	1	2	1	1
Up Last 30 Days	1	2	1	1
Down Last 30 Days	2	1	1	0
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	WR	Industry	Sector	S&P 500
Current Qtr.	-5.50%	0.90%	-27.20%	3.30%
Next Qtr.	9.40%	-7.30%	90.60%	8.10%
This Year	-4.30%	5.50%	32.60%	-1.60%
Next Year	8.40%	6.10%	22.40%	9.40%
Past 5 Years (per annum)	11.66%	N/A	N/A	N/A
Next 5 Years (per annum)	3.40%	7.41%	6.67%	6.10%
Price/Earnings (avg. for comparison categories)	18.11	37.89	20.76	16.34
PEG Ratio (avg. for comparison categories)	5.33	13.73	6.72	2.94

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39.64 0.26(0.65%) 4:04PM EDT

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End Date: Sep 30 2015

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Prices

Date	Open	High	Low	Close	Volume	Adj Close*
Sep 30, 2015	38.06	38.49	37.87	38.44	1,000,600	38.44
Sep 29, 2015	37.88	38.11	37.61	37.88	815,400	37.88
Sep 28, 2015	38.07	38.27	37.70	37.87	984,800	37.87
Sep 25, 2015	37.67	38.53	37.47	38.08	1,290,800	38.08
Sep 24, 2015	37.20	37.74	37.03	37.59	1,145,500	37.59
Sep 23, 2015	36.93	37.34	36.92	37.31	599,800	37.31
Sep 22, 2015	37.04	37.31	36.79	36.94	571,000	36.94
Sep 21, 2015	37.21	37.53	37.08	37.23	662,600	37.23
Sep 18, 2015	36.85	37.45	36.81	37.07	1,502,200	37.07
Sep 17, 2015	36.60	37.69	36.48	37.27	991,900	37.27
Sep 16, 2015	36.25	36.74	36.01	36.67	707,000	36.67
Sep 15, 2015	36.04	36.25	35.81	36.19	726,400	36.19
Sep 14, 2015	36.24	36.44	36.00	36.03	670,400	36.03
Sep 11, 2015	35.42	36.18	35.36	36.17	975,000	36.17
Sep 10, 2015	35.50	36.03	35.45	35.55	949,700	35.55
Sep 9, 2015	36.07	36.17	35.51	35.55	905,200	35.55
Sep 8, 2015	35.43	36.00	35.43	35.94	1,271,700	35.94
Sep 4, 2015	35.44	35.58	34.90	35.05	907,000	35.05
Sep 4, 2015			0.36 Dividend			
Sep 3, 2015	35.66	36.06	35.60	35.90	898,600	35.54
Sep 2, 2015	35.81	35.93	35.20	35.59	922,900	35.23
Sep 1, 2015	36.32	36.34	35.33	35.49	1,030,900	35.13
Aug 31, 2015	36.91	36.91	36.13	36.55	1,512,900	36.18
Aug 28, 2015	37.20	37.28	36.59	37.08	841,100	36.71
Aug 27, 2015	36.85	37.18	36.47	37.17	1,063,300	36.80
Aug 26, 2015	36.22	36.77	35.74	36.68	1,491,800	36.31
Aug 25, 2015	37.53	37.63	35.92	35.94	1,453,600	35.58
Aug 24, 2015	37.67	37.85	36.96	37.15	1,701,800	36.78
Aug 21, 2015	38.97	39.29	38.68	38.68	1,289,200	38.29
Aug 20, 2015	39.41	39.74	39.20	39.24	846,300	38.85
Aug 19, 2015	39.40	39.71	39.14	39.57	1,021,700	39.17
Aug 18, 2015	39.79	40.07	39.47	39.53	1,082,800	39.13
Aug 17, 2015	39.73	40.22	39.53	39.87	1,437,700	39.47
Aug 14, 2015	39.12	39.83	39.10	39.74	2,663,100	39.34
Aug 13, 2015	38.62	39.36	38.42	39.24	1,664,300	38.85
Aug 12, 2015	38.28	39.01	38.19	38.86	1,303,500	38.47
Aug 11, 2015	37.82	38.53	37.76	38.30	1,441,700	37.92
Aug 10, 2015	37.93	38.38	37.77	37.79	1,181,700	37.41
Aug 7, 2015	37.18	38.21	36.99	37.99	1,787,500	37.61
Aug 6, 2015	37.22	37.35	36.80	37.22	1,629,200	36.85

Aug 5, 2015	37.23	37.71	37.13	37.23	1,259,900	36.86
Aug 4, 2015	37.63	37.70	37.20	37.29	766,200	36.92
Aug 3, 2015	37.73	37.99	37.57	37.77	791,300	37.39
Jul 31, 2015	37.69	37.98	37.40	37.65	1,348,900	37.27
Jul 30, 2015	36.82	37.46	36.68	37.31	1,240,500	36.94
Jul 29, 2015	36.19	36.96	36.14	36.90	1,264,800	36.53
Jul 28, 2015	35.99	36.48	35.88	36.47	1,249,400	36.10
Jul 27, 2015	35.57	36.31	35.57	36.18	604,300	35.82
Jul 24, 2015	35.47	35.68	35.41	35.56	1,215,400	35.20
Jul 23, 2015	35.75	35.86	35.06	35.51	1,291,900	35.15
Jul 22, 2015	35.60	36.06	35.60	35.82	724,300	35.46
Jul 21, 2015	35.91	36.10	35.40	35.58	931,900	35.22
Jul 20, 2015	36.25	36.27	35.77	35.99	579,900	35.63
Jul 17, 2015	36.44	36.54	36.23	36.30	912,700	35.94
Jul 16, 2015	36.09	36.60	36.01	36.55	944,400	36.18
Jul 15, 2015	35.92	36.03	35.73	36.01	846,500	35.65
Jul 14, 2015	36.23	36.48	35.89	35.93	1,161,300	35.57
Jul 13, 2015	36.67	36.82	36.02	36.17	974,400	35.81
Jul 10, 2015	36.08	36.89	36.01	36.56	2,319,400	36.19
Jul 9, 2015	36.41	36.50	35.81	36.10	1,408,300	35.74
Jul 8, 2015	36.17	36.61	36.11	36.31	1,211,900	35.95
Jul 7, 2015	35.55	36.53	35.50	36.31	1,313,100	35.95
Jul 6, 2015	35.31	35.55	35.11	35.46	1,054,400	35.10
Jul 2, 2015	34.97	35.37	34.82	35.32	1,455,900	34.97
Jul 1, 2015	34.31	34.76	34.17	34.70	1,494,200	34.35

* Close price adjusted for dividends and splits.

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Historical Inflation Rate

OCTOBER 15, 2015 BY TIM MCMAHON ON LEAVE A COMMENT

The table below provides the Historical U.S. Inflation Rate data from 1914 to the Present. For a smaller table with just the inflation rate data since the year 2000, see the Current Inflation page.

The ***Inflation rate*** is calculated from the Consumer Price Index (CPI-U) which is compiled by the U.S. Bureau of Labor Statistics and is based upon a 1982-84 Base of 100. Would you like to know the real definition of inflation or how to calculate inflation? or the monthly rather than annual inflation rate? To view the actual Consumer Price Index data that this inflation data is calculated from, go to the Historical CPI table.

Note: Due to the width of the table, this page is best viewed full screen or as wide as possible.

To see an in depth view of the inflationary makeup of each decade:
|1913-19 | 1920-29 | 1930-39 | 1940-49 | 1950-59 | 1960-69 | |1970-79 | 1980-89 |
Coming soon | 1990-99 | 2000-09 | 2010- Present |
Jump to Bottom of InflationTable or click "year" to reverse order. Click "Ave" to sort years by Average Annual inflation rate rather than date (click again to reverse).Blank Cells indicate that the data is not available because it has not been released by the Bureau of Labor Statistics yet.

Historical Annual U.S. Inflation Rate from 1913 to the present

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE.
2015	-0.09 %	-0.03 %	-0.07 %	-0.20 %	-0.04 %	0.12 %	0.17 %	0.20 %	-0.04 %				
2014	1.58 %	1.13 %	1.51 %	1.95 %	2.13 %	2.07 %	1.99 %	1.70 %	1.66 %	1.66 %	1.32 %	0.76 %	1.62 %
2013	1.59 %	1.98 %	1.47 %	1.06 %	1.36 %	1.75 %	1.96 %	1.52 %	1.18 %	0.96 %	1.24 %	1.50 %	1.47 %
2012	2.93 %	2.87 %	2.65 %	2.30 %	1.70 %	1.66 %	1.41 %	1.69 %	1.99 %	2.16 %	1.76 %	1.74 %	2.07 %
2011	1.63 %	2.11 %	2.68 %	3.16 %	3.57 %	3.56 %	3.63 %	3.77 %	3.87 %	3.53 %	3.39 %	2.96 %	3.16 %
2010	2.63 %	2.14 %	2.31 %	2.24 %	2.02 %	1.05 %	1.24 %	1.15 %	1.14 %	1.17 %	1.14 %	1.50 %	1.64 %
2009	0.03 %	0.24 %	-0.38 %	-0.74 %	-1.28 %	-1.43 %	-2.10 %	-1.48 %	-1.29 %	-0.18 %	1.84 %	2.72 %	-0.34 %
2008	4.28 %	4.03 %	3.98 %	3.94 %	4.18 %	5.02 %	5.60 %	5.37 %	4.94 %	3.66 %	1.07 %	0.09 %	3.85 %

2007	2.08 %	2.42 %	2.78 %	2.57 %	2.69 %	2.69 %	2.36 %	1.97 %	2.76 %	3.54 %	4.31 %	4.08 %	2.85 %
2006	3.99 %	3.60 %	3.36 %	3.55 %	4.17 %	4.32 %	4.15 %	3.82 %	2.06 %	1.31 %	1.97 %	2.54 %	3.24 %
2005	2.97 %	3.01 %	3.15 %	3.51 %	2.80 %	2.53 %	3.17 %	3.64 %	4.69 %	4.35 %	3.46 %	3.42 %	3.39 %
2004	1.93 %	1.69 %	1.74 %	2.29 %	3.05 %	3.27 %	2.99 %	2.65 %	2.54 %	3.19 %	3.52 %	3.26 %	2.68 %
2003	2.60 %	2.98 %	3.02 %	2.22 %	2.06 %	2.11 %	2.11 %	2.16 %	2.32 %	2.04 %	1.77 %	1.88 %	2.27 %
2002	1.14 %	1.14 %	1.48 %	1.64 %	1.18 %	1.07 %	1.46 %	1.80 %	1.51 %	2.03 %	2.20 %	2.38 %	1.59 %
2001	3.73 %	3.53 %	2.92 %	3.27 %	3.62 %	3.25 %	2.72 %	2.72 %	2.65 %	2.13 %	1.90 %	1.55 %	2.83 %
2000	2.74 %	3.22 %	3.76 %	3.07 %	3.19 %	3.73 %	3.66 %	3.41 %	3.45 %	3.45 %	3.45 %	3.39 %	3.38 %
1999	1.67 %	1.61 %	1.73 %	2.28 %	2.09 %	1.96 %	2.14 %	2.26 %	2.63 %	2.56 %	2.62 %	2.68 %	2.19 %
1998	1.57 %	1.44 %	1.37 %	1.44 %	1.69 %	1.68 %	1.68 %	1.62 %	1.49 %	1.49 %	1.55 %	1.61 %	1.55 %
1997	3.04 %	3.03 %	2.76 %	2.50 %	2.23 %	2.30 %	2.23 %	2.23 %	2.15 %	2.08 %	1.83 %	1.70 %	2.34 %
1996	2.73 %	2.65 %	2.84 %	2.90 %	2.89 %	2.75 %	2.95 %	2.88 %	3.00 %	2.99 %	3.26 %	3.32 %	2.93 %
1995	2.80 %	2.86 %	2.85 %	3.05 %	3.19 %	3.04 %	2.76 %	2.62 %	2.54 %	2.81 %	2.61 %	2.54 %	2.81 %
1994	2.52 %	2.52 %	2.51 %	2.36 %	2.29 %	2.49 %	2.77 %	2.90 %	2.96 %	2.61 %	2.67 %	2.67 %	2.61 %
1993	3.26 %	3.25 %	3.09 %	3.23 %	3.22 %	3.00 %	2.78 %	2.77 %	2.69 %	2.75 %	2.68 %	2.75 %	2.96 %
1992	2.60 %	2.82 %	3.19 %	3.18 %	3.02 %	3.09 %	3.16 %	3.15 %	2.99 %	3.20 %	3.05 %	2.90 %	3.03 %
1991	5.65 %	5.31 %	4.90 %	4.89 %	4.95 %	4.70 %	4.45 %	3.80 %	3.39 %	2.92 %	2.99 %	3.06 %	4.25 %
1990	5.20 %	5.26 %	5.23 %	4.71 %	4.36 %	4.67 %	4.82 %	5.62 %	6.16 %	6.29 %	6.27 %	6.11 %	5.39 %
1989	4.67 %	4.83 %	4.98 %	5.12 %	5.36 %	5.17 %	4.98 %	4.71 %	4.34 %	4.49 %	4.66 %	4.65 %	4.83 %
1988	4.05 %	3.94 %	3.93 %	3.90 %	3.89 %	3.96 %	4.13 %	4.02 %	4.17 %	4.25 %	4.25 %	4.42 %	4.08 %
1987	1.46 %	2.10 %	3.03 %	3.78 %	3.86 %	3.65 %	3.93 %	4.28 %	4.36 %	4.53 %	4.53 %	4.43 %	3.66 %
1986	3.89 %	3.11 %	2.26 %	1.59 %	1.49 %	1.77 %	1.58 %	1.57 %	1.75 %	1.47 %	1.28 %	1.10 %	1.91 %
1985	3.53 %	3.52 %	3.70 %	3.69 %	3.77 %	3.76 %	3.55 %	3.35 %	3.14 %	3.23 %	3.51 %	3.80 %	3.55 %
1984	4.19 %	4.60 %	4.80 %	4.56 %	4.23 %	4.22 %	4.20 %	4.29 %	4.27 %	4.26 %	4.05 %	3.95 %	4.30 %
1983	3.71 %	3.49 %	3.60 %	3.90 %	3.55 %	2.58 %	2.46 %	2.56 %	2.86 %	2.85 %	3.27 %	3.79 %	3.22 %
1982	8.39 %	7.62 %	6.78 %	6.51 %	6.68 %	7.06 %	6.44 %	5.85 %	5.04 %	5.14 %	4.59 %	3.83 %	6.16 %
1981	11.83 %	11.41 %	10.49 %	10.00 %	9.78 %	9.55 %	10.76 %	10.80 %	10.95 %	10.14 %	9.59 %	8.92 %	10.35 %
1980	13.91 %	14.18 %	14.76 %	14.73 %	14.41 %	14.38 %	13.13 %	12.87 %	12.60 %	12.77 %	12.65 %	12.52 %	13.58 %
1979	9.28 %	9.86 %	10.09 %	10.49 %	10.85 %	10.89 %	11.26 %	11.82 %	12.18 %	12.07 %	12.61 %	13.29 %	11.22 %
1978													

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Selected Interest Rates (Weekly) - H.15

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Current Release (48 KB PDF)

Release Date: November 2, 2015

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site. If Monday is a holiday, the weekly release will be posted on Tuesday after the holiday and the daily update will not be posted on that Tuesday.

November 2, 2015
H.15 Selected Interest Rates
Yields in percent per annum

Instruments	2015 Oct 26	2015 Oct 27	2015 Oct 28	2015 Oct 29	2015 Oct 30	Week Ending		2015 Oct
						Oct 30	Oct 23	
Federal funds (effective) 1 2 3	0.12	0.12	0.12	0.12	0.07	0.12	0.13	0.12
Commercial Paper 3 4 5 6								
Nonfinancial								
1-month	0.09	0.09	0.14	0.09	0.07	0.10	0.12	0.11
2-month	0.13	0.16	0.18	0.14	0.12	0.15	0.14	0.14
3-month	0.18	0.20	0.14	0.19	n.a.	0.18	0.18	0.18
Financial								
1-month	n.a.	0.12	n.a.	n.a.	n.a.	0.12	0.14	0.13
2-month	0.17	0.17	0.18	0.19	n.a.	0.18	0.18	0.19
3-month	0.25	0.23	0.24	0.25	0.26	0.25	0.24	0.25
Eurodollar deposits (London) 3 7								
1-month	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
3-month	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
6-month	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Bank prime loan 2 3 8	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Discount window primary credit 2 9	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
U.S. government securities								
Treasury bills (secondary market) 3 4								
4-week	0.01	0.01	0.03	0.02	0.01	0.02	0.04	0.01
3-month	0.02	0.03	0.04	0.07	0.08	0.05	0.01	0.02
6-month	0.16	0.18	0.21	0.21	0.22	0.20	0.12	0.11
1-year	0.23	0.27	0.31	0.31	0.32	0.29	0.22	0.25
Treasury constant maturities								
Nominal 10								
1-month	0.01	0.01	0.03	0.02	0.01	0.02	0.04	0.01
3-month	0.02	0.03	0.04	0.07	0.08	0.05	0.01	0.02
6-month	0.16	0.18	0.21	0.21	0.23	0.20	0.12	0.11
1-year	0.25	0.29	0.33	0.33	0.34	0.31	0.23	0.26
2-year	0.66	0.65	0.73	0.75	0.75	0.71	0.64	0.64
3-year	0.94	0.92	1.00	1.05	1.05	0.99	0.91	0.93
5-year	1.41	1.38	1.47	1.53	1.52	1.46	1.38	1.39

7-year	1.78	1.75	1.83	1.90	1.88	1.83	1.76	1.76
10-year	2.07	2.05	2.10	2.19	2.16	2.11	2.06	2.07
20-year	2.50	2.48	2.50	2.60	2.57	2.53	2.50	2.50
30-year	2.87	2.86	2.87	2.96	2.93	2.90	2.89	2.89
Inflation indexed 11								
5-year	0.25	0.23	0.33	0.34	0.32	0.29	0.23	0.21
7-year	0.41	0.39	0.48	0.50	0.47	0.45	0.41	0.39
10-year	0.59	0.57	0.63	0.67	0.63	0.62	0.59	0.57
20-year	0.96	0.95	0.98	1.02	0.98	0.98	0.99	0.98
30-year	1.19	1.18	1.20	1.24	1.19	1.20	1.23	1.22
Inflation-indexed long-term average 12	0.96	0.95	0.99	1.02	0.98	0.98	0.99	0.97
Interest rate swaps 13								
1-year	0.50	0.49	0.50	0.55	0.56	0.52	0.48	0.49
2-year	0.75	0.73	0.75	0.84	0.85	0.79	0.73	0.75
3-year	1.00	0.96	0.99	1.10	1.11	1.03	0.98	0.99
4-year	1.22	1.17	1.21	1.32	1.33	1.25	1.20	1.21
5-year	1.41	1.36	1.40	1.50	1.51	1.44	1.39	1.40
7-year	1.71	1.67	1.70	1.80	1.81	1.74	1.71	1.71
10-year	2.01	1.97	2.00	2.08	2.09	2.03	2.01	2.01
30-year	2.51	2.47	2.51	2.56	2.56	2.52	2.54	2.53
Corporate bonds								
Moody's seasoned								
Aaa 14	3.90	3.89	3.91	4.04	3.98	3.94	3.92	3.95
Baa	5.29	5.30	5.30	5.40	5.35	5.33	5.33	5.34
State & local bonds 15				3.66		3.66	3.67	3.67
Conventional mortgages 16				3.76		3.76	3.79	3.80

n.a. Not available.

Footnotes

1. The daily effective federal funds rate is a weighted average of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp/).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Source: Bloomberg and CTRB ICAP Fixed Income & Money Market Products.

8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.

10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at www.treasury.gov/resource-center/data-chart-center/interest-rates/. Source: U.S. Treasury.

Arizona Department of Administration

Arizona's Workforce Employment Report

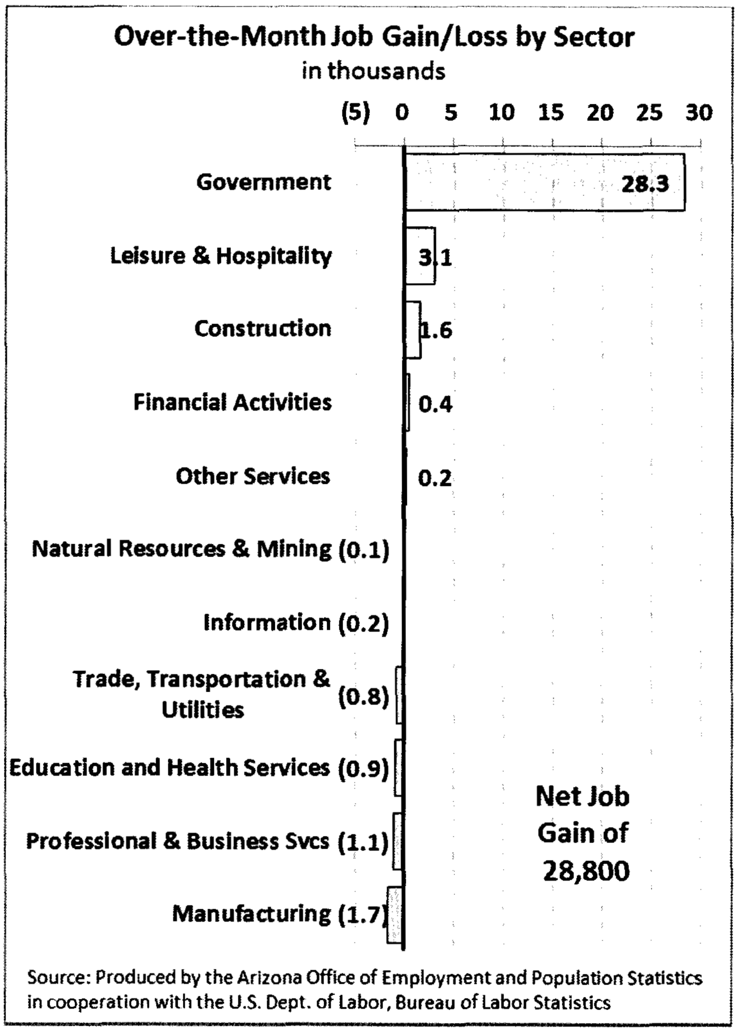
AZ.GOV Arizona's Official Web Site

October 15, 2015

Nonfarm Job Gains Above Historic Average; Unemployment Rate Remains Unchanged at 6.3%

Arizona's seasonally adjusted unemployment rate remained unchanged at 6.3% in September. The U.S. seasonally adjusted unemployment rate remained unchanged at 5.1% in September. A year ago, the Arizona seasonally adjusted rate was 6.6% and the U.S. rate was 5.9% (see **Figure 1**).

Figure 2


Over-the-Month Job Gain/Loss by Sector
in thousands

Source: Produced by the Arizona Office of Employment and Population Statistics in cooperation with the U.S. Dept. of Labor, Bureau of Labor Statistics

Figure 1

Arizona, U.S. Economic Indicators

Unemployment Rate (Seasonally Adj.)

	Sept'15	*Aug'15*	*Sept'14*
United States	*5.1%*	*5.1%*	*5.9%*
Arizona	*6.3%*	*6.3%*	*6.6%*
Arizona unadjusted rate	*6.4%*	*6.8%*	*6.9%*

Arizona Nonfarm Employment (in Thousands)

	Sept'15	*Aug'15*	*Sept'14*
Overall	*2,633.2*	*2,604.4*	*2,575.1*
Over-Month % Chg.	*1.1%*	*1.6%*	*1.0%*
Year-to-Year % Chg.	*2.3%*	*2.2%*	*1.7%*

Over the Month

Arizona gained 28,800 Nonfarm jobs (1.1%) in September (see **Figure 2**). This was more than the post-recessionary ('10-'14) average gain of 25,300 jobs. The Private Sector gained 500 jobs, less than the post-recessionary ('10-'14) average gain of 3,100 jobs. Government gained 28,300 jobs, with the majority of gains occurring in Local (18,900 jobs) and State (11,900 jobs) Government Education. Gains were recorded in five of the eleven sectors, while the remaining six posted losses. The largest gain was recorded in Government (28,300 jobs), followed by Leisure and Hospitality (3,100 jobs), Construction (1,600 jobs), Financial Activities (400 jobs) and Other Services (200 jobs). The largest losses occurred in Manufacturing (-1,700 jobs) and Professional and Business Services (-1,100 jobs), the majority recorded within Administrative and Support and Waste (-800 jobs) and Professional, Scientific and Technical Services (-600). Other sectors which recorded losses include Education and Health

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Arizona

Arizona

Data Series	Back Data	Apr 2015	May 2015	June 2015	July 2015	Aug 2015	Sept 2015
Labor Force Data							
Civilian Labor Force (1)		3,163.9	3,165.3	3,156.2	3,145.8	3,141.1	(P) 3,144.2
Employment (1)		2,973.1	2,981.1	2,971.5	2,954.3	2,944.3	(P) 2,947.1
Unemployment (1)		190.8	184.2	184.8	191.4	196.8	(P) 197.1
Unemployment Rate (2)		6.0	5.8	5.9	6.1	6.3	(P) 6.3
Nonfarm Wage and Salary Employment							
Total Nonfarm (3)		2,613.2	2,610.4	2,611.6	2,619.6	2,626.8	(P) 2,631.5
12-month % change		2.2	2.3	1.9	2.1	2.2	(P) 2.2
Mining and Logging (3)		12.9	12.7	12.6	12.8	12.6	(P) 12.5
12-month % change		-1.5	-2.3	-3.8	-2.3	-3.1	(P) -4.6
Construction (3)		127.7	127.0	127.2	129.6	129.2	(P) 130.3
12-month % change		0.9	1.3	2.3	4.9	5.1	(P) 6.3
Manufacturing (3)		155.5	155.9	155.4	155.3	156.3	(P) 155.0
12-month % change		-0.6	-0.5	-0.7	-0.8	-0.1	(P) -0.9
Trade, Transportation, and Utilities (3)		496.7	495.4	496.9	498.9	501.7	(P) 500.3
12-month % change		1.2	0.9	1.0	1.3	1.6	(P) 1.2
Information (3)		43.4	43.1	43.7	43.8	43.3	(P) 43.9
12-month % change		0.9	0.9	0.7	-0.2	-1.1	(P) 0.9
Financial Activities (3)		192.7	194.1	192.8	195.1	196.0	(P) 196.4
12-month % change		2.6	3.0	2.2	3.2	3.3	(P) 3.3
Professional & Business Services (3)		391.0	394.7	395.7	398.3	394.3	(P) 393.2
12-month % change		3.3	3.8	3.7	4.0	2.4	(P) 1.8
Education & Health Services (3)		391.6	391.7	394.3	393.3	397.3	(P) 395.5
12-month % change		3.5	3.3	3.8	3.2	4.0	(P) 3.5
Leisure & Hospitality (3)		293.8	294.8	292.9	295.1	295.8	(P) 299.1
12-month % change		3.1	3.4	2.7	3.5	3.3	(P) 4.2
Other Services (3)		94.4	94.3	93.6	93.7	93.2	(P) 93.6
12-month % change		7.9	7.8	7.0	6.8	6.0	(P) 5.6
Government (3)		413.5	406.7	406.5	403.7	407.1	(P) 411.7
12-month % change		0.9	1.1	-1.0	-1.5	-0.8	(P) 0.1

Footnotes
(1) Number of persons, in thousands, seasonally adjusted.
(2) In percent, seasonally adjusted.
(3) Number of jobs, in thousands, seasonally adjusted.
(P) Preliminary

Data extracted on: October 30, 2015

Source: U.S. Bureau of Labor Statistics
Note: More data series, including additional geographic areas, are available through the "Databases & Tables" tab at the top of this page.

Arizona includes the following metropolitan areas for which an Economy At A Glance table is

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United States

United States - Monthly Data

Data Series	Back Data	Apr 2015	May 2015	June 2015	July 2015	Aug 2015	Sept 2015
Unemployment Rate (1)	🦕	5.4	5.5	5.3	5.3	5.1	5.1
Change in Payroll Employment (2)	🦕	187	260	245	223	(P) 136	(P) 142
Average Hourly Earnings (3)	🦕	24.89	24.95	24.95	25.01	(P) 25.10	(P) 25.09
Consumer Price Index (4)	🦕	0.1	0.4	0.3	0.1	-0.1	-0.2
Producer Price Index (5)	🦕	-0.1	0.5	(P) 0.2	(P) 0.2	(P) 0.0	(P) -0.5
U.S. Import Price Index (6)	🦕	-0.2	1.1	0.1	(R) -1.0	(R) -1.6	(R) -0.1

Footnotes
(1) In percent, seasonally adjusted. Annual averages are available for Not Seasonally Adjusted data.
(2) Number of jobs, in thousands, seasonally adjusted.
(3) Average Hourly Earnings for all employees on private nonfarm payrolls.
(4) All items, U.S. city average, all urban consumers, 1982-84=100, 1-month percent change, seasonally adjusted.
(5) Final Demand, 1-month percent change, seasonally adjusted.
(6) All imports, 1-month percent change, not seasonally adjusted.
(R) Revised
(P) Preliminary

United States - Quarterly Data

Data Series	Back Data	3rd Qtr 2014	4th Qtr 2014	1st Qtr 2015	2nd Qtr 2015	3rd Qtr 2015
Employment Cost Index (1)	🦕	0.7	0.5	0.7	0.2	0.6
Productivity (2)	🦕	3.1	-2.2	-1.1	(R) 3.3	

Footnotes
(1) Compensation, all civilian workers, quarterly data, 3-month percent change, seasonally adjusted.
(2) Output per hour, nonfarm business, quarterly data, percent change from previous quarter at annual rate, seasonally adjusted.
(R) Revised

Data extracted on: October 30, 2015

Source: U.S. Bureau of Labor Statistics
Note: More data series, including additional geographic areas, are available through the "Databases & Tables" tab at the top of this page.

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PO Box 711, Tucson, Arizona 85702-0711

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Phoenix, AZ 85007

Re: Notice of Compliance Filing – Credit Rating Upgrades
Docket Nos. E-04230A-14-0011 and E-01933A-14-0011

Pursuant to Condition No. 45 of the Settlement Agreement approved by the Commission in Decision No. 74689 (August 12, 2014) which requires Fortis Inc. and UNS Energy Corporation to report to the Commission and RUCO any changes in the credit ratings of Fortis Inc., UNS Energy Corporation or the Regulated Utilities, UNS Energy hereby provides notice that on February 27, 2015, Moody's Investor Service upgraded the senior secured ratings of UNS Energy Corporation to Baa1 from Baa2 and the senior unsecured and issuer ratings of Tucson Electric Power Company (TEP), UNS Gas, Inc. (UNSG) and UNS Electric, Inc. (UNSE) to A3 from Baa1.

The full report announcing credit upgrades for UNS Energy Corporation and the Regulated Utilities can be found at https://www.moodys.com/research/Moodys-upgrades-UNS-Energy-Corp-and-its-subsidiaries-outlooks-are--PR_319042.

Please contact me if you have any questions.

ORIGINAL

Sincerely,

Bradley S. Carroll
Assistant General Counsel, State Regulatory

BSC:jh

Arizona Corporation Commission
DOCKETED
MAR 05 2015
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Original and 13 copies filed with Docket Control
cc: David Tenney, RUCO
Compliance Section

MOODY'S
INVESTORS SERVICE

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Rating Action: Moody's Assigns Baa1 Senior Unsecured Rating to UNS Energy's Bank Credit Facility

Global Credit Research - 24 Sep 2015

New York, September 24, 2015 -- Moody's Investors Service ("Moody's") assigned a Baa1 senior unsecured rating to UNS Energy Corporation's (UNS: Baa1 stable) new $150 million Senior Unsecured Revolving Credit and Letter of Credit Facility. The new senior unsecured credit facility will replace the existing $125 million senior secured credit facility expiring in November 2016. At the same time, Moody's assigned an A3 senior unsecured rating to Tucson Electric Power Company's (TEP: A3 stable) new $250 million senior unsecured revolving credit facility and UNS Gas, Inc. (UNSG: A3 stable) and UNS Electric, Inc.'s (UNSE: A3 stable) new $100 million joint revolving credit facility. All three facilities will expire in October 2020. Upon closing of the new credit facilities, the ratings on the existing revolving credit facilities will be withdrawn. The rating outlooks are stable.

"UNS Energy's Baa1 senior unsecured rating is the same rating as the prior senior secured rating because we did not assign any material value to the security claim under the existing credit facility because the collateral was in the form of subsidiary stock, excluding the principal subsidiary, TEP" said Jeffrey Cassella, Vice President.

RATINGS RATIONALE

UNS Energy's Baa1 senior unsecured rating is the same as UNS Energy's current senior secured rating given that the security was limited to the stock of certain subsidiaries, excluding UNS Energy's largest subsidiary, TEP. As a result, we assigned no notching lift to its security collateral and already viewed UNS Energy's credit quality to an unsecured claim within the consolidated capital structure.

UNS Energy's Baa1 rating reflects structural subordination relative to its A3 senior unsecured rated operating utility subsidiaries, TEP, UNSG, and UNSE and their improved financial profile. The rating reflects a constructive Arizona regulatory environment, which allow a suite of timely recovery mechanisms; and the expectation that financial metrics will remain stable, including UNS Energy's ratio of cash flow from operations before working capital changes (CFO pre-W/C) to debt in the low 20% range over the next few years. In addition, UNS Energy's rating reflects the stable cash flows (i.e., upstream dividends) provided by its regulated utility subsidiaries with the expectation of renewed economic growth in Arizona balanced against TEP's relatively concentrated service territory and large coal generation exposure, which they are diversifying over time.

The stable rating outlook for UNS Energy and its subsidiaries reflects our expectation that the credit supportiveness of the Arizona regulatory environment is sustained; stable cash flows continue at each subsidiary due to reasonable and timely recoveries of fuel and purchased power costs such that UNS Energy's CFO pre-W/C to debt will continue in the low 20% range, and economic growth in Arizona continues to improve.

What Could Change the Rating -- Up

UNS Energy's rating could be upgraded if the economic growth in Arizona resumes at pre-recession levels which contributes to further strengthening of financial metrics or if there was an improvement in the regulatory environment that led to meaningfully greater predictability, timeliness and/or sufficiency of rates such that financial metrics improve on a sustained basis including CFO pre-W/C to debt in the mid-20% range. UNS Energy's rating could be upgraded if its principal subsidiary, TEP, were to be upgraded.

What Could Change the Rating - Down

UNS Energy's rating outlook could be downgraded if a more contentious regulatory environment re-emerged in Arizona that resulted in a deterioration in the credit supportiveness of the regulatory framework which might include greater regulatory lag, uncertainty about the recovery of investments, further compression in rates (especially if accompanied by a rise in interest rates) or if financial metrics deteriorated such that CFO pre-W/C to debt were to decline to high teens range on a sustained basis.

Rating Assigned:

Assignments:

..Issuer: Tucson Electric Power Company

....Senior Unsecured Bank Credit Facility, Assigned A3

..Co-Issuers: UNS Electric, Inc./UNS Gas, Inc.

....Senior Unsecured Bank Credit Facility, Assigned A3

..Issuer: UNS Energy Corporation

....Senior Unsecured Bank Credit Facility, Assigned Baa1

Headquartered in Tucson, Arizona, UNS Energy, which was acquired by Fortis Inc. (Fortis: not rated) on August 15, 2014, is a utility holding company, whose principal subsidiary is Tucson Electric Power Company, a vertically integrated regulated electric utility in southern Arizona. UNS Energy is parent of UniSource Energy Services, Inc. (UES: not rated), an intermediate holding company, that holds the common stock of UNS Gas, Inc., a small regulated natural gas distribution company in Arizona, and UNS Electric, Inc., a small vertically integrated regulated electric utility in Arizona.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in December 2013. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

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Related Issuers

- Tucson Electric Power Company
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- Rating Action: Moody's upgrades UNS Energy Corp. and its subsidiaries; outlooks are stable
- 🔒Sector Comment: US Regulated Electric and Gas Utilities: Arizona's Constructive Regulatory Environment Supports the Credit Quality of Its Investor-Owned Regulated Utilities

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Home > News & Events > 2015 Monetary Policy Releases

Press Release

Print

Release Date: October 28, 2015

For immediate release

Information received since the Federal Open Market Committee met in September suggests that economic activity has been expanding at a moderate pace. Household spending and business fixed investment have been increasing at solid rates in recent months, and the housing sector has improved further; however, net exports have been soft. The pace of job gains slowed and the unemployment rate held steady. Nonetheless, labor market indicators, on balance, show that underutilization of labor resources has diminished since early this year. Inflation has continued to run below the Committee's longer-run objective, partly reflecting declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation moved slightly lower; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators continuing to move toward levels the Committee judges consistent with its dual mandate. The Committee continues to see the risks to the outlook for economic activity and the labor market as nearly balanced but is monitoring global economic and financial developments. Inflation is anticipated to remain near its recent low level in the near term but the Committee expects inflation to rise gradually toward 2 percent over the medium term as the labor market improves further and the transitory effects of declines in energy and import prices dissipate. The Committee continues to monitor inflation developments closely.

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 whether it will be appropriate to raise the target range at its next meeting, 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 and international developments. The Committee anticipates that it will be appropriate to raise the target range for the federal funds rate when it has seen some further improvement in the labor market and is reasonably confident that inflation will move back to its 2 percent objective over the medium term.

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. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; Charles L. Evans; Stanley Fischer; Dennis P. Lockhart; Jerome H. Powell; Daniel K. Tarullo; and John C. Williams. Voting against the action was Jeffrey M. Lacker, who preferred to raise the target range for the federal funds rate by 25 basis points at this meeting.

2015 Monetary Policy Releases

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Home > News & Events > 2015 Monetary Policy Releases

Press Release

Print

Release Date: September 17, 2015

For immediate release

Information received since the Federal Open Market Committee met in July suggests that economic activity is expanding at a moderate pace. Household spending and business fixed investment have been increasing moderately, and the housing sector has improved further; however, net exports have been soft. The labor market continued to improve, with solid job gains and declining unemployment. On balance, labor market indicators show that underutilization of labor resources has diminished since early this year. Inflation has continued to run below the Committee's longer-run objective, partly reflecting declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation moved lower; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Recent global economic and financial developments may restrain economic activity somewhat and are likely to put further downward pressure on inflation in the near term. Nonetheless, the Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators continuing to move toward levels the Committee judges consistent with its dual mandate. The Committee continues to see the risks to the outlook for economic activity and the labor market as nearly balanced but is monitoring developments abroad. Inflation is anticipated to remain near its recent low level in the near term but the Committee expects inflation to rise gradually toward 2 percent over the medium term as the labor market improves further and the transitory effects of declines in energy and import prices dissipate. The Committee continues to monitor inflation developments closely.

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 and international developments. The Committee anticipates that it will be appropriate to raise the target range for the federal funds rate when it has seen some further improvement in the labor market and is reasonably confident that inflation will move back to its 2 percent objective over the medium term.

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. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

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Dow 0.46%

$DJI

Dow Jones Industrial Average (^DJI) - DJI

17,784.86 82.72(0.46%) 11:11AM EST

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Prices

Date	Open	High	Low	Close	Avg Vol	Adj Close*
Nov 2, 2015	17,672.62	17,977.85	17,655.02	17,867.58	130,970,000	17,867.58
Oct 1, 2015	16,278.62	17,799.96	16,013.66	17,663.54	125,215,400	17,663.54
Sep 1, 2015	16,528.03	16,933.43	15,942.37	16,284.70	138,191,400	16,284.70
Aug 3, 2015	17,696.74	17,704.76	15,370.33	16,528.03	136,560,900	16,528.03
Jul 1, 2015	17,638.12	18,137.12	17,399.17	17,689.86	97,288,100	17,689.86
Jun 1, 2015	18,017.82	18,188.81	17,576.50	17,619.51	106,622,700	17,619.51
May 1, 2015	17,859.27	18,351.36	17,733.12	18,010.68	98,613,000	18,010.68
Apr 1, 2015	17,778.52	18,175.56	17,585.01	17,840.52	109,717,100	17,840.52
Mar 2, 2015	18,134.05	18,288.63	17,579.27	17,776.12	117,725,000	17,776.12
Feb 2, 2015	17,169.99	18,244.38	17,037.76	18,132.70	97,492,600	18,132.70
Jan 2, 2015	17,823.07	17,951.78	17,136.30	17,164.95	117,091,000	17,164.95
Dec 1, 2014	17,827.27	18,103.45	17,067.59	17,823.07	104,533,600	17,823.07
Nov 3, 2014	17,390.90	17,894.83	17,278.36	17,828.24	84,050,500	17,828.24
Oct 1, 2014	17,040.46	17,395.54	15,855.12	17,390.52	131,515,200	17,390.52
Sep 2, 2014	17,097.42	17,350.64	16,934.43	17,042.90	93,944,700	17,042.90
Aug 1, 2014	16,561.70	17,153.80	16,333.78	17,098.45	74,480,800	17,098.45
Jul 1, 2014	16,828.53	17,151.56	16,563.30	16,563.30	81,479,500	16,563.30
Jun 2, 2014	16,716.85	16,978.02	16,673.65	16,826.60	87,897,100	16,826.60
May 1, 2014	16,580.26	16,735.51	16,341.30	16,717.17	83,254,700	16,717.17
Apr 1, 2014	16,458.05	16,631.63	16,015.32	16,580.84	99,044,200	16,580.84
Mar 3, 2014	16,321.71	16,505.70	16,046.99	16,457.66	104,783,300	16,457.66
Feb 3, 2014	15,697.69	16,398.95	15,340.69	16,321.71	165,366,800	16,321.71
Jan 2, 2014	16,572.17	16,573.07	15,617.55	15,698.85	110,196,600	15,698.85
Dec 2, 2013	16,087.12	16,588.25	15,703.79	16,576.66	101,710,400	16,576.66
Nov 1, 2013	15,558.01	16,174.51	15,522.18	16,086.41	94,472,500	16,086.41
Oct 1, 2013	15,132.49	15,721.00	14,719.43	15,545.75	100,898,600	15,545.75
Sep 3, 2013	14,801.55	15,709.58	14,777.48	15,129.67	124,693,500	15,129.67
Aug 1, 2013	15,503.85	15,658.43	14,760.41	14,810.31	111,977,700	14,810.31
Jul 1, 2013	14,911.60	15,634.32	14,858.93	15,499.54	125,829,500	15,499.54
Jun 3, 2013	15,123.55	15,340.09	14,551.27	14,909.60	157,952,000	14,909.60
May 1, 2013	14,839.80	15,542.40	14,687.05	15,115.57	135,470,000	15,115.57
Apr 1, 2013	14,578.54	14,887.51	14,434.43	14,839.80	139,476,300	14,839.80
Mar 1, 2013	14,054.49	14,585.10	13,937.60	14,578.54	135,001,500	14,578.54
Feb 1, 2013	13,860.58	14,149.15	13,784.01	14,054.49	140,248,900	14,054.49
Jan 2, 2013	13,104.30	13,969.99	13,104.30	13,860.58	139,489,500	13,860.58
Dec 3, 2012	13,027.73	13,365.86	12,883.89	13,104.14	140,624,500	13,104.14
Nov 1, 2012	13,099.19	13,290.75	12,471.49	13,025.58	135,952,300	13,025.58
Oct 1, 2012	13,437.66	13,661.87	13,017.37	13,096.46	124,321,900	13,096.46
Sep 4, 2012	13,092.15	13,653.24	12,977.09	13,437.13	149,906,300	13,437.13
Aug 1, 2012	13,007.47	13,330.76	12,778.90	13,090.84	103,785,200	13,090.84

Jul 2, 2012	12,879.71	13,128.64	12,492.25	13,008.68	128,766,100	13,008.68
Jun 1, 2012	12,391.56	12,898.94	12,035.09	12,880.09	148,347,600	12,880.09
May 1, 2012	13,214.16	13,338.66	12,311.56	12,393.45	147,960,900	12,393.45
Apr 2, 2012	13,211.36	13,297.11	12,710.56	13,213.63	135,138,500	13,213.63
Mar 1, 2012	12,952.29	13,289.08	12,734.86	13,212.04	153,390,000	13,212.04
Feb 1, 2012	12,632.76	13,055.75	12,632.76	12,952.07	144,731,500	12,952.07
Jan 3, 2012	12,221.19	12,841.95	12,221.19	12,632.91	157,457,500	12,632.91
Dec 1, 2011	12,046.21	12,328.47	11,735.19	12,217.56	150,864,200	12,217.56
Nov 1, 2011	11,951.53	12,187.51	11,231.43	12,045.68	169,042,800	12,045.68
Oct 3, 2011	10,912.10	12,284.31	10,404.49	11,955.01	194,929,500	11,955.01
Sep 1, 2011	11,613.30	11,716.84	10,597.14	10,913.38	219,510,400	10,913.38
Aug 1, 2011	12,144.22	12,282.42	10,604.07	11,613.53	279,694,300	11,613.53
Jul 1, 2011	12,414.34	12,753.89	12,083.45	12,143.24	166,169,500	12,143.24
Jun 1, 2011	12,569.41	12,569.49	11,862.53	12,414.34	184,383,600	12,414.34
May 2, 2011	12,810.16	12,876.00	12,309.52	12,569.79	180,300,400	12,569.79
Apr 1, 2011	12,321.02	12,832.83	12,093.89	12,810.54	184,985,500	12,810.54
Mar 1, 2011	12,226.49	12,383.46	11,555.48	12,319.73	175,563,900	12,319.73
Feb 1, 2011	11,892.50	12,391.29	11,892.50	12,226.34	180,002,100	12,226.34
Jan 3, 2011	11,577.43	12,020.52	11,573.87	11,891.93	194,415,000	11,891.93
Dec 1, 2010	11,007.23	11,625.00	11,007.23	11,577.51	152,101,300	11,577.51
Nov 1, 2010	11,120.30	11,451.53	10,929.28	11,006.02	192,471,400	11,006.02
Oct 1, 2010	10,789.72	11,247.60	10,711.12	11,118.49	189,376,100	11,118.49
Sep 1, 2010	10,016.01	10,948.88	10,016.01	10,788.05	189,500,400	10,788.05
Aug 2, 2010	10,468.82	10,719.94	9,936.62	10,014.72	198,771,300	10,014.72
Jul 1, 2010	9,773.27	10,584.99	9,614.32	10,465.94	211,975,200	10,465.94
Jun 1, 2010	10,133.94	10,594.16	9,753.84	9,774.02	235,307,700	9,774.02
May 28, 2010	10,258.00	10,258.00	10,095.90	10,136.63	487,440,000	10,136.63

*** Close price adjusted for dividends and splits.**

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Currency in USD.

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

DIRECT TESTIMONY
OF
JEFFREY M. MICHLIK

ON BEHALF OF THE
RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2015

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY

UNS Electric, Inc. ("UNS or Company") is an Arizona "C" Corporation. UNS is a for profit, certificated Arizona public service corporation that provides electric utility service to various communities in Santa Cruz County and Mohave County, Arizona. On May 5, 2015, UNS filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The UNS corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

UNS Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both Tucson Electric Power (TEP) and UniSource Energy Services (UES). TEP serves more than 414,000 customers in and around Tucson, while UES provides natural gas and electric service to about 243,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

The Company utilized a test year ended December 31, 2014.

Rate Application denoted in thousands of dollars:

The Company-proposed rates, as filed, produce total operating revenue of $171.557 million, an increase of $22.621 million or 15.19 percent, over adjusted test year revenue of $148.936 million. The Company-proposed revenue will provide operating income of $22.108 million and a 6.22 percent rate of return on its proposed $355.720 million fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $164.298 million an increase of $12.271 million or 8.07 percent, from the RUCO-adjusted test year revenue of $152.027 million. RUCO's recommended revenue will provide operating income of $18.147 million and a 5.26 percent return on the $345.131 million RUCO-adjusted FVRB.

RUCO recommends that the Company update its lead-lag study in the next rate case.

RUCO recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its membership expenses. Further, the Commission should send a strong message to the Company that ***all*** EEI membership may be disallowed in the future if this information is not provided.

<u>Other Items</u>:

RUCO recommends denial of the Company's proposed deferral of property taxes.

RUCO recommends a 50/50 sharing between shareholders and ratepayers in its appeal of the Arizona Department of Revenues ("ADOR") assessment of its Gila River Power Plant. RUCO also recommends a reasonable cap be placed on legal expenses; once this level is exceeded, the Company shareholders should bear any extra costs.

RUCO recommends that the deferred savings accrued as a result of the Deferred Accounting Order related to the acquisition of Gila River Plant be credited back to ratepayers over a three year period through the PPFAC.

RUCO recommends that the current PPFAC not be modified.

I. INTRODUCTION

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

A. My name is Jeffrey M. Michlik. I am a Public Utilities Analyst V employed by the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. In my capacity as a Public Utilities Analyst V, I analyze and examine accounting, financial, statistical and other information and prepare reports based on my analyses that present RUCO's recommendations to the Arizona Corporation Commission ("Commission") on utility revenue requirements, rate design and other matters. I also provide expert testimony on these same issues.

Q. Please describe your educational background and professional experience.

A. In 2000, I graduated from Idaho State University, receiving a Bachelor of Business Administration Degree in Accounting and Finance, and I am a Certified Public Accountant with the Arizona State Board of Accountancy. I have attended the National Association of Regulatory Utility Commissioners' ("NARUC") Utility Rate School, which presents for study and review general regulatory and business issues. I have also attended various other NARUC sponsored events.

I joined RUCO as a Public Utilities Analyst V in September of 2013. Prior to my employment with RUCO, I worked for the Arizona Corporation Commission in the Utilities Division as a Public Utilities Analyst for a little over seven years. Prior to employment with the Commission, I worked one year in public accounting as a Senior Auditor, and four years for the Arizona Office of the Auditor General as a Staff Auditor.

Q. What is the scope of your testimony in this case?

A. I am presenting RUCO's analysis and recommendations on UNS's proposed revenue requirement for UNS' application for a permanent rate increase. I am also presenting testimony and schedules addressing rate base, operating revenues and expenses. In addition, Mr. Robert Mease will be addressing Cost of Capital, and Mr. Lon Huber will be addressing rate design.

Q. What is the basis of your testimony in this case?

A. I performed a regulatory audit of the Company's application and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission-adopted FERC Uniform System of Accounts ("USOA").

Q. How is your testimony organized?

A. My testimony is presented in six sections. Section I is this introduction. Section II provides a background of the Company. Section III is a summary of the Company's filing and RUCO's rate base and operating income adjustments. Section IV presents RUCO's rate base recommendations. Section V presents RUCO's operating income recommendations. Section VI presents RUCO's recommendations on other issues identified during our review.

II. BACKGROUND

Q. Please review the background of this application.

A. UNS Electric, Inc. ("UNS or Company") is an Arizona "C" Corporation. UNS is a for profit, certificated Arizona public service corporation that provides electric utility service to various communities in Santa Cruz County and Mohave County, Arizona. On May 5, 2015, UNS filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The UNS corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

Q. Can you provide additional background on UNS' corporate structure?

A. Yes. UNS Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both Tucson Electric Power (TEP) and UniSource Energy Services (UES). TEP serves more than 414,000 customers in and around Tucson, while UES provides natural gas and electric service to about 243,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

III. SUMMARY OF FILING, RECOMMENDATIONS, AND ADJUSTMENTS.

Q. Please summarize the Company's proposals in this filing.

A. Based on the Company's schedules filed on May 5, 2015, the Company has proposed the following rounded to the nearest $1,000:

The Company-proposed rates, as filed, produce total operating revenue of $171.557 million, an increase of $22.621 million or 15.19 percent, over adjusted test year revenue of $148.936 million. The Company-proposed revenue will provide operating income of $22.108 million and a 6.22 percent rate of return on its proposed $355.720 million fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $164.298 million an increase of $12.271 million or 8.07 percent, from the RUCO-adjusted test year revenue of $152.027 million. RUCO's recommended revenue will provide operating income of $18.147 million and a 5.26 percent return on the $345.131 million RUCO-adjusted FVRB (see RUCO schedule JMM-1).

Q. For the purposes of this rate case, has RUCO accepted the Company's gross revenue conversion factor of 1.6084?

A. Yes, see RUCO schedule JMM-2.

Q. Please summarize RUCO's rate base adjustments.

A. The two rate base adjustment(s) are presented below:

Rate Base Adjustment No. 1 - Net Operating Loss Carryforward ("NOLC") Accumulated Deferred Income Tax ("ADIT") Offset – This adjustment reverses the Company's pro-forma adjustment in the amount of $7,467,062, as this methodology was recently rejected by the Commission.

Rate Base Adjustment No. 2 - Allowance for Cash Working Capital - This adjustment applies to the cash working capital and the prepaid insurance component of the Company's working capital allowance, and increases cash working capital by $5,429.

Q. Please summarize RUCO's operating revenue and expense adjustments.

A. The eleven operating income adjustment(s) are presented below:

Operating Income Adjustment No. 1 - Current Charges Authorized by the Commission not applied to Test Year Billing Determinants – This adjustment uses the Commission authorized tariff rates and applies them to the Company's adjusted test year billing determinants. This adjustment increases adjusted test year electric retail sales by $3,090,705.

Operating Income Adjustment No. 2 – Not Used

Operating Income Adjustment No. 3 – Medical and Dental Expense Normalization - This adjustment normalizes medical and dental expenses that fluctuate year to year, and reduces adjusted test year medical and dental expenses by $305,848.

Operating Income Adjustment No. 4 – Officers and Directors Insurance ("D&O") Expense – This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This reduces adjusted test year D&O expense by $70,077.

Operating Income Adjustment No. 5 – Wellness Incentive Program, Employee Recognition, and Spot Awards Expense - These adjustments reduces expenses that are not necessary to the provision of electric service and have been eliminated. These adjustments reduce adjusted test year expenses by $46,551.

Operating Income Adjustment No. 6 – UNS Short-Term Incentive Program Expense - This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces adjusted test year short-term incentive program expense by $169,700.

Operating Income Adjustment No. 7 – Injuries and Damages Expense – This adjustment removes items that RUCO believes should not be included in injuries and damages expense. This adjustment reduces injuries and damages expense by $343,815.

Operating Income Adjustment No. 8 – Edison Electric Institute ("EEI") Dues – This adjustment removes expense items that do not benefit ratepayers, and reduces adjusted test year EEI dues by $15,517.

Operating Income Adjustment No. 9 – Rate Case Expense – This adjustment reduces estimated rate case expense by $16,667 to account for what RUCO has determined to be just and reasonable.

Operating Income Adjustment No. 10 – Interest Synchronization Expense – This adjustment resynchronizes interest expense based on RUCO's recommended rate bases and increases adjusted test year income taxes by $58,805.

Operating Income Adjustment No. 11 – Income Tax Expense – This adjustment increases income tax by $1,526,666 to account for RUCO's adjustments to operating expenses.

IV. RATE BASE

Fair Value Rate Base ("FVRB")

Q. Did the Company prepare a schedule showing the elements of a Reconstruction Cost New Depreciated ("RCND") Rate Base?

A. Yes. The Company derived its FVRB by taking the average of the Original Cost Rate Base ("OCRB") and RCND. This methodology has been accepted by the Commission in prior decisions.

Q. Has RUCO presented its schedules to reflect OCRB, RCND and FVRB?

A. Yes. For purposes of this presentation, I have used the Company's OCRB information as the starting point for RUCO's determination of the Company's FVRB.

Rate Base Summary

Q. Please summarize RUCO's adjustments to the Company's OCRB base denoted in thousands.

A. RUCO's adjustments to the Company's rate base resulted in a net decrease of $7.462 million, from $272.013 million to $264.551 million the decrease was primarily due to RUCO's adjustments: (1) to the NOLC ADIT offset and (2) to cash working capital, as shown on RUCO schedules 4, and 5.

Rate Base Adjustment No. 1 – Net Operating Loss Carryforward ("NOLC") Accumulated Deferred Income Tax ("ADIT") Offset

Q. Has the Company proposed an adjustment to reduce its ADIT balance by its NOLC ADIT offset?

A. Yes.

Q. What is the rationale behind this adjustment?

A. The Company relies on three Internal Revenue Service ("IRS") private letters to support its position.

Q. What is an IRS private letter ruling?

A. From the IRS website "A private letter ruling, or PLR, is a written statement issued to a taxpayer that interprets and applies tax laws to the taxpayer's represented set of facts. A PLR is issued in response to a written request submitted by a taxpayer. A PLR may not be relied on as precedent by other taxpayers or by IRS personnel."

Q. Has the Company asked for a private letter ruling from the IRS in this case?

A. No.

Q. Has the Company excluded a private letter ruling that did not support its position in this case?

A. Yes. On May 2, 2014, the IRS issued PLR 201418024 regarding the treatment of deferred tax assets (DTAs) for NOL carryforwards under the deferred tax normalization requirements of Treas. Reg. § 1.167(1)-1(h)(1)(iii). The PLR held that not including the NOL carryforward DTA in rate base, the methodology advocated by the applicable public utility commission, complied with the normalization requirements in a specific circumstance.

Q. Has the Commission adhered to or followed the IRS code and GAAP (which is covered in Accounting Standards Codification ("ASC") 740 Income Taxes) in the past?

A. No. In fact, in the case of Limited Liability Corporations ("LLC's") and Subchapter S Corporations ("Sub S") the Commission has created its own tax methodology for ratemaking purposes.

Q. Please elaborate?

A. Under the Commission's Income Tax Policy (see attachment A, followed by RUCO's comments) the ratepayers now have to pay the utility owners personal tax liability under pass through corporate organization (Chapter S and Limited Liability Corporation), The Commission's tax policy provides for what in RUCO's opinion is a **"phantom tax"**. Thus, the Commission can create its own tax policy any time it wants and is not bound by GAAP.

Q. More importantly how has the Commission treated this issue?

A. Recently the Commission in Decision No. 75268 (dated September 8, 2015), stated on page, 34, line 15. "A fundamental tenet of ratemaking is that a utility should earn a return only on used and useful assets financed by investors. Since ADIT is a source of non-investor capital, matching of plant with ADIT in the calculation of rate base is appropriate. In this case, RUCO's ADIT recommendations provide the best matching. We also believe that ratepayers should not be deprived of rate base recognition of ADIT arising from income tax timing differences when bonus depreciation results in an NOL. The circumstances that result in an NOL are subject to decisions by utility management, not ratepayers, and since an NOL can be carried forward to future years, it represents an asset that a utility can use to provide a tax benefit in future years. Accordingly, we will adopt RUCO's proposed ADIT adjustments."

Needless to say RUCO agrees with the Commission's Decision, and there is no reason ratepayers should not benefit now.

Q. What is RUCO's recommendation?

A. RUCO recommends increasing the ADIT balance by $7,467,062 from $35,161,108 to $42,628,170, as shown in RUCO schedule JMM-6.

Rate Base Adjustment No. 2 – Allowance for Working Capital

Q. What is cash working capital?

A. Working capital measures the amount of investors' funds that must be used to sustain the day to day operations of the Company, in this case on average over a test year. In general the components of cash working capital are fuel inventory; materials and supplies inventories; prepayments; and cash working capital.

Q. Has RUCO made adjustments to any of these components?

A. Yes. RUCO has adjusted the Company's prepayments in regards to Directors and Officers ("D&O") Insurance. RUCO has removed the D&O insurance which will be discussed in greater detail in RUCO's Operating Adjustment No. 4, that D&O insurance be shared equally between ratepayers and shareholders. In this case RUCO recommends a sharing of the D&O prepaid insurance of $40,055, after applying the ACC jurisdiction ratio, RUCO has reduced the prepaid insurance by $19,092.

RUCO has also adjusted the Company's cash working component, usually an area of disagreement. RUCO notes that the Company's lead-lag study dates back to 2005. RUCO recommends that the Company update its lead-lag study in the next rate case. RUCO has adjusted its expenses to flow through the Company's lead-lag summary, and reduces the working capital allowance by $5,429 from $7,174,709 to $7,169,280, as shown in RUCO schedule JMM-7.

V. OPERATING INCOME

Operating Income Summary

Q. What are the results of RUCO's analysis of test year revenues, expenses, and operating income?

A. RUCO's analysis resulted in adjusted test year operating revenues of $152.027 million, operating expenses of $141.509 million and operating income of $10.517 million, as shown on RUCO schedules 8 and 9. RUCO made eleven adjustments to operating expenses, as presented below.

Operating Income Adjustment No. 1 – Current Charges authorized by the Commission not applied to adjusted test year billing determinants.

Q. Please describe the Companies process of adjusting its billing determinants?

A. The Company starts with the unadjusted billing determinants, and then adjusts the billing determinants for customer annualization, and weather normalization. For example, the ***unadjusted test*** year billing determinants from the 2015 UNSE Revenue Proof were as follows:[1]

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[1] To simplify the example, I have excluded the TCA, Base Power, and PPFAC.

Table I. Unadjusted Test Year Revenues

[A]	[B]	[C]	[D]
Rate Schedule	Current Rates	Test Year Billing Determinants	Test Year Billed Revenues
5703 RESIDENTIAL SERVICE			
Basic Service Charge	$10.00	910,158	$9,101,580
Energy Charge 1st 400 kWh	$0.019300	306,169,110	5,909,064
Energy Charges 401 - 1,000 kWh	$0.034350	265,903,606	9,133,789
Energy Charge, all additional kWh	$0.038499	182,932,901	7,042,734
Total			$31,187,166

Table II. Adjusted Test Year Revenues

[A]	[B]	[C]	[D]
Rate Schedule	Current Rates	Test Year Billing Determinants	Test Year Billed Revenues
5703 RESIDENTIAL SERVICE			
Basic Service Charge	$10.00	912,420	$9,124,200
Energy Charge 1st 400 kWh	$0.019300	305,205,763	5,890,471
Energy Charges 401 - 1,000 kWh	$0.034350	265,302,752	9,113,150
Energy Charge, all additional kWh	$0.038499	190,706,885	7,342,024
Total			$31,469,845

Table III. Proposed Revenues

[A]	[B]	[C]	[D]
Rate Schedule	Proposed Rates	Test Year Billing Determinants	Test Year Billed Revenues
5703 RESIDENTIAL SERVICE			
Basic Service Charge	$20.00	912,420	$18,248,400
Energy Charge 1st 400 kWh	$0.030810	305,205,763	9,403,390
Energy Charges 401 - 1,000 kWh	$0.050810	265,302,752	13,480,033
Energy Charge, all additional kWh	$0.050810	190,706,885	9,689,817
Total			$50,821,639

As can be seen, in Table II Column [C] the Company has adjusted its billing determinants for each of the above categories (e.g. Basic Service Charge from $910,158 to $912,420) for the effects of customer annualization and weather normalization from Table I Column [C]. It is important to note that both Column B from Table I and Table II is the ***Commission Authorized***

Current Rate, as shown in the Company's H-3 schedule and its authorized tariff. The Company in Table III Column [C] utilizes the adjusted test year billing determinants from Table II Column [C] and applies its proposed rates ***which have not been authorized by the Commission*** to generate its proposed revenue.

Q. Did RUCO tie out both the Companies test year and proposed revenues?

A. Yes, for each customer class (e.g. residential, small commercial, large general service, etc.) and for each component (e.g. basic service charge, energy charge 1st 400 kWh, etc.).

Q. Did you encounter any discrepancies along the way?

A. Yes, a minor one and a large one.

Q. Please explain the minor discrepancy first?

A. The Company's Residential Bright Community Solar Class's adjusted H-5 utilized 959 customer billing determinants should tie to the Company's adjusted test year billing determinants, but it did not. The Company in response to RUCO data request 4.03, provided a revised H-5 schedules that utilized 944 customers billing determinants (15 less). The Company claims that some customers were billed twice in the same month.

Q. Please explain the second discrepancy?

A. The second discrepancy involves the Company applying its proposed rates to its adjusted test year billing determinants to derive its adjusted test-year revenue.

Q. Was this widespread or limited to a certain class of customer class?

A. The error seems to be isolated to customer rate classes that the Company has moved into new rate classes.

Q. Please explain and show the billing migration from the former customer classes to the new customer classes?

A. Based on the Public Version – Revenue Proof, the Company is proposing the following changes:

Customer Rate Class	Billing Determinants		Customer Rate Class	Billing Determinants	Migrating Billing Determinants
Large General Service	16,092	moved to	New Medium Service	15,972	120
Large Power Service 3<69 KV	84	moved to	New Large General Service	84 Plus 120 = 204	0
Large General Service TOU	96	moved to	New Medium General Service TOU	96	0
Large Power Service 3 TOU<69KV	24	moved to	New Large Service TOU	24	0

Q. Please provide an example.

A. Provided is an example that accounts for most of the total discrepancy. For the total RUCO adjustment please see RUCO schedule JMM-10.

Customer Class	Current Rates	Test Year Billing Determinents	Adjusted Test Year Revenues
5713 LARGE GENERAL SERVICE			
Basic Service Charge	$ 50.000000	16,092	$ 804,600
Demand Charge, per kW	$ 12.810000	1,394,255	$ 17,860,410
Energy Charge, per kWh	$ 0.005470	445,782,493	$ 2,438,430
TCA, per kW	$ 0.432900	0	$ -
Margin Total			
Base Power	$ 0.056603	445,782,493	$ 25,232,626
PPFAC Revenue	Varies by Month		
Total Fuel Revenue			
Total Large General Service			$ 46,336,067

The highlighted Base Power Charge indicates the current charge $ 0.056603 authorized by the Commission that ties to the Company's H-3 tariff (see Attachment B for a copy of the Company's current tariffs that are in question). The test year revenues based on the adjusted billing determinants and current authorized Commission charge produce test year revenues of $46,336,067.

The Company reduced the proposed Base Power Charge to $0.048440 and used this rate which has not been authorized by the Commission to produce its test year revenues of $42,697,144. A difference of $3,638,922, (i.e. $46,336,067 - $42,697,144) as shown below:

Customer Class	Current Rates	Test Year Billing Determinents	Adjusted Test Year Revenues
5713 LARGE GENERAL SERVICE			
Basic Service Charge	$ 50.000000	16,092	$ 804,600
Demand Charge, per kW	$ 12.810000	1,394,255	$ 17,860,410
Energy Charge, per kWh	$ 0.005470	445,782,493	$ 2,438,430
TCA, per kW	$ 0.432900	0	$ -
Margin Total			
Base Power	$ 0.048440	445,782,493	$ 21,593,704
PPFAC Revenue	Varies by Month		
Total Fuel Revenue			
Total Large General Service			$ 42,697,144

Q. Please state the total difference between the Company's test year revenues and RUCO's tie-out of the Company's test year revenues?

A. The Company's test year revenues for all classes totaled $147,178,138. RUCO's test year revenues for all classes total $150,268,843. The difference of $3,090,705, and the differences between the other three customer classes is shown in RUCO schedule JMM-10.

Q. Did you ask the Company to explain these discrepancies and why they used the proposed unauthorized Commission rates to calculate their test year revenues?

A. Yes. In response to RUCO data request 4.12, the Company stated they were rebalancing their fuel costs. However, you still cannot use proposed rates to calculate your current adjusted test year revenues. The Company is free to rebalance its fuel costs and propose any changes and charges in its proposed rates.

Q. What other unintended consequences does this present?

A. The Company's H-4's schedules for these customers' classes are misstated.

Q. Please state the total difference between the Company's proposed revenues and RUCO's tie-out of the Company's proposed revenues?

A. The difference between RUCO's and the Company is $9,681.

Q. Can you reconcile the difference?

A. Yes. The difference is related to Residential Service Bright Arizona Community Solar – Base Power Supply Charge, all kWhs. The Company carried over the current rate of 0.08451 instead of its proposed rate of 0.069260 resulting in the difference of $9,681 (i.e. 53,651 – 43,970).

Operating Income Adjustment No. 2 – Weather Normalization

Q. Has the Company proposed an adjustment for Weather Normalization?

A. Yes, the Company proposed a weather normalization adjustment.

Q. Is RUCO making an adjustment at this time?

A. No. RUCO is in the process of issuing more data requests. RUCO reserves the right to update its recommendation in its surrebuttal testimony after it becomes aware of all the facts.

Q. Did the Company use a new weather normalization model?

A. Yes. In response to RUCO data request 1.16, the utilization of the new weather normalization model costs is an approximate $2,015,578 loss for ratepayers versus the old method.

Q. Is RUCO aware of any Company proposing a weather normalization adjustment that benefits or adds-on to test year revenues?

A. No. RUCO likens this to a rigged game at the county fair, the ratepayer always loses, and in this case it just depends on how much which RUCO intends to find out.

Operating Income Adjustment No. 3 – Medical and Dental Expense Normalization

Q. Did the Company provide its medical and dental expenses for the test year and prior two years?

A. Yes, along with its retirement expenses, vision expense, administrative expenses, and other insurance expenses, the Company in its response to data request # 1.029, explained all variances over/under 10 percent. The Company stated that the discount rate for the pension expense, had increased and decreased. RUCO looked at a three year average and determined the test year amount was not materially different from the three year average amount (i.e. $246,498 test year, $246,756 three year average). However, in regards to medical and dental expenses the Company stated "Due to the nature of self-funded plans, expenditures fluctuate with usage, and are significantly impacted by the number of serious medical conditions of participants." RUCO agrees with the

Company's statement and has normalized both medical and dental expenses over a three year period to reflect a more realistic and reasonable amount.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing medical expenses by $316,694, and increasing dental expenses by $10,846, as shown in RUCO schedule JMM-12.

Operating Income Adjustment No. 4 – Director and Officers' ("D&O") Liability Insurance

Q. What is D&O Liability Insurance?

A. D&O liability Insurance is liability insurance that covers directors and officers for claims made against them by shareholders or others for decisions they may make.

Q. Has the Company requested that ratepayers bear the full burden of this cost?

A. Yes.

Q. What is the total amount of D&O Liability Insurance included in adjusted test year expenses?

A. $140,155 ($145,954 x ACC Raito of 96.0266 percent).

Q. What is RUCO's recommendation?

A. RUCO recommends a 50/50 sharing between ratepayers and shareholders, since D&O Liability Insurance not only benefits ratepayers, but also shareholders. Shareholders benefit from insurance coverage in litigation cases brought against the Company's Director and Officers. Shareholders would also benefit from payments under this policy which may not be recoverable from ratepayers. Similarly, it can be argued that ratepayers benefit, since the Company can attract and retain directors and officers, and provides them with some degree of freedom from personal liability. Therefore, it is reasonable for shareholders to bear a portion of the cost for the D&O liability insurance. RUCO recommends reducing D&O liability insurance by $70,077 from $140,154 to $70,077, as shown in RUCO schedule JMM-13.

Operating Income Adjustment No. 5 – Wellness Incentive Program, Employee Recognition, and Spot Awards

Q. Has the Company asked ratepayers to pay for the costs of the Wellness Incentive Program, Employee Recognition, and Spot Awards?

A. Yes.

Q. What are the amounts of these programs?

A. In response to RUCO data requests 2.03 and 2.04 the Company stated the following amounts were expended:

Wellness Incentive Program - $15,738
Employee Recognition - $10,740
Spot Awards - $22,000

Q. Does RUCO believe these costs are necessary for the provision of electrical services?

A. No, and these costs should be absorbed by the shareholders.

Q. What is RUCO's recommendation?

A. RUCO recommends reducing administrative and general expense by $48,478 (i.e. 15,738+10,740+22,000), and on an ACC jurisdictional basis $46,551, as shown in RUCO schedule JMM-14.

Operating Income Adjustment No. 6 – UNS's Short-Term Incentive Program ("PEP")

Q. Has the Company asked for ratepayers to fund 100 percent of its incentive compensation program?

A. Yes, and 100 percent of the pro-forma adjustment.

Q. Briefly describe the PEP?

A. According to Company data request Uniform Data Request ("UDR") 1.034, "The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2014, the objectives were (i) net income; (ii) O&M cost containment; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2014 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, and process improvements. According to the Company, this balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders. The outcomes of which all benefit our customers in the long run.

The financial and other metrics for the Company's 2014 Short-Term Incentive Compensation program were:

- Financial – 50% • Net Income – 40%
- O&M Cost Containment – 10%
- Excellent Operations and Safe Work Environment – 50%"

Q. What are the amounts of the PEP test year expense and Pro-forma amount?

A. The Company stated in its response to RUCO data request # 2.05 that it is seeking recovery of $674,000 in PEP in this rate case. However, in the Company's pro-forma Income-Incentive Compensation excel spreadsheet, after adjustments, the Company is requesting a total of $326,753 consisting of the test year amount of $151,471 and the pro-forma amount of $175,282, as shown in RUCO schedule JMM-15.

Q. Does RUCO agree with the calculation of the Pro-forma amount?

A. No. The Company has projected pay increases of 2 percent, and taxes for future years 2016 and 2017, which are not known and measureable.

Q. Has RUCO recalculated this amount?

A. RUCO's recalculation of the Company's pro-forma adjustment amount results in a decrease of $12,112 from $175,282 to $163,170.

Q. Does PEP benefit both ratepayers and shareholders?

A. Yes. As the Company stated above.

Q. What is RUCO's recommendation?

A. RUCO again recommends a 50/50 sharing between shareholders and ratepayers. RUCO recommends that incentive compensation expense be reduced by $169,700 after application of the ACC jurisdictional ratio, as shown in RUCO schedule JMM-15.

Operating Income Adjustment No. 7 – Injuries and Damages

Q. Has the Company taken a three year average of injuries and damages to try to normalize fluctuations to these expenses?

A. Yes.

Q. Does RUCO agree with the normalization of these expenses?

A. No. The Company requested an increase of $355,543 that is primarily driven by an insurance deductible amount of $1 million that relates to a pedestrian truck accident that occurred in 2013.

Q. Did the Company request to include this adjustment in the last rate case?

A. Yes. Staff's witness Mr. Ralph Smith, addressed this problem in the last rate case. RUCO has the same concerns as in the last rate case, which are as follows:

- That being the accident occurred in 2013 expense and is tantamount to retro-active ratemaking.
- Nonrecurring and unusual.
- The Company has not demonstrated that it is normal for a $1 million expense to occur, or for it to occur approximately every three years.

Q. Historically what has been the costs in account 78100 injury and damages?

A. The historical the costs are as follows:

2010	$0
2011	$0
2012	$10,000
2013	$1,071,000
2014	$0

Q. Did RUCO question the $1,071,000 in injury and damages?

A. Yes, in response to RUCO data request 6.01, the Company stated the $1,071,000 was comprised of the following:

1. $1 Million claim reserve for a lawsuit in which the owner and tenant of a warehouse in Nogales allege a fire at their warehouse on 05-15-2013 was caused by an improperly installed dusk to dawn light that allegedly sparked causing the fire. On 07-24-2015 a jury returned a verdict in favor of UNS Electric with zero negligence and zero damages due. In July, 2015 the claim reserve was reversed.

2. $30,000 claim reserve for a pending lawsuit in which the plaintiff alleges UNS Electric was negligent for an auto accident on 05-15-2012 in Kingman, AZ resulting in injuries to the plaintiff.

3. $41,000 claim payment to the US Forest Service for firefighting expenses from a 2008 fire in Santa Cruz County allegedly caused by a downed power line.

Q. Does RUCO believe any of these amounts should be included in the test year?

A. No. The largest driver of the injury and expenses - the $1 million claim has been settled in the Company's favor. However, the Company still wants to recovery this amount from ratepayers. A claim reserve is not relevant because it is not known and measureable. The only claim that could be relevant is the $41,000 claim payment to the US Forest Service. However RUCO does not see a pattern of the Company paying the US Forest Service $41,000 every year, as this is a non-reoccurring and unusual expense.

Q. What is RUCO's recommendation?

A. RUCO recommends that that the $1,071,000 be removed, and a three year average be applied. RUCO's adjustment reduces other operations and maintenance expense by $343,815, as shown on schedule JMM-16.

Operating Income Adjustment No. 8 – Edison Electric Institute ("EEI") Dues

Q. Did the Company remove any EEI Utility Air Regulation Group ("UARG") membership dues?

A. No.

Q. Whose interest does UARG represents?

A. UARG represents the interest of electric generators such as UNS and TEP in Environmental Protection Agency ("EPA") rulemaking procedures and litigation procedures against the EPA. Membership in UARG is voluntary. These issues are purely-political and are not necessary for the provision of utility services. Further, without a listing of activities that UARG allocates by function or category (e.g. advertising) it is impossible to determine which expense costs may be allowable or disallowable therefore the entire amount should be removed.

Q. What is RUCO's recommendation regarding EEI – UARG Membership Dues?

A. RUCO recommends removing $14,523 (i.e. $15,123 x .9603 ACC jurisdiction ratio) of EEI – UARG Membership Dues.

Q. Has the Company already reduced the $3,500 it paid in EEI – Regular Membership Dues?

A. Yes. Based on a letter from EEI, the Company stated its actual lobbying expenses were 6.20 percent for 2014 and estimates lobbying expense for 2015 to be 7.00 percent. Therefore, the Company reduced this expense by 208 (i.e. $3,500 x 6.20 percent x .9603 ACC jurisdiction ratio).

Q. What has the Commission recommended in prior Decisions?

A. The Commission recommended a reduction in EEI dues of 49.93 percent in Decision No. 71914 and 70860.

Q. How was this percentage determined?

A. The percentage was determined using the following NARUC Operating Expense Categories:[2]

NARUC Operating Expense Categories	Percentage of Dues
Legislative Advocacy	20.38%
Regulatory Advocacy	16.49%
Advertising	1.67%
Marketing	3.68%
Public Relations	7.71%
Total Expenses	49.93%

For other expense items see Attachment C.

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[2] Based on the Edison Electric Institute Schedule of Expenses by NARUC Category For Core Dues Activities for the Year Ended December 31, 2005.

Q. Has RUCO updated this information from EEI?

A. Unfortunately RUCO cannot. After 2006, the EEI stopped providing this information. RUCO believes after a series of regulatory partial disallowances of EEI dues by Commissions across the nation, EEI decided not to provide this information to NARUC, which it had previously done for at least a decade.

Q. So in other words, the letter the Company received from EEI only addresses one expense category- Legislative Advocacy?

A. Yes. The letter provides no information on the other eight categories or 93.80 percent of EEI's other budgeted expenses.

Q. Please comment further.

A. Since it is apparent that the percentage of Legislative Advocacy expense has dropped from 20.38 percent to 6.20 percent, it only makes sense that most of these costs have been shifted elsewhere, but RUCO does not know because EEI does not supply an expense report anymore that has these details.

Q. What is RUCO's recommendation?

A. RUCO recommends a disallowance percentage of 35.75 percent based on ***the best information available***, as follows:

NARUC Operating Expense Categories	Percentage of Dues
Legislative Advocacy	6.20%
Regulatory Advocacy	16.49%
Advertising	1.67%
Marketing	3.68%
Public Relations	7.71%
Total Expenses	35.75%

This results in an additional disallowance of EEI membership dues of 29.55 percent (i.e. 35.75 – 6.20) or $994 (i.e. $3,500 x 29.55 percent x .9603 ACC jurisdiction ratio).

RUCO, recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its membership expenses. Further, the Commission should send a strong message to the Company that ***all*** EEI membership may be disallowed in the future if this information is not provided.

In summary, RUCO recommends a total disallowance of EEI dues in the amount of $15,517 (i.e. 14,523 + 994), as shown in RUCO schedule JMM-17.

Operating Income Adjustment No. 9 – Rate Case Expense

Q. What has the Company requested as an estimate of rate case expense to be authorized in this case?

A. The Company in its initial filing had requested an estimated $400,000 in rate case expense to be amortized over 3 years. Subsequently, the Company in response to Staff data request # 4.01 has revised its estimate upwards to $770,000. Almost double the original estimate.

Q. What was the amount of Rate Case Expense requested and authorized by the Commission in prior cases?

A. In Decision No. 70360 (dated May 27, 2008), the Company requested $600,000 in estimated rate case expense and was authorized $300,000. In Decision No. 71914 (dated September 30, 2010), the Company requested $500,000 in estimated rate case expense and was authorized $300,000. In Decision No. 74235 (dated December 31, 2013), the Company requested $500,00 in estimated rate case expense, the parties settled in that case, for $300,000.

Q. When asked, did the Company explain the difference between this case and the prior case that would necessitate an increase in rate case expense?

A. Yes. The Company in response to Staff data request 4.02 stated that "In this case, the Company is seeking recovery for outside labor resulting from a Marginal Cost Study and rate design, which it did not seek in the last three rate cases. The Company is requesting recovery of those costs in this filing. In the last UNS Electric rate case (Decision No. 74235, dated December

31, 2013) the Company did not perform a depreciation study and therefore did not incur any incremental costs."

Q. What does RUCO recommend as a reasonable allowance for rate case expense in this proceeding?

A. RUCO recommends $350,000 in rate case expense to be normalized over three years, as shown is RUCO Schedule JMM-18.

Operating Income Adjustment No. 10 – Interest Synchronization

Q. Please explain interest synchronization?

A. An interest synchronization adjustment is done to insure that the revenue requirement reflects the tax savings generated by the interest component of the revenue requirement. The interest synchronization expense is calculated by multiplying the rate base by the weighted average cost of debt. The combined state and federal income tax rates are then applied to the resulting interest deduction difference to determine the income tax expense adjustment.

Q. Has RUCO made an adjustment for interest synchronization?

A. Yes. Since the Company's rate base differs from RUCO's recommended rate base, an adjustment was required. RUCO's adjustment increases interest synchronization by $58,805, as shown is RUCO Schedule JMM-19.

Operating Income Adjustment No. 11 – Income Tax Expense

Q. Has RUCO adjusted income taxes as a result of its adjustments, mentioned above?

A. Yes. RUCO applied the statutory state and federal income tax rates to RUCO's taxable income. As a result, RUCO has increased Income tax expenses for the adjusted test year by $1,526,666, as shown in RUCO schedule JMM-20.

VI. OTHER ISSUES

Arizona Property Tax Deferral

Q. Is the Company also asking for a property tax deferral in this case?

A. Yes. The Company is asking for a two part property tax deferral. 1) To account for 100% of the Arizona property taxes above or below the test year level caused by changes in the composite property tax rate. 2) To account for changes in the Gila River property tax values, and defer all costs associated with appealing Gila River property values. In order to separate the issues RUCO will first address the Arizona property tax deferral first, and then the Arizona property tax deferral related to the Gila River property tax values and related legal costs involved with appealing the Department of Revenue Decision. Each of which deserves separate consideration.

Q. What is the Company's basis for the first part of its request?

A. The Company claims the overall property values on which property taxes are assessed have gone down in Mohave and Santa Cruz counties. At the same time, the property tax rates have also increased in Mohave and Santa Cruz Counties. The Company then states there is a correlation between the two, as the overall property value declines, property taxes must increase. The Company also cites Decision No. 73183 (dated May 24, 2012) to support its decision.

Q. Please comment?

A. I agree that the decline in property values may be one factor for the increase in the property tax rate. However, I do not believe it is the only one. Property taxes are generally used to fund the county's general fund. For example, employee positions, reductions in expenses, and sales tax revenues that are also considered when developing a County budget. I have included the FY 2015 Budget Review of Arizona Counties issued by the Arizona Tax Research Association (see Attachment D), which shows all facts related to county budgets and property taxes not just the selected information provided by the Company. In fact on page 5 of this budget review the Net Assessed Values did drop by 2.9 percent. However, the tax rate stayed the same for Mohave County (see page 33 of this budget review). This disproves the Company's property tax theory.

Q. Please address the Company's assertion that Arizona Public Service Company ("APS") had property tax deferral approved by the Commission in Decision No. 73183 (May 24, 2012), and the same logic should apply to the Company?

A. Decision No. 73183 was the result of a settlement agreement.

Q. What is a settlement agreement?

A. It is a negotiation between the parties, in which there is give and take on the respective parties' positions.

Q. Please elaborate.

A. In the APS case as a result of a settlement between the parties, APS reduced its return on equity by 100 basis points. In addition, APS agreed to a stay out for four years.

As Staff stated in its opening brief in which they cited APS witness Guldner, "APS is concerned that its property tax rate and related expenses could increase significantly during the course of the proposed 4 year stay-out, as it has over the past few years."[3]

Q. Is the property tax deferral approved by the Commission in Decision No. 73183 the same as what the Company is proposing here?

A. No. The only similarity is they are both requests for property tax deferrals. As was stated in Decision No. 73183, referring to Section XII. Cost Deferral Related to Changes in Arizona Property Tax Rate – "This Section allows APS to defer without interest for future recovery: 25 percent of the prorated property tax rate increase in 2012, 50 percent in 2013, and 75 percent each year thereafter, and 100 percent of all property tax rate decreases; recovery will begin after the next general rate case with recovery of a positive balance

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[3] See Staff Opening Brief in Docket No. E-01345A-11-0224 (dated February 29, 2012).

spread over 10 years and a negative balance over three years; and the signatories may review the deferrals for reasonableness and prudence."[4]

Clearly, the provisions in the APS property tax deferral were more palatable to ratepayers, then what the Company has proposed in this case.

Q. Has the Company stated that it is willing to reduce its Cost of Equity by 100 basis points or has it agreed to a four year stay-out provision?

A. No.

Q. What is RUCO's recommendation?

A. Property tax is just one type of expense that may go up or down between rate cases. The risk that the Company faces is that expenses may increase or decrease between rate cases is reflected in the Company's cost of capital, as it has always been done through traditional ratemaking. There is nothing extra ordinary about the Company's request for a deferral of property taxes in this case, other than APS received one. Further to allow such treatment would be tantamount to single issue ratemaking. RUCO recommends denial of the Company's proposed deferral of property taxes.

Gila River Property Tax Deferral

Q. Please respond to the Company's second component of its proposed tax deferral.

A. The Company states that it disagrees with the Arizona Department of Revenues ("ADOR") assessment of its Gila River Power Plant full cash

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[4] See page 15, line 20 of Decision No. 73183.

value estimate of $50 million, while the Company estimates the value to be approximately $29 million.

Q. Would this save ratepayers money in the longer term on property taxes if the appeal is successful?

A. Yes. However, this would also save the Company's shareholders money in the long term. In exchange, the Company wants to transfer the risk from the shareholders to ratepayers. If the Company loses the appeal, ratepayers are responsible for the legal bill.

Q. What does RUCO recommend?

A. RUCO recommends a 50/50 sharing between shareholders and ratepayers in its appeal of the Arizona Department of Revenues ("ADOR") assessment of its Gila River Power Plant. RUCO also recommends a reasonable cap be placed on legal expenses. Once this level is exceeded, the Company shareholders should bear any extra costs. If the Company wins, it is my understanding, although I am not an attorney, that ADOR would have to pay the Company's legal expenses and if the Company prevails, in which case the Company would need to refund half of this money to ratepayers.

Gila River One Time Purchased Power Fuel Adjustment Clause ("PPFAC") Credit

Q. Please explain the Company's proposed one time PPFAC credit?

A. Based on page 6 of Company's witness Dallas Dukes testimony he states "UNS Electric is proposing a one-year credit to the purchased power and fuel adjustment clause ("PPFAC") to collect the deferred savings accrued as a result of' the Deferred Accounting Order related to the acquisition of Gila River (estimated at $9.3 million). As a result of these factors, UNS Electric's request would decrease revenue by approximately $5.8 million, or 3.6%, in the first year after new rates take effect. In year two, after the deferred savings are fully credited, the Company's revenue would rise to a level that represents an increase of approximately $3.5 million, or 2.1%, over test year adjusted retail revenue."

Q. Does RUCO agree with the Company's proposal?

A. RUCO agrees that the Company should credit back deferred savings to ratepayers, but would recommend the deferred savings be credited back to ratepayers over a three year period.

Q. Why does RUCO believe the deferred savings should be credited back to ratepayers over a three year period?

A. RUCO believes a normalized approach over three years is preferable to one year. This sends the proper price signal to ratepayers, so that ratepayers are not confused when they get a decrease in the first year and then an increase in the second year. RUCO recommends the deferred savings accrued as a result of' the Deferred Accounting Order related to the acquisition of Gila River be credited back to ratepayers over a three year period through the PPFAC.

Other Changes to the PPFAC

Q. Has the Company asked to have its PPFAC modified?

A. Yes. On page 7 of Company witness Craig A. Jones states the following:

"Regarding the PPFAC, the Company proposes a single percentage-based adjustment applicable to all rate classes and based on the monthly change in total annual fuel cost compared to the annual fuel cost approved in this proceeding - while also changing the rate band to 1% and adding a Base Rate Annual Adjustment."

Q. Does RUCO agree with the Company's proposed adjustments?

A. No. RUCO has concerns that under the single percentage-based approach, this may shift costs from one rate class to another. The current 0.83 percent band reduces the impact of the PPFAC to ratepayers. The Base Rate Annual Adjustment also exposes the ratepayers to more risk. RUCO recommends that the current PPFAC not be modified.

Lost Fixed Cost Recovery ("LFCR") Mechanism

Q. Has the Company asked to have its LFCR mechanism modified?

A. Yes. On page 7 of Company's witness Craig A. Jones testimony he states, "For the LFCR, the Company proposes to allow recovery of lost fixed costs attributable to generation and the full recovery of lost demand revenues."

Q. What has been RUCO's position in the past regarding the LFCR, in this case and in other cases?

A. RUCO has agreed in the past not to oppose the LFCR as long as the LFCR provided an opt-out provision for ratepayers. RUCO has never said the LFCR qualifies as a legal adjustor mechanism. RUCO did not oppose the LFCR as part of the previous settlements because the opt-out provision provided ratepayers with an undisputed legal option to address the Company's fixed-cost concerns.

Q. With the advent of the recent Court of Appeals decision regarding the System Improvement Benefit ("SIB") Mechanism, has RUCO changed its position on the LFCR?

A. No. RUCO is reviewing the legality of the LFCR in light of the Court's opinion.

Q. Does your silence on any issue in this rate filing preclude you from addressing these issues in future testimony?

A. No, it does not.

Q. Does this conclude your direct testimony?

A. Yes.

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

TABLE OF CONTENTS TO RUCO's DIRECT SCHEDULES

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

REVENUE REQUIREMENT
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 272,013	$ 439,427	$ 355,720	$ 264,551	$ 425,710	$ 345,131
2							
3	Adjusted Operating Income (Loss)	8,044	8,044	8,044	10,517	10,517	10,517
4							
5	Current Rate Of Return (Line 3 / Line 1)	2.96%	1.83%	2.26%	3.98%	2.47%	3.05%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 22,108	$ 22,108	$ 22,108	$ 18,147	$ 18,147	$ 18,147
8							
9	Weighted Average Cost of Capital	7.67%	7.67%	7.67%	6.61%	6.61%	6.61%
10							
11	Fair Value Adjustment	0.46%	-2.96%	-1.45%	0.25%	-2.35%	-1.35%
12							
13	Required Rate of Return	8.13%	5.03%	6.22%	6.86%	4.26%	5.26%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 14,064	$ 14,064	$ 14,064	7,629	7,629	7,629
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.6084	1.6084	1.6084	1.6084	1.6084	1.6084
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 22,621	$ 22,621	$ 22,621	$ 12,271	$ 12,271	$ 12,271
20							
21	Adjusted Test Year Revenue	$ 148,936	$ 148,936	$ 148,936	$ 152,027	$ 152,027	$ 152,027
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 171,557	$ 171,557	$ 171,557	$ 164,298	$ 164,298	$ 164,298
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	15.19%	15.19%	15.19%	8.07%	8.07%	8.07%
26							
27	Rate Of Return On Common Equity	10.35%	10.35%	10.35%	8.16%	8.16%	8.16%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules JMM-3, JMM-8, and JMM-20
Column (E): Schedule JMM-2, Column (B)
Column (F): Average of Column (D) + Column (E) / 2

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-2

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectibel Revenue	0.34%	0.34%
3	Taxable Income as a Percent	99.66%	99.66%
4	Less: Federal and State Income Taxes	37.48%	37.48%
5	Changes in Net Operating Income	62.17%	62.17%
6	Gross Revenue Conversion Factor	1.6084	1.6084

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-3

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 664,701	$ 1,169,067	$ 916,884	175.88%	$ 664,701	1,169,067	$ 916,884
2	Accumulated Depreciation	(296,962)	(561,910)	(429,436)	189.22%	(296,962)	(561,910)	(429,436)
3	Net Utility Plant In Service	367,739	607,156	487,448		367,739	607,156	487,448
4								
5	Citizens Acquisition Discount	(95,155)	(170,848)	(133,002)	179.55%	(95,155)	(170,848)	(133,002)
6	Less: Accu Amort Citizens Acq Discount	36,098	69,678	52,888	193.02%	36,098	69,678	52,888
7	Net Citizens Acquisition Discount	(59,057)	(101,170)	(80,113)		(59,057)	(101,170)	(80,113)
8								
9	Total Net Utility Plant	308,682	505,987	407,334	163.92%	308,682	505,987	407,334
10								
11	Deductions:							
12	Cust. Advances For Const.	(3,833)	(4,268)	(4,051)	111.35%	(3,833)	(4,268)	(4,051)
13	Customer Deposits	(4,428)	(4,428)	(4,428)	100.00%	(4,428)	(4,428)	(4,428)
14	Other (ITC)	(422)	(422)	(422)	100.00%	(422)	(422)	(422)
15	Acc. Deferred Income Taxes	(35,161)	(64,617)	(49,889)	183.77%	(42,628)	(78,339)	(60,484)
16	Total Deductions	(43,844)	(73,735)	(58,789)		(51,311)	(87,457)	(69,384)
17								
18	Allowance - Working Capital	7,175	7,175	7,175	100.00%	7,180	7,180	7,180
19								
20	Regulatory Assets	-	-	-	100.00%	-	-	-
21								
22	Regulatory Liability	-	-	-	100.00%	-	-	-
23								
24								
25	TOTAL TEST YEAR RATE BASE	$ 272,013	$ 439,427	$ 355,720		$ 264,551	$ 425,710	$ 345,131

References:

Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule JMM-4, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F) / 2

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-4

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL (Shown in Thousands)

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 664,701	-	$ 664,701
2	Accumulated Depreciation	(296,962)	-	(296,962)
3	Net Utility Plant In Service	367,739	-	367,739
4				
5	Citizens Acquisition Discount	(95,155)	-	(95,155)
6	Less: Accu Amort Citizens Acq Discount	36,098	-	36,098
7	Net Citizens Acquisition Discount	(59,057)	-	(59,057)
8				
9	Total Net Utility Plant	308,682	-	308,682
10				
11	Deductions:			
12	Cust. Advances For Const.	$ (3,833)	-	$ (3,833)
13	Customer Deposits	(4,428)	-	(4,428)
14	Other - Investment Tax Credits ("ITC")	(422)	-	(422)
15	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	(7,467)	(42,628)
16	Total Deductions	(43,844)	(7,467)	(51,311)
17				
18	Allowance - Working Capital	7,175	5	7,180
19				
20	Regulatory Assets	-	-	-
21				
22	Regulatory Liability	-	-	-
23				
24				
25	TOTAL OCRB	$ 272,013	$ (7,462)	$ 264,551

Reconciliation to RCN (Thousands of Dollars)

	OCRB	RCN Ratio for ADIT	RCN
Company RCN as Filed			$ 439,427
RUCO ADIT Adjustment #1	$ (7,467)	1.8377	(13,723)
Cash Working Capital	5.429	1.0000	5.429
	$ (7,462)		$ 425,710

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-5

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
(Thousands of Dollars)

		ACC Jurisdiction			
Line No.	DESCRIPTION	(A) Company Adjusted OCRB As Filed	[B] Rate Base Adjustment No. 1 Reverse Net Operating Loss Carry forward Accumulated Deferred Income Tax Offset	(C) Rate Base Adjustment No. 2 Working Capital	(D) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service	664,701	$ -	$ -	$ 664,701
2					
3	Accumulated Depreciation	(296,962)	-	-	$ (296,962)
4	Net Utility Plant in Service	$ 367,739	$ -	$ -	$ 367,739
5					
6	Citizens Acquisition Discount	$ (95,155)	$ -	$ -	$ (95,155)
7	Accumulated Amortization - Citizens Acquisition Discount	36,098	-	-	$ 36,098
8	Net Citizens Acquisition Discount	$ (59,057)	$ -	$ -	$ (59,057)
9					
10	Total Net Utility Plant	$ 308,682	$ -	$ -	$ 308,682
11					
12	Customer Advances for Construction	$ (3,833)	$ -	$ -	$ (3,833)
13					
14	Customer Deposits	(4,428)			(4,428)
15					
16	Other - Investment Tax Credits ("ITC")	(422)			(422)
17					
18	Accumulated Deferred Income Taxes ("ADIT")	(35,161)	(7,467)		(42,628)
19	Total Deductions	$ (43,844)	$ (7,467)	$ -	$ (51,311)
20					
21					
22	Allowance for Working Capital	$ 7,175	$ -	$ 5	$ 7,180
23					
24	Regulatory Assets	-	-	-	-
25					
26	Regulatory Liabilities	-	-	-	-
27					
28	Total Original Cost Rate Base	$ 272,013	$ (7,467)	$ 5	$ 264,551

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RBM-4
Column (D) See RBM-5
Column (E) See Column (B) through (D)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

RATE BASE ADJUSTMENT NO. 1
Reverse Net Operating Loss Carryforward
Accumulated Deferred Income Tax Offset

		(A)	(B)	(C)
Line No.	DESCRIPTION	Company Proposed	RUCO Adjustment	RUCO As Adjusted
1	Accumulated Deferred Taxes	$ (35,161,108)	$ (7,467,062)	$ (42,628,170)

ADIT NOLC Offset	$ (7,819,101)
ACC Jurisdictional Factor	0.9550
	$ (7,467,062)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-7

ALLOWANCE FOR WORKING CAPITAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY ADUSTED TEST YEAR AS FILED	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days	(E) Exp Lag Days	(F) Net Lag Days	(G) Lead Lag Factor	(H) Cash Working Capital Requiredments
1	**OPERATING EXPENSES**								
2	Non-Cash Expenses:								
3	Bad Debts Expense	$ 506	-	$ 506	-		-		-
4	Depreciation	11,406	-	11,406			-		-
5	Amortization	(3,629)	(17)	(3,646)			-		-
6	Deferred Income Taxes	4,627	-	4,627			-		-
7	Total Non-Cash Expenses	$ 12,909	(17)	12,892					-
8									
9	Other Operating Expenses:								
10	Salaries & Wages	$ 4,616	-	$ 4,616	35.59	23.33	12.26	0.0336	155
11	Incentive Pay	329	(216)	113	35.59	267.00	(231.41)	(0.6340)	(72)
12	Purchased Power	62,965	-	62,965	35.59	33.79	1.80	0.0049	309
13	Transmission Other	9,014	-	9,014	35.59	40.67	(5.08)	(0.0139)	(125)
14	Meter Reading	574	-	574	35.59	33.67	1.92	0.0053	3
15	Customer Records & Coll Exp	1,169	-	1,169	35.59	34.94	0.65	0.0018	2
16	Office Supplies and Expenses	1,005	(16)	989	35.59	50.89	(15.30)	(0.0419)	(41)
17	Injuries and Damages	750	(414)	336	35.59	70.52	(34.93)	(0.0957)	(32)
18	Pensions and Benefits	1,960	(306)	1,654	35.59	51.37	(15.78)	(0.0432)	(71)
19	Support Services	6,059	-	6,059	35.59	44.77	(9.18)	(0.0252)	(153)
20	Property Taxes	6,733	-	6,733	35.59	212.00	(176.41)	(0.4820)	(3,245)
21	Payroll Taxes	376	-	376	35.59	12.00	23.59	0.0646	24
22	Current Income Taxes	-	-	-	35.59	-	35.59	0.0975	-
23	Interest on Customer Deposits	7	-	7	35.59	182.50	(146.91)	(0.4025)	(3)
24	Other O&M Expenses	25,050	-	35,762	35.59	41.21	(5.62)	(0.0154)	(551)
25	Total Other Operating Exp.	$ 120,607	(952)	$ 130,367					
26									
27	Total Operating Expenses	$ 133,516	$ (968)	$ 143,259					$ (3,801)
28									
29	Other Cash Working Capital Elements:								
30	Interest on Long-Term Debt	7,859	-	7,859	35.59	89.5	$ (53.91)	$ (0.1477)	(1,161)
31	Rev. Taxes and Assessments	11,717	-	11,717	35.59	49.43	$ (13.84)	$ (0.0379)	(444)
32									
33		$ 19,576	$ -	$ 19,576					$ (1,605)
34									
35	TOTAL CASH WORKING CAPITAL	$ 166,001		$ 175,728					
36									
37									
38	Pro Fc Pro Forma Operating Expenses - Excluding Income Taxes	$ 128,889		$ 138,633					
39	Less: ι Less: Other O&M	103,839		102,871					
40		$ 25,050		$ 35,762					

	Shown in Thousands
Total RUCO	$ (5,405,605)
Total Company	$ (5,431,223)
Cash Working Capital Adjustment With ACC Jurisdictioanl Ratio .95717	$ 24,521
Pre-paid D&O Insurance Adjustment With ACC Jurisdictioanl Ratio .95328	$ (19,092)
Total Adjustment	$ 5,429

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53 References:
54 Column (A): - Company Schedule B-5
55 Column (B): RUCO Operating Income Adjustments
56 Column (C): Column (A) + (B)
57 Column (D): Company Schedule B-5
58 Column (E): Company Schedule B-5
59 Column (F): Column (D) - Column (E)
60 Column (G): Column (E)/365

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-8

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO
(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'D
1	Operating Revenues:			
2	Electric Retail Revenues	$ 147,107	$ 3,091	$ 150,197
3	Sales for Resale	-	-	-
4	Other Operating Revenue	1,829	-	1,829
5				-
6	TOTAL OPERATING REVENUES	148,936	3,091	152,027
7				
8	Operating Expenses:			
9	Fuel, Purchased Power and Trans	77,522	-	77,522
10	Other Operations and Maintenance Exp	42,870	(968)	41,901
11	Depreciation and Amortization	13,060	-	13,060
12	Taxes Other than Income Taxes	6,149	-	6,149
13	Income Taxes	1,291	1,585	2,877
14	Rounding Differences	-	-	-
15	TOTAL OPERATING EXPENSES	140,892	617	141,509
16				
17	OPERATING INCOME (LOSS)	$ 8,044	$ 2,473	$ 10,517

References:
Column (A): Company Schedule C-1
Column (B): RUCO Schedule 9
Column (C): Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-9
Page 1 of 2

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) Adj. 1 Current Charges Authorized by the Commission not applied JMM-10	(C) Adj. 2 Not Used JMM-11	(D) Adj. 3 Normalize Medical nd Dental Expense JMM-12	(E) Adj. 4 Directors & Officers Ins. JMM-13	(F) Adj. 5 Vellness, Employee, Spot Award JMM-14
1	Operating Revenues:						
2	Electric Retail Revenues	$ 147,107	$ 3,091	$ -	$ -	$ -	$ -
3	Sales for Resale	-	-	-	-	-	-
4	Other Operating Revenue	1,829	-	-	-	-	-
5				-			
6	TOTAL OPERATING REVENUE	148,936	3,091	-	-	-	-
7							
8	Operating Expenses:						
9	Fuel, Purchased Power and Tr	77,522	-	-	-	-	-
10	Other Operations and Mainten	42,870	-	-	(306)	(70)	(47)
11	Depreciation and Amortization	13,060	-	-	-	-	-
12	Taxes Other than Income Taxe	6,149	-	-	-	-	-
13	Income Taxes	1,291	-	-	-	-	-
14	Rounding Differences	-	-	-	-	-	-
15	TOTAL OPERATING EXPENSE	140,892	-	-	(306)	(70)	(47)
16							
17	OPERATING INCOME (LOSS)	$ 8,044	$ 3,091 $ -	$ -	$ 306	$ 70	$ 47

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

(Thousands of Dollars)

(G) Adj. 6 PEP Expense JMM-15	(H) Adj. 7 Injuries and Damages JMM-16	(I) Adj. 8 EEI Dues JMM-17	(J) Adj. 9 Rate Case Expense JMM-18	(k) Adj. 10 Interest Synchronization JMM-19	(L) Adj. 11 Income Tax JMM-20	(M) RUCO as Recommended
$ -	$ -	$ -	$ -	$ -	$ -	$ 150,197
-	-	-	-	-	-	-
-	-	-	-	-	-	1,829
-	-	-	-	-	-	152,027
-	-	-	-	-	-	$ 77,522
(170)	(344)	(16)	(17)		-	41,901
-	-	-	-	-	-	13,060
-	-	-	-	-	-	6,149
-	-	-	-	59	1,527	2,877
-	-	-	-	-	-	-
(170)	(344)	(16)	(17)	59	1,527	141,509
$ 170	$ 344	$ 16	$ 17	$ (59)	$ (1,527)	$ 10,517

OPERATING INCOME ADJUSTMENT NO. 1
CURRENT CHARGES AUTHORIZED BY THE COMMISSION NOT APPLIED TO TEST YEAR BILLING DETERMINANTS

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Electric Retail Revenues	$ 147,106,730	$ 3,090,705	$ 150,197,434
2				
3				

4 RUCO's Calculation

5

6

7		RUCO's Calculation			Company's Calculation			
8	Customer Class	Current Rates	Test Year Billing Determinents	Adjusted Test Year Revenues	Current Rates	Test Year Billing Determinents	Adjusted Test Year Revenues	Difference
9								
10	5713 LARGE GENERAL SERVICE							
11	Basic Service Charge	$ 50.000000	16,092	$ 804,600	$ 50.000000	16,092	$ 804,600	
12	Demand Charge, per kW	$ 12.810000	1,394,255	$ 17,860,410	$ 12.810000	1,394,255	$ 17,860,410	
13	Energy Charge, per kWh	$ 0.005470	445,782,493	$ 2,438,430	$ 0.005470	445,782,493	$ 2,438,430	
14	TCA, per kW	$ 0.432900	0	$ -	$ 0.432900	0	$ -	
15	Margin Total							
16								
17	Base Power	$ 0.056603	445,782,493	$ 25,232,626	$ 0.048440	445,782,493	$ 21,593,704	
18	PPFAC Revenue	Varies by Month			Varies by Month			
19	Total Fuel Revenue							
20								
21	Total Large General Service			$ 46,336,067			$ 42,697,144	$ 3,638,922
22								
23								
24	5771 LARGE GENERAL SERVICE TIME OF USE							
25	Basic Service Charge	$ 52.000000	96	$ 4,992	$ 52.0000	96	$ 4,992	
26	Demand Charge, per kW	$ 12.810000	16,192	$ 207,417	$ 12.8100	16,192	$ 207,417	
27	Energy Charge, per kWh	$ 0.005470	7,718,956	$ 42,223	$ 0.0055	7,718,956	$ 42,223	
28	TCA, per kW	$ 0.432900	0	$ -	$ 0.4329	0	$ -	
29	Margin Total							
30								
31	Base Power							
32	Summer On-peak	$ 0.114886	728,854	$ 83,735	$ 0.1099	728,854	$ 80,101	
33	Summer Off-peak	$ 0.039886	2,959,583	$ 118,046	$ 0.0335	2,959,583	$ 99,146	
34	Winter On-peak	$ 0.114886	907,877	$ 104,302	$ 0.0899	907,877	$ 81,618	
35	Winter Off-peak	$ 0.026168	3,122,643	$ 81,713	$ 0.0316	3,122,643	$ 98,676	
36	PPFAC Revenue	Varies by Month			Varies by Month			
37	Total Fuel Revenue							
38								
39	Total Large General Service TOU			$ 642,429			$ 614,173	$ 28,256

40								
41								
42	5709 LARGE POWER SERVICE 3<69 kV							
43	Basic Service Charge	$ 1,200.000000	84	$ 100,800	$ 1,200.000000	84	$ 100,800	
44	Demand Charge, per kW	$ 22.000000	125,432	$ 2,759,504	$ 22.000000	125,432	$ 2,759,504	
45	Power Factor Adjustment			$ 94,842			$ 94,842	
46	Energy Charge, per kWh	$ 0.000462	58,092,107	$ 26,839	$ 0.000462	58,092,107	$ 26,839	
47	Primary Discount			$ (20,808)			$ (20,808)	
48	TCA, per kW	$ 0.432900	0	$ -	$ 0.432900	0	$ -	
49	Margin Total							
50								
51	Base Power	$ 0.041880	58,092,107	$ 2,432,897	$ 0.048400	58,092,107	$ 2,811,658	
52	PPFAC Revenue	Varies by Month			Varies by Month			
53	Total Fuel Revenue							
54								
55	Total Large Power Service Distribution			$ 5,394,074			$ 5,772,835	$ (378,761)
56								
57	LARGE POWER SERVICE 3 TOU <69 kV							
58	Basic Service Charge	$ 1,200.000000	24	$ 28,800	$ 1,200.000000	24	$ 28,800	
59	Demand Charge, per kW	$ 22.000000	33,511	$ 737,242	$ 22.000000	33,511	$ 737,242	
60	Power Factor Adjustment			79,046			79,046	
61	Energy Charge, per kWh	$ 0.000462	15,418,264	$ 7,123	$ 0.000462	15,418,264	$ 7,123	
62	TCA, per kW	$ 0.432900	0	$ -	$ 0.432900	0	$ -	
63	Margin Total							
64								
65	Base Power							
66	Summer On-peak	$ 0.123580	1,259,777	$ 155,683	$ 0.145510	1,259,777	$ 183,310	
67	Summer Off-peak	$ 0.024716	6,623,822	$ 163,714	$ 0.034510	6,623,822	$ 228,588	
68	Winter On-peak	$ 0.093880	1,200,529	$ 112,706	$ 0.124510	1,200,529	$ 149,478	
69	Winter Off-peak	$ 0.022105	6,334,135	$ 140,016	$ 0.032910	6,334,135	$ 208,456	
70	PPFAC Revenue	Varies by Month			Varies by Month			
71	Total Fuel Revenue							
72								
73	Total Large Power Service Distribution TOU			$ 1,424,331			$ 1,622,044	$ (197,713)
74								
75	RUCO Adjustment							$ 3,090,705

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-11

OPERATING INCOME ADJUSTMENT NO. 2
NOT USED

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1		$ -	$ -	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-12

OPERATING INCOME ADJUSTMENT NO. 3
MEDICAL AND DENTAL EXPENSE NORMALIZATION

Line No.	DESCRIPTION		(A) COMPANY PROPOSED		(B) RUCO ADJUSTMENT		(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor		(F) ACC Juridictional RUCO ADJUSTMENT
1	Medical Expense	$	2,205,353	$	(329,800)	$	1,875,553	0.9603	$	(316,694)
2	Dental Expense		82,709		11,295		94,004	0.9603	$	10,846
3	Total	$	2,288,062	$	(318,505)	$	1,969,557	0.9603	$	(305,848)
4										
5	RUCO's Calculation:									
6	Year		Medical Expense Amount							
7	2014	$	2,205,353							
8	2013		1,863,496							
9	2012		1,557,810							
10	Three Year Average	$	1,875,553							
11										
12	RUCO's Calculation:									
13	Year		Dental Expense Amount							
14	2014	$	82,709							
15	2013		92,243							
16	2012		107,060							
17	Three Year Average	$	94,004							

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-13

OPERATING INCOME ADJUSTMENT NO. 4
OFFICERS AND DIRECTORS INSURANCE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(D) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) ACC Juridictional RUCO ADJUSTMENT
1	Officers and Directors Liability Insurance	$ 145,954	$ (72,977)	$ 72,977	0.9603	$ (70,077)
2						
3	RUCO's Calculation:					
4	Company Proposed	$ 145,954				
5	Split between Ratepayers and Shareholder	50%				
6	RUCO Adjustment - Total Company	$ 72,977				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

OPERATING INCOME ADJUSTMENT NO. 5
WELLNESS INCENTIVE PROGRAM, EMPLOYEE RECOGNITION, AND SPOT AWARD

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	Wellnes Incentive Program	$ 15,738	$ (15,738)	$ -	0.9603	$ (15,113)
2	Employee Recognition	10,740	(10,740)	-	0.9603	(10,313)
3	Spot Awards	22,000	(22,000)	-	0.9603	(21,126)
4	Total	$ 48,478	$ (48,478)	$ -	0.9603	(46,551)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-15

OPERATING INCOME ADJUSTMENT NO. 6
UNS SHORT-TERM INCENTIVE PROGRAM

Line No.	DESCRIPTION	(A) 2014 Company Total	(B) Company Pro Forma Adjusment	(C) Total COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) ACC Juridictional Factor	(F) RUCO AS ADJUSTED
1	FERC						
2	0581	$ 5,914	$ 2,199	$ 8,113	$ (4,057)	1.0000	$ (4,057)
3	0583	-	4,412	4,412	(2,206)	1.0000	(2,206)
4	0592	-	4,247	4,247	(2,123)	1.0000	(2,123)
5	0593	3,661	5,642	9,302	(4,651)	1.0000	(4,651)
6	0901	13,287	9,402	22,689	(11,344)	1.0000	(11,344)
7	0908	5,962	800	6,763	(3,381)	1.0000	(3,381)
8	0920	116,594	140,893	257,487	(128,743)	0.9603	(123,628)
10	O&M Expense	$ 145,417	$ 167,595	$ 313,012	$ (156,506)		$ (151,391)
11	0408 FICA Tax	6,054	7,687	13,741	(6,871)	0.9601	(6,597)
12	Total	$ 151,471	$ 175,282	$ 326,753	$ (163,377)		$ (157,988)
	Less: RUCO removal of Company projected costs 12,122 x acc jurisdicition ratio of .9661						$ (11,712)
	Total RUCO adjustment						$ (169,700)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-16

OPERATING INCOME ADJUSTMENT NO. 7
INJURIES AND DAMAGES

Line No.	UNSE Adjustment to Injuries & Damages	(A)	(B)	(C)	(D)
1	**Account Description**	**2012**	**2013**	**2014**	**Average for 3 Years**
2	Workers' Compensation	$ 55,586	$ 44,482	$ 37,493	$ 45,854
3	Workers' Compensation	(32,917)	18,204	(9,696)	(8,136)
4	Injuries & Damages	10,000	1,071,000	-	360,333
5					
6	Total for Three Year Period	$ 32,670	$ 1,133,687	$ 27,797	$ 398,051
7					
8					
9	Company Average for 3 years	$ 398,051	Column (D) Ln 6		
10					
11	Expenses for Test Year	$ 27,797	Column (C) Ln 6		
12					
13	Company Adjustment Using 3 Year Average	$ 370,254	Column (A) Ln 9 - Ln 11		
14					
15	ACC Jurisdictional	96.027%			
16					
17	ACC Jurisdictional Adjustment	$ 355,543	PER COMPANY'S Calculation		
18					
19					
20	**RUCO's Adjustment to Injuries & Damages**				
21					
22	**Account Description**	**2012**	**2013**	**2014**	**Average for 3 Years**
23	Workers' Compensation	$ 55,586	$ 44,482	$ 37,493	$ 45,854
24	Workers' Compensation	(32,917)	18,204	(9,696)	(8,136)
25	Injuries & Damages	10,000	1,071,000	-	360,333
26	RUCO Reduction in Injuries and Damages	-	(1,071,000)	-	(357,000)
27					
28	Total for Three Year Period	$ 32,670	$ 62,687	$ 27,797	$ 41,051
29					
30					
31					
32	RUCO does not believe that the Injuries and damages expense for $1,071,000 incurred at year ending 2013 should be included in the calculation for the the three year period. The expense is extraordinary in nature and should be excluded.				
33					
34					
35	RUCO'S Average for 3 years	$ 41,051	Column (D) Ln 28		
36					
37	Expenses for Test Year	$ 27,797	Column (C) Ln 28		
38					
39	Company Adjustment Using 3 Year Average	$ 13,254	Column (A) Ln 35 + Ln 37		
40					
41	ACC Jurisdictional	96.027%			
42					
43	ACC Jurisdictional Adjustment	$ 11,728	PER RUCO's Calculation		
44					
45					
46	**TOTAL RUCO ADJUSTMENT**	**$ (343,815)**	**Line Column (A) Ln 18 + Column (A) Ln 44**		

References:
Columns (A) through (D) Lines 3 through 18 provided by Company
in UDR 1.01 Workpaper Schedules.

Columns (A) through (D) Lines 21 through 47 RUCO calculations

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-17

OPERATING INCOME ADJUSTMENT NO. 8
EEI DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) COMPANY ADJUSTMENT	(C) COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO ACC JURISDICTIONAL ADJUSTMENT
1	EEI Membership - USWAG	$ 3,500	$ (217)	$ 3,283	$ (1,035)	$ (994)
2	UARG - Membership Dues	15,123	-	15,123	$ (15,123)	$ (14,523)
3	Total Dues Expense	$ 18,623	$ (217)	$ 18,406	$ (16,158)	$ (15,517)

RUCO's Calculation:	
EEI - Membership	$ 3,500
RUCO's Disallowance	0.3575
Amount Disallowed	$ 1,251
ACC Jurisdictional Ratio	0.9603
ACC Jurisdictional Amount	$ 1,202
Reconciliation	
$217 x .9603 Already removed by Company	$ 208
$1,035 (1,251 - 217) x .9603	994
	$ 1,202
UARG Dues $15,123 x .9603	$ 14,523

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO RECOMMENDED	(C) RUCO ADJUSTMENT
1	Rate Case Expense	$ 400,000	$ 350,000	
2	Normalization Years	3	3	
3	Rate Case Expense	$ 133,333	$ 116,667	$ (16,667)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-19

Operating Adjustment No. 10
Interest Synchronization

Line No.	Description	Tax Rate	[A] Company Proposed	[B] RUCO Recommended
1	Adjusted Rate Base		$ 272,013,129	$ 264,551,496
2	Weighted Cost of Debt		2.20%	2.20%
3	Synchronized Interest Deduction		$ 5,979,180	$ 5,815,165
4	Increase (Decrease) in Deductible Interest			$ (164,016)
5	State Income Taxes	5.48%		$ 8,980
6	Federal Taxable Income			$ (155,036)
7	Federal Income Taxes	32.14%		$ 49,825
8	Increase (Decrease) to Income Tax Expense			$ 58,805

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

OPERATING INCOME ADJUSTMENT NO. 11
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenues:		
2	Electric Retail Revenues	$	3,090,705
3	Sales for Resale		-
4	Other Operating Revenue		-
5	Total Operting Revenue	$	3,090,705
6			
7	Operating Expenses:		
8	Fuel, Purchased Power and Trans	$	-
9	Other Operations and Maintenance Exp	$	(968,174)
10	Depreciation and Amortization	$	-
11	Taxes Other than Income Taxes	$	-
12	Pre -Tax Operating Expenses	$	(968,174)
13	Pre -Tax Operating Income	$	4,058,879
14	Income Taxes	$	1,526,666
	Combined Effective Tax Rate from Company's C-3		37.6130%

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

UNS Electric, Inc.
Docket No. E-04204A-15-0142
Test Year Ended December 31, 2014

Schedule JMM-21

COST OF CAPITAL - ORIGINAL COST RATE BASE
Thousands of Dollars

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-term Debt	169,590	-	169,590	47.17%	4.82%	2.27%
2							
3	Common Equity	189,932	-	189,932	52.83%	10.35%	5.47%
4							
5	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
6							
7	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.74%
8							
9							

10 COST OF CAPITAL - FAIR VAUE RATE BASE

11

	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
12-15							
16							
17	Long-term Debt	169,590	$ -	$ 169,590	47.17%	4.66%	2.20%
18							
19	Common Equity	189,932	-	189,932	52.83%	8.35%	4.41%
20							
21	TOTAL CAPITAL	$ 359,522	$ -	$ 359,522	100.00%		
22							
23	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						6.61%
24							
25							
26					Fair Value Incement		0.25%

References:
Column (A): Company Schedule D-1
Column (B): Testimony, RBM
Column (C): Column (A) + Column (B)
Column (D): Column (C), Line Item / Total Capital
Column (E): Testimony, RBM
Column (F): Column (D) X Column (E)

ATTACHMENT A

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

Arizona Corporation Commission
DOCKETED
FEB 22 2013
DOCKETED BY nR

IN THE MATTER OF THE COMMISSION'S GENERIC EVALUATION OF THE REGULATORY IMPACTS FROM THE USE OF NON-TRADITIONAL FINANCING ARRANGEMENTS BY WATER UTILITIES AND THEIR AFFILIATES.

Docket No. W-00000C-06-0149

DECISION NO. 73739

Open Meeting
February 12, 2013
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. On June 15, 2012, a draft policy statement ("Policy Statement") regarding the treatment of income tax expense for tax-pass through entities was filed in this docket for the Commission's consideration.

2. Comments were filed by various interested parties. The Commission's Utilities Division Staff ("Staff") docketed a Staff Report on June 27, 2012 providing Staff's analysis and recommendations for Commission consideration.

3. A revised draft policy statement ("Revised Policy Statement") was docketed on February 11, 2013 and is attached as Attachment 1.

4. During the Commission Open Meeting held on February 12, 2013, the Commission considered the Revised Policy Statement, the Staff Report, and the filed and oral comments provided by interested parties. After deliberation, the Commission voted to adopt the Revised Policy Statement.

. . .

CONCLUSIONS OF LAW

1. The Arizona Corporation Commission is a constitutionally created agency with authority to promulgate orders, rules, and regulations regarding the methodology of establishing the rates charged by public service corporations pursuant to Article XV of the Arizona Constitution and A.R.S. Title 40.

2. It is in the public interest to adopt the attached Revised Policy Statement to guide the ratemaking treatment of income taxes for tax pass-through public service corporations.

ORDER

IT IS THEREFORE ORDERED that the revised policy statement regarding the ratemaking treatment of income tax expense for tax pass-through entities is hereby adopted.

IT IS FURTHER ORDERED that this decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN

COMMISSIONER

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, JODI JERICH, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capital, in the City of Phoenix, this 21st day of February 2013.

JODI JERICH
Executive Director

DISSENT: Brenda Burns

DISSENT: ______________________

SERVICE LIST FOR: DOCKET NO. W-00000C-06-0149

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ATTACHMENT 1

Policy Statement on Income Tax Expense for Tax Pass-Through Entities

Revised 2/8/13

In several recent rate cases,[1] the Arizona Corporation Commission ("Commission") has been asked to impute income tax expense in the cost of service of so-called tax pass-through entities such as limited liability companies, Subchapter S corporations and partnerships. In each of these proceedings, the applicants presented testimony and evidence to the Commission supporting their request for including income tax expense. On the basis of this testimony and evidence, some commissioners expressed interest in reconsidering the income tax issue. In a Staff Meeting held January 12, 2011, the commissioners directed Utilities Division Staff to examine the merits of allowing income tax expense for tax pass-through entities in the generic docket captioned In the Matter of the Commission's Generic Evaluation of the Regulatory Impacts from the Use of Non-traditional Financing Arrangements by Water Utilities and their Affiliates.[2] A workshop was subsequently publicly noticed by Utilities Division Staff and held on March 25, 2011. Various participants in the generic docket made presentations, which were filed with Docket Control, addressing the arguments for and against including income tax expense in the cost of service of tax pass-through entities.

Because some commissioners were interested in reconsidering the question of imputed income tax expense, in early 2011 the Commission began to include an ordering paragraph in its rate case decisions for tax pass-through entities which recognized the possibility that the Commission might change its practice on the issue, and which specified a process for an affected utility to obtain a prospective increase in its revenue requirement through the filing of a petition under A.R.S. § 40-252 in the event the Commission did change its policy on imputed income tax expense. For example, the Commission included the following language in Decision 72177 (February 11, 2011) from the last Sahuarita Water Company rate case:

> IT IS FURTHER ORDERED that in the event the Commission alters its policy to allow S-corporation and LLC entities to impute a hypothetical income tax expense for ratemaking purposes, Sahuarita Water Company, LLC may file a motion to amend this Order prospectively, and Sahuarita Water Company, LLC's authorized revenue requirement hereunder, pursuant to A.R.S. § 40-252, to reflect the change in Commission policy.[3]

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[1] Sunrise Water Co. (Docket No. W-02069A-08-0406), Farmers Water Co. (Docket No. W-01654A-08-0502), Johnson Utilities, LLC (Docket No. WS-02987A-08-0180), Sahuarita Water Company, LLC (Docket No. W-03718A-09-0359), and Pima Utility Company (Docket Nos. W-02199A-11-0329 and W-02199A-11-0330).

[2] Docket W-00000C-06-0149.

[3] Decision 72177 at 45-46.

There are a number of states which allow income tax expense in the cost of service for tax pass-through entities. For example, in Suburban Utility Corporation v. Public Utility Commission of Texas, 652 S.W.2d 358 (1983), the Supreme Court of Texas held that recognition of income tax expense for tax pass-through entities is necessary:

> "The income taxes required to be paid by shareholders of a Subchapter S corporation on a utility's income are inescapable business outlays and are directly comparable with similar corporate taxes which would have been imposed if the utility operations had been carried on by a corporation. Their elimination from cost of service is no less capricious than the excising of salaries paid to a utility's employees would be. We therefore hold that Suburban [a Subchapter S corporation] is entitled to a reasonable cost of service allowance for federal income taxes actually paid by its shareholders on Suburban's taxable income or for taxes it would be required to pay as a conventional corporation, whichever is less."[4]

Based upon the evidence and testimony which has been presented in the recent rate cases before this Commission as well as the generic docket, we are persuaded that a tax pass-through entity should be allowed to recover income tax expense as a part of its cost of service and that its revenue requirement should be grossed up for the effect of income taxes. We are persuaded that the failure to include income tax expense needlessly discriminates against tax pass-through entities and creates an artificial impediment to investment in utility infrastructure. Neither of these outcomes serves the interests of rate payers. Thus, we hereby adopt a new policy which allows imputed income tax expense in the cost of service for limited liability companies, Subchapter S corporations and partnerships. While sole proprietorships are not technically tax pass-through entities, the arguments supporting the inclusion of income tax expense for tax pass-through entities are equally applicable in the case of sole proprietorships. Thus, the policy will apply to sole proprietorships as well as tax pass-through entities.

This new policy will be applied in pending and future rate cases. Also, companies that have been denied recognition of income tax expense in the past may make a filing under A.R.S. § 40-252 to modify the revenue requirement authorized in their most recent rate case order to include income tax expense prospectively from the date of an order of the Commission approving the A.R.S. § 40-252 filing.

We also desire at this time to provide guidance regarding how income tax expense for tax pass-through entities will be calculated in a fair and balanced way. We agree with the Supreme Court of Texas that the income tax expense for a tax pass-through entity should never be greater than it would be if the utility was a stand-alone C Corporation. Accordingly, tax expense will be determined as follows:

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[4] 652 S.W.2d at 364.

1. Identify all taxable persons or entities and all non-taxable entities[5] (if any) which are owners of the tax pass-through entity. If the tax pass-through entity has an owner which is itself a tax pass-through entity, identify all taxable persons or entities and all non-taxable entities (if any) of such tax pass-through owner. Income tax expense shall be permitted based only upon the effective income tax rates of owners which have actual or potential state and federal income tax liability. The owner or owners of a tax pass-through entity shall not be required to submit personal income tax returns to the Commission, but shall submit documentation showing all owners of the tax pass-through entity, the respective ownership percentages of each owner, and the tax status of each owner (i.e., whether the owner is a taxable entity or a non-taxable entity).

2. Identify the tax filing status (ie. Married filing jointly, married filing single, single, etc.) of the individuals and entities from step 1 above.

3. Compute the actual effective income tax rate for each owner of the tax pass-through entity based upon such owner's proportionate share of taxable income at the proposed revenue level using applicable statutory federal and state income tax rates.

4. Calculate a weighted average effective income tax rate for the combined ownership of the tax pass-through entity.

5. Use the weighted average effective income tax rate for calculating the income tax allowance.

6. Also, calculate the income tax allowance (federal and state) for the tax pass-through entity as though it were a stand-alone Subchapter C corporation.

7. The authorized income tax allowance for the tax pass-through entity shall be the lower of: (i) the income tax allowance using the weighted average effective tax rate for the combined ownership calculated using steps 1 through 5 above; and (ii) the income tax allowance assuming the tax pass-through entity is a stand-alone Subchapter C corporation calculated using step 6 above.

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[5] Non-taxable entities are not-for-profit corporations, municipal corporations or other entities which do not have actual or potential state or federal income tax liability.

COMMISSIONERS
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ARIZONA CORPORATION
COMMISSION

February 21, 2013

Re: Policy Statement on Income Tax Expense for Tax Pass-Through Entities
Docket No. W-00000C-06-0149

Dissent by Commissioner Brenda Burns

I have not been persuaded that the Commission's constitutional duty to set "just and reasonable" rates should include the recovery of a utility shareholder's personal income taxes. "Just and reasonable" rates allow a utility to recover the expenses of a utility plus an opportunity to make a fair profit on its investment. Asking ratepayers to pay personal income taxes for shareholders of utilities organized as subchapter "S" corporations or limited liability corporations (LLCs) (aka "pass-through entities") is neither justifiable nor good public policy. Personal income taxes are not a utility expense.

It is my obligation to consider the interests of both the utility and ratepayers. I do not feel this decision strikes the right balance. There are many ways to ensure that utilities receive a fair amount of revenue to cover its prudently incurred expenses but requiring ratepayers to pay a shareholder's personal income taxes is not a proper solution. Therefore, I must dissent.

Currently, all C corporations are treated equally and all pass-through entities are treated equally. Utilities voluntarily organize as pass-through entities or C corporations for a variety of reasons. Evidence has been presented that shows many utilities have chosen to be pass-through entities because of the tax advantages, including avoidance of the 'double-taxation' faced by C corporations.

However, C corporations and pass-through entities are not treated on equal footing because they are fundamentally different from each other. Ratepayers do not reimburse a C corporation's shareholders for their personal income taxes. This policy change requires ratepayers to reimburse shareholders of pass-through entities for their personal income taxes even though no tax was paid by the company itself.

Indeed, there are necessary water industry reforms that the Commission should examine. I am concerned with how water companies can ably deal with issues such as increased expenses, arsenic remediation requirements, under-recovery of authorized revenues, aging infrastructure and needs for new wells. However, this Decision may result in higher rates for many ratepayers but it does little or nothing to address those issues and may even harm the debate on these potential water utility reforms.

While I do believe that utilities must be compensated for just and reasonable expenses I do not believe this Decision sets a policy that does so in a fair manner.

Brenda Burns
Brenda Burns
Commissioner

Decision No. 73739

ORIGINAL

OPEN MEETING AGENDA ITEM

BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONER

IN THE MATTER OF A POLICY STATEMENT ON INCOME TAX EXPENSE FOR TAX PASS THROUGH ENTITIES.

Docket No. W-00000C-06-0149

RUCO'S COMMENTS

The Residential Utility Consumer Office ("RUCO") files these comments in response to the Commission's consideration of a Policy Statement that would change the current policy to allow tax recovery for pass-through entities.

I. INTRODUCTION

RUCO urges the Commission to not change its current policy which excludes the recovery of income taxes to pass-through entities (S Corporations and LLCs). Simply stated, a Commission policy which would allow pass-through entities to recover from ratepayers taxes that these utilities do not pay is bad public policy.

Commissioner Pierce submitted a draft policy statement ("draft policy") to stakeholders on June 15, 2012. The draft policy expressed numerous concerns with the current policy claiming that it "needlessly discriminates against tax pass-through entities and creates an artificial impediment to investment in utility infrastructure. Neither of these outcomes serves the interests of ratepayers." With all due respect each one of these concerns is empty, and changing the current policy would not serve the ratepayer's interests.

Among other things, a change in the current policy will unquestionably raise ratepayer's rates and result in unintended consequences. At a time when the Commission has its hands full dealing with the public perception of its energy efficiency and renewable energy polices, RUCO hopes that the Commission will give serious consideration to the public perception of a new policy that will result in higher rates because ratepayers will be required to pay a utilities taxes that the utility does not pay.

II. THE CURRENT POLICY DOES NOT DISCRIMINATE BECAUSE PASS-THROUGH CORPORATIONS ARE NOT THE SAME AS C CORPORATIONS.

The LLC/S Corporations and the C corporations are two different types of corporate entities for tax purposes and the Commission should not treat them as if they are the same. The LLC and S Corporation do not pay income tax and elect that form of organization to avoid double taxation. The C Corporation does pay income tax and elects that form of organization for other reasons such as avoiding the maximum shareholder requirement of the S corporation. Trying to treat these two different forms of corporate organization the same is as Commissioner Brenda Burns once said "trying to fit a square peg in a round hole".

Ironically, in the draft policy's quest for parity, the result of a policy change will be even more disparity – in both cases the investors would provide capital resulting in utility operating income, but only the C corporation will pay the income taxes on the operating income prior to distributing dividends to its investors who will then pay income taxes on those dividends.

If one were to believe that the current policy “needlessly discriminates”- surely the solution would not be to implement a policy that will “needlessly discriminate” against C corporation shareholders (i.e. C Corp. shareholders do not currently recover their personal income taxes from ratepayers) – two wrongs do not make a right. But more importantly, how is it that the current policy that does not reimburse the S Corporation for income taxes it does not pay by its own election, but does allow recovery to a C corporation for income taxes it does pay discriminate in any way, shape or form? Actually it is the draft policy that would discriminate. Hence, an unintended but very real consequence of the draft policy will be that the C Corporations will request that their shareholder's be reimbursed for the personal income taxes they pay. This will undoubtedly put the Commission in a very tight spot – for how can the Commission then distinguish the two situations?

Another reason why the two are not the same concerns Accumulated Deferred Income Tax (“ADIT”). When a C Corporation comes in for rate relief, there is an ADIT calculation associated with the corporate income tax. ADIT, which typically is booked as a liability, is also a deduction to ratebase. A deduction to ratebase benefits the ratepayers. With S corporations, an ADIT calculation is not necessary since there is no corporate income tax. The Commission's new policy will impute an income tax based on the shareholder's personal income tax which will ignore ADIT[1] as the calculation is made solely for the purpose of ascertaining the shareholder's recovery of personal income tax from ratepayers and not to ascertain corporate income tax liability. Ratepayer's will get the short end of the stick again.

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[1] The ADIT calculation in a newly filed rate case will apply prospectively since a Company will not have collected any income taxes in rates in the past as an S corporation or an LLC. Nonetheless, it still remains a valid concern.

III. THE CURRENT POLICY DOES NOT CREATE AN ARTIFICIAL IMPEDIMENT TO INVEST IN UTILITY INFRASTRUCTURE IN ARIZONA.

The draft policy purports to stimulate growth but there is no evidence that the current policy acts as an impediment to growth. To the contrary, since the 1980s when the Commission established its policy to deny recovery of personal income taxes of shareholders of pass-throughs, there has been an increase in the number of utilities switching to or organizing as pass-throughs. Particularly after the passage of Tax Reform Act of 1986, utilities have chosen to take advantage of the tax benefits afforded by S corporations and LLCs.

Arizona water/wastewater utilities have experienced phenomenal customer growth in the last few decades. The need for additional infrastructure has been a challenge. Additionally, water utilities have had to comply with the federal Safe Drinking Water Act, the Arizona Groundwater Code, and tougher EPA arsenic standards. Arizona's utilities have risen to the challenge and have done so without changing their corporate status. Some utilities, like Pima are built out, so it is difficult to appreciate the argument that allowance of recovery of personal income taxes will incent needed infrastructure when those utilities were able to meet the infrastructure demands when the challenge was the greatest without choosing to change their corporate status.

The Commission's policy will not spur investment in Arizona. The S corporation status allows utilities to avoid double taxation – paying corporate income taxes on revenues and also personal income taxes on the after-tax dividends. It allows start-ups to raise capital and lower their capital needs which even Pima's Senior Vice President and

Chief Financial Officer, Mr. Steven Soriano explained was a benefit in the Pima case.[2] These benefits are the attraction of organizing as an S corporation, not the Commission's policies.

1. THE CONCERN THAT PASS-THROUGHS WILL SWITCH TO C CORPORATIONS AND RATEPAYERS WILL PAY HIGHER TAXES IS ANOTHER EMPTY CONCERN.

Related to the investment argument is the concern that if utility customers do not cover the pass-through shareholders personal tax liability, then the pass-throughs will elect to reorganize as a C corporation. The maximum corporate income tax rate is higher than the maximum individual income tax rate. A C corporation is subject to corporate income tax. The concern is that since the maximum corporate income tax rate is higher than the individual income tax rate, the ratepayers would pay even higher rates if the rates included recovery for corporate income taxes rather the personal income taxes.

A. THE COMMISSION NEED NOT CHANGE ITS POLICY TO ATTRACT INVESTORS.

In the Pima case, former Commissioner Spitzer explained why on the FERC level there was a need to attract investors. Mr. Spitzer noted that the gas pipelines were desperately needed throughout the country, and the investment community had made it clear that they did not want to invest in the C corporations - they wanted to invest in the pass-through corporations. FERC's intent was to encourage investment in desperately needed gas pipelines.

In Arizona, there is a completely different set of circumstances. With many water utilities, such as Pima, the utility is built out so infrastructure investment is not a concern.

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[2] See Direct Testimony of William Rigsby at 6 in Docket No. W-02199A-11-0329.

Second, with FERC the question centered on desperately needed gas pipelines. In Arizona, the concern is water, not gas pipelines, and there is no air of desperation. Finally, there is no evidence that the Commission's current policy has pushed investors to C corporations. In fact, according to Mr. Spitzer, the evidence would indicate otherwise. Mr. Spitzer testified that most new entities are formed as pass-through LLCs. At the time Mr. Spitzer was an Arizona Commissioner, he testified that the ratio was approximately 100 to 1 and has probably gotten larger[3]. When asked if he was aware of any entities organized as a C corporation because of the Commission's policy he testified that he was not aware of any[4].

Mr. Spitzer's testimony is consistent with Staff's witness, Mr. Carlson who also testified that he had no knowledge of utilities converting to C corporations because of the Commission's long standing policy and could not even recall a single entity organized as an S corporation that converted to a C corporation[5]. The concern is unfounded because S Corporations provide the major benefit of avoiding double taxation which remains regardless of the Commission policy. Pima is a prime example of a pass-through utility that has not changed its corporate status since the mid-80s in spite of the Commission's policy because of the tax advantages implicit with its pass-through status.

IV. THE DRAFT POLICY WILL RAISE RATEPAYERS RATES SIGNIFICANTLY.

The effect on ratepayers of the draft policy will be to raise their rates significantly in most cases. At the Commission's Open Meeting held on July 19, 2012, RUCO discussed with the Commission the effect of such a policy. In response to then Commissioner

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[3] See Transcript of Hearing in the Pima case at 186, Docket No. W-02199A-11-0329.

Newman's comments about how such a policy would raise rates, RUCO explained that at that time there were at least three utilities, Johnson, Sahuarita, and Sunrise that were likely waiting to file 252 applications and one utility, Pima, which at that point had a pending rate application seeking pass-through recovery of income taxes[6]. Based on the filings of the four companies, RUCO had determined that a change in policy would have the combined effect on a total of 40,000 customers of over $2,000,000 in increased cost. Moreover, a change in policy will undoubtedly result in requests from other Arizona pass-through Company's for the recovery of income taxes including Saddle brook (4,800 customers), Sunrise, Tonto Creek, and Naco Water and on and on. The draft policy will result in a lot of ratepayers in Arizona seeing their rates increase to allow utilities to recover income taxes those utilities do not even pay.

V. THE DRAFT POLICY IS LIKELY TO HAVE UNINTENDED CONSEQUENCES.

1. INCREASING RATES TO COVER SHAREHOLDERS' PERSONAL INCOME TAX LIABILITY MAY RESULT IN AN UNJUST ENRICHMENT TO SHAREHOLDERS IF NO TAXES ARE ACTUALLY OWED.

As mentioned above, the shareholders of the C Corporation will undoubtedly complain that the new policy discriminates against them. Another unintended consequence concerns the tax imputation. Since shareholders may offset tax liability for income earned with losses from other S corporations or other investments as well as other deductions, credits and exemptions, it is quite possible that monies collected for the shareholders' tax liability will exceed the amount of tax actually owed. For example, a shareholder of a

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[4] See Transcript of Hearing in the Pima case at 186 - 187, Docket No. W-02199A-11-0329.

[5] See Transcript of Hearing in the Pima case at 308, Docket No. W-02199A-11-0329.

[6] Since the Open Meeting Pima's application has been decided and Pima has chosen to wait until the Commission decided its policy before moving forward on this issue – see Decision No. 73573.

profitable S corporation utility who also realized losses from ownership of a real estate development business can apply those losses to offset earnings derived from the utility. Additionally, a shareholder can apply numerous exemptions, deductions and tax credits that are available to the individual taxpayer but not to a corporation. Examples include exemptions for minor children, deductions for health savings accounts, moving expenses, student loan interest, child tax credit, dependent care tax credit, residential energy credits, and retirement savings credit.

The result would be essentially free money for the shareholders paid by the ratepayers who receive no benefit from these payments.

A. IF THE COMMISSION DECIDES TO CHANGE THE POLICY, THE COMMISSION SHOULD IMPUTE TAX RECOVERY BASED ON SHAREHOLDERS ACTUAL INCOME TAX LIABILITY.

There is no manner in which a system could be developed that would guarantee that ratepayers would pay the appropriate amount of income tax. The taxable income for a C corporation is based on the net income from the business. Taxable income for the individual is based on the transfer of income in any number of ways including salaries, interest, dividends, supplemental income, etc. The individual income tax rate will be the same for all of those income sources with no preferential tax treatment for any source in particular. There is no fair way to reconcile the shareholder's personal income tax with a corporate income tax rate that will guarantee that ratepayers will pay an appropriate and fair amount of income tax. As Staff recently acknowledged, about the best we can do is "damage" the ratepayer as little as possible[7].

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[7] See the testimony of Staff's witness, Daryl Carlson in the recent Pima Utilities case. Transcript at 326 – 327.

If the Commission changes the policy, RUCO recommends that the tax imputation be based on the actual taxes paid, and not a theoretical tax amount. The Commission itself argued before the Arizona Court of Appeals in the *Consolidated* case that "The issue of taxes that are actually paid dominates in states which have authorized inclusion of income taxes even for entities that do not directly incur income taxes."[8] The Commission made this argument to show that a theoretical tax allowance would be arbitrary and inappropriate. See attached excerpt of the Commission's Brief in the *Consolidated* case.

RUCO would not recommend that the Commission consider basing the imputation on federal and state statutory income tax rates. In reality, the vast majority of individuals pay an effective tax rate after deductions and adjustments. Their effective tax rate in most cases is always below the statutory rate.

If the Commission approves the draft policy, RUCO would recommend that the Commission adopt Staff's alternative methodology of imputation in Staff's Supplemental Staff Report dated June 27, 2012.

VI. THE CONSTITUTION'S DIRECTIVE TO SET JUST AND REASONABLE RATES PRECLUDES THE INCLUSION OF UTILTIY EXPENSES THAT DO NOT EXIST.

RUCO believes that the Commission is prohibited by the Arizona Constitution from setting rates that include shareholders' personal income tax liability. Neither the S Corporation nor the LLC pays income taxes. Setting rates based on an operating expense that does not exist will not result in just and reasonable rates. The Commission is required to set just and reasonable rates under the Arizona Constitution. Ariz. Const. Art. 15, § 3.

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[8] See Appellee Arizona Corporation Commission's Answering Brief at 29-33, *Consolidated Water Utilities, Ltd. v. Arizona Corp. Com'n*, 178 Ariz. 478, 875 P.2d 137 Ariz.App. Div. 1, 1993, (September 07, 1993), 1 CA-CC 92-0002. The relevant excerpt of the Answering Brief is attached hereto as Attachment 1.

A change in policy will violate Arizona's Constitutional requirement to set just and reasonable rates.

The Arizona Court of Appeals, at the Commission's request has upheld the current policy. *See Consolidated Water Utilities, Ltd. v. Arizona Corp. Com'n*, 178 Ariz. 478, 484, 875 P.2d 137, 143, Ariz.App. Div. 1, 1993 (September 07, 1993). The Arizona Court of Appeals rejected Consolidated's arguments to change the current policy made in the course of several Consolidated cases. *In the Matter of Consolidated Water Utilities*, Docket Nos. E-1009-86-216, E-1009-86-217, E-1009-86-332.) Decision No. 55839 (Docketed January 8, 1988). *In the Matter of Consolidated Water Utilities*, Docket Nos. E-1009-90-115, E-1009-90-116 (decision No. 57666 (docketed December 19, 1991).

It took more than five years, and many battles for the Commission to settle in on the current policy. The Court of Appeals decision made it clear that Arizona is not bound to follow FERC or any state for that matter on the issue. The Court held that the Commission set just and reasonable rates when it excluded recovery of personal tax expense. The Commission, consistent with its prior decisions as well as the Arizona Court of Appeals decision, should not change the current policy.

VII. CONCLUSION

For these and many other reasons, changing the current policy to allow pass-through entities recovery of income tax that these entities do not pay is bad public policy – period.

RESPECTFULLY SUBMITTED this 11th day of February, 2013.

Daniel Pozefsky
Chief Counsel

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ATTACHMENT

COURT OF APPEALS

STATE OF ARIZONA

DIVISION ONE

CONSOLIDATED WATER UTILITIES, LTD., a limited partnership, Appellant,	1 CA-CC 92-0002
v.	CC Case No. E-1009-90-115, E-1009-90-116
ARIZONA CORPORATION COMMISSION, Appellee.	

APPELLEE'S ANSWERING BRIEF

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August 24, 1992

imposed what it recognized to be a hypothetical tax based on its understanding that an actual tax was paid, 412 P.2d at 850. The Suburban court notes that Moyston is the only decision of a court of last resort on the issue. After noting that the Public Utility Commission had recently approved the imputation of federal income tax liability for a Subchapter S utility, the Suburban court held "...that Suburban is entitled to a reasonable cost of service allowance for federal income taxes actually paid by its shareholders on Suburban's taxable income or for taxes it would be required to pay as a conventional corporation, whichever is less." 652 S.W.2d at 363, 364 (emphasis added).

The issue of taxes that are actually paid dominates in states which have authorized inclusion of income taxes even for entities that do not directly incur income taxes. While the Suburban case remains valid law in Texas, its effects have been somewhat mitigated. In Southern Union Gas Company v. Railroad Commission of Texas, 701 S.W.2d 277 (Tex.App. 3 Dist. 1985), the Texas Court of Appeals refined the Suburban doctrine somewhat, noting "...the Commission did not abuse its discretion in disallowing "theoretical" income tax liability for rate making purposes." 701 S.W.2d at 279. The Southern Union decision is cited approvingly by the Texas Supreme Court in Public Utility Commission of Texas v. Houston Lighting & Power Company, 748 S.W.2d 439 (Tex. 1987), in which theoretical income tax liability is also disapproved.

The most recent word on the topic of taxes actually paid is found in Kansas and it is particularly apposite in the current situation. In Greeley Gas Co. v. State Corporation Commission, 807

P.2d 167 (Kan.App. 1991), the Kansas Court of Appeals, while noting that Suburban appeared to still be good law in Texas, affirmed the Kansas Corporation Commission's disallowance of income taxes based on the utility's failure to produce the taxpayers income tax returns to demonstrate what income taxes were actually paid, if any, noting that the individual shareholders particular situation could cause the tax rate to vary across the various tax brackets that exist, 807 P.2d at 169, 170. In the current case, the issue of theoretical income taxes is squarely joined. Appellant asserts that their rebuttal evidence before the Commission provided evidence of an actual income tax obligation, Appellant's opening brief at page 39. Appellant also asserts that the witness upon whose testimony the income tax disallowance was based admitted that he would have allowed income taxes had Appellant been a corporation, Appellant's opening brief at page 33, citing TR. 446.

Appellant fails to do at least two things, however. First, appellant fails to provide clear and satisfactory evidence of income tax amounts actually paid. The testimony cited by appellant indicates a calculation of income tax attributable to the operation of the utility. Without evidence of the actual payments made by the partners, no clear and satisfactory showing of unreasonableness of the Commission's order has been made, *see* Greeley, *supra*. Secondly, in addition to failing to demonstrate the actual amounts paid, appellant has not addressed the theoretical nature of the calculation of income tax it offered. Appellant mentioned the testimony at page 446 of the transcript on the topic of whether the witness would have allowed income taxes if it had been a corporation. Appellant failed to address the

ATTACHMENT B

Large General Service (LGS)

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE

The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE

A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$50.00 per month
Demand Charge:	$12.81 per kW

Energy Charge (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
All kWh	$0.005470	$0.056603	Varies	$0.062073

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75% of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 20 kW.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 7.28 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$ 19.59 per month
Customer Delivery	$ 4.54 per month
Total	$50.00 per month

Demand Charges (per kW) (Unbundled):

Component	Rate
Demand Delivery	$ 7.64
Generation Capacity	$ 3.09
Transmission	$ 2.08

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.002909
Generation	$0.002394
Transmission	$0.000167

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply	$0.056603
PPFAC (see Rider-1 for current rate)	Varies

Large Power Service Time-of-Use (LPS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$1,200.00 per month
Demand Charges:	
Demand Charge (<69 kV Service)	$22.00 per kW per month
Demand Charge (≥69 kV Service)	$17.00 per kW per month

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
On-Peak	$0.000462	$0.123580	Varies	$0.124042
Off-Peak	$0.000462	$0.024716	Varies	$0.025178

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
On-Peak	$0.000462	$0.093880	Varies	$0.094342
Off-Peak	$0.000462	$0.022105	Varies	$0.022567

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.

In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BILLING DEMAND

The monthly billing demand shall be the higher of:

1. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period;
2. one-half the highest measured fifteen minute integrated reading of the demand meter during the off-peak hours;
3. the higher of (1) or (2) above during the preceding eleven (11) months; or
4. the contract capacity or 500 kW, whichever is higher.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 12:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.

2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 184.69 per month
Meter Reading	$ 364.17 per month
Billing & Collection	$ 498.49 per month
Customer Delivery	$ 152.65 per month
Total	$1,200.00 per month

Demand Charge <69kV (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 17.50 per kW
Generation Capacity	$ 2.07 per kW
Transmission	$ 2.43 per kW

Demand Charge ≥69kV (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 12.73 per kW
Generation Capacity	$ 2.07 per kW
Transmission	$ 2.20 per kW

Energy Charge Components (per kWh) (Unbundled):

Summer (May – October)	On-Peak	Off-Peak
Local Delivery	$0.000343	$0.000343
Generation	$0.000100	$0.000100
Transmission	$0.000019	$0.000019

Power Supply Charge (per kWh):

Summer (May – October)	On-Peak	Off-Peak
Base Power Component	$0.123580	$0.024716
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components (per kWh) (Unbundled):

Winter (November – April)	On-Peak	Off-Peak
Local Delivery Energy	$0.000343	$0.000343
Generation	$0.000100	$0.000100
Transmission	$0.000019	$0.000019

Power Supply Charge (per kWh):

Winter (November – April)	On-Peak	Off-Peak
Base Power Component	$0.093880	$0.022105
PPFAC	In accordance with Rider 1 - PPFAC	

Large General Service Time of Use (LGS TOU)

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, temporary, standby or auxiliary service. Customers must stay on this rate for a minimum period of one (1) year.

CHARACTER OF SERVICE

The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE

A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$52.00 per month
Demand Charge:	$12.81 per kW

Energy Charges (per kWh):

Summer (May – October)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
On-Peak	$0.005470	$0.114886	Varies	$0.120356
Off-Peak	$0.005470	$0.039886	Varies	$0.045356

Winter (November – April)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
On-Peak	$0.005470	$0.114886	Varies	$0.120356
Off-Peak	$0.005470	$0.026168	Varies	$0.031638

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75% of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 20 kW.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 5:00 a.m. - 9:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

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BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 7.57 per month
Meter Reading	$ 19.33 per month
Billing & Collection	$ 20.38 per month
Customer Delivery	$ 4.72 per month
Total	$ 52.00 per month

Demand Charge (per kW) (Unbundled):

Component	Rate
Demand Delivery	$ 7.64
Generation Capacity	$ 3.09
Transmission	$ 2.08

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.002909
Generation	$0.002394
Transmission	$0.000167

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply Summer (May – October) On-Peak	$0.114886
Base Power Supply Summer (May – October) Off-Peak	$0.039886
Base Power Supply Winter (November – April) On-Peak	$0.114886
Base Power Supply Winter (November – April) Off-Peak	$0.026168
PPFAC (see Rider -1 for current rate)	Varies

Large Power Service (LPS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$1,200.00 per month
Demand Charges:	
Demand Charge (<69 kV Service)	$22.00 per kW per month
Demand Charge (≥69 kV Service)	$17.00 per kW per month

Energy Charge (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
All kWh	$0.000462	$0.041880	Varies	$0.042342

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
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In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BILLING DEMAND

The monthly billing demand shall be the higher of:

1. the highest measured fifteen-minute integrated reading of the demand meter during all hours of the billing period;
2. the highest demand metered during the preceding eleven (11) months; or
3. the contract capacity or 500 kW, whichever is higher.

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

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To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES

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OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$ 184.69 per month
Meter Reading	$ 364.17 per month
Billing & Collection	$ 498.49 per month
Customer Delivery	$ 152.65 per month
Total	$ 1,200.00 per month

Demand Charge <69kW (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 17.50
Generation	$ 2.07
Transmission	$ 2.43

Demand Charge ≥69kW (Unbundled):

Component	Rate
Delivery Services- All kW	
Local Delivery	$ 12.73
Generation Capacity	$ 2.07
Transmission	$ 2.20

Energy Charge Components (per kWh) (Unbundled):

	Rate
Local Delivery	$0.000343
Generation	$0.000100
Transmission	$0.000019

Power Supply Charges (per kWh):

Component	Rate
Base Power Supply	$0.041880
PPFAC (see Rider-1 for current rate)	Varies

ATTACHMENT C

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

ATTACHMENT D

FY 2015 BUDGET REVIEW

Arizona Counties

Cochise County, AZ

ARIZONA TAX RESEARCH ASSOCIATION

Jennifer Stielow
Vice President

Table of Contents

INTRODUCTION TO ARIZONA COUNTY BUDGETS

In an effort to emphasize the importance of the transparent use of taxpayer dollars, as well as compliance with budget and tax laws, ATRA staff annually reviews and meets with county officials of each county to discuss their budgets. The following report includes information compiled by ATRA staff during the FY 2015 budget year for Arizona's 15 counties.

This report includes a detailed analysis of the budgeted revenues and expenditures in the general fund and total funds of each county. The analysis reflects the change in primary and secondary net assessed values, primary rates and levies, as well as the change in the secondary tax rates and levies for overrides, debt service, and the levies of special districts and their associated expenditures.

Budgeted revenue projections are broken down by general fund and special revenue funds. A detailed summary of each county's budgeted expenditures is also provided, which includes the budgeted amounts for employee-related expenses, capital expenditures, debt service requirements, and specific information regarding plans to incur future debt, if applicable.

The summaries included in this document were provided to all counties for review and feedback prior to distribution of this publication. ATRA appreciates the cooperation of the counties and welcomes any additional feedback after the publication of this report.

Arizona County Budgets Rebound

County General Fund (GF) budgets rebounded in FY 2015 with an average increase of 4.3% (See Table 1). Despite the counties increased reliance on their cash balances over the past several years as a result of the recession, the cash position of the counties remains good. The healthy cash balances held by the counties coupled with the recent uptick in state-shared and local tax revenues allowed nearly all the counties to provide employee pay raises this year.

General Fund Budgets

County GF budgets are mainly funded with primary property taxes, state-shared and local sales tax revenues, and Auto in Lieu tax revenue. GF budgets provide a multitude of general government services, including public health, law enforcement, and other general government services. The GF budgets of all but three counties increased this year. The counties with the largest increases occurred in Greenlee (8.9%), Maricopa (7.8%), Navajo (6.4%), and Mohave (6.1%).

Table 1. General Fund Budgets

County	FY 2014	FY 2015	$ Change	% Change
Apache	$18,343,856	$18,404,897	$61,041	0.3%
Cochise	$80,459,345	$81,595,849	$1,136,504	1.4%
Coconino	$70,808,913	$72,591,508	$1,782,595	2.5%
Gila	$46,031,855	$44,230,262	($1,801,593)	-3.9%
Graham	$20,935,438	$21,270,214	$334,776	1.6%
Greenlee	$10,619,841	$11,562,861	$943,020	8.9%
La Paz	$16,318,525	$16,838,277	$519,752	3.2%
Maricopa	$942,780,433	$1,015,901,116	$73,120,683	7.8%
Mohave	$76,154,008	$80,781,059	$4,627,051	6.1%
Navajo	$39,984,750	$42,544,494	$2,559,744	6.4%
Pima	$503,524,831	$521,401,927	$17,877,096	3.6%
Pinal	$193,676,201	$184,084,963	($9,591,238)	-5.0%
Santa Cruz	$27,504,449	$28,661,791	$1,157,342	4.2%
Yavapai	$89,679,704	$94,937,304	$5,257,600	5.9%
Yuma	$77,258,446	$75,292,428	($1,966,018)	-2.5%
TOTALS	**$2,214,080,595**	**$2,310,098,950**	**$96,018,355**	**4.3%**

Counties rely heavily on state shared TPT (sales tax) revenues to support their GF budgets, which represent nearly 70% of the four major revenue sources listed in the table below (Table 2). State shared VLT (Auto in Lieu) account for nearly 19%, followed by local TPT (8%) and PILT revenues (4%).

Table 2. GF Revenues

County	State shared TPT	Local TPT	State Shared VLT* (Auto in Lieu)	PILT	TOTALS
Apache	$4,800,000	$1,200,000	$550,000	$1,109,854	$7,659,854
Cochise	$12,000,000	$7,000,000	$3,500,000	$1,816,386	$24,316,386
Coconino	$19,698,434	$12,697,600	$3,274,036	$1,666,210	$37,336,280
Gila	$4,956,150	$2,600,000	$1,556,944	$3,200,905	$12,313,999
Graham	$4,000,000	$2,000,000	$884,717	$2,778,581	$9,663,298
Greenlee	$4,350,000	$1,200,000	$325,000	$544,675	$6,419,675
La Paz	$2,252,000	$1,412,573	$572,581	$1,928,209	$6,165,363
Maricopa	$465,300,725	N/A	$132,858,100	$12,340,468	$610,499,293
Mohave	$20,519,000	$6,438,200	$6,208,900	$3,412,630	$36,578,730
Navajo**	$11,046,000	$6,816,000	$2,067,000	$1,519,256	$21,448,256
Pima	$106,640,000	N/A	$24,100,000	$2,035,000	$132,775,000
Pinal	$30,273,750	$14,352,000	$9,012,500	$1,215,622	$54,853,872
Santa Cruz	$4,500,000	$2,600,000	$1,400,000	$900,000	$9,400,000
Yavapai	$26,550,000	$15,150,875	$7,275,153	$2,428,943	$51,404,971
Yuma	$19,163,380	$11,794,780	$4,605,707	$3,244,942	$38,808,809
TOTAL	**$736,049,439**	**$85,262,028**	**$198,190,638**	**$40,141,681**	**$1,059,643,786**

*VLT revenues reported under Special Revenue Funds are not included in this table.

**Navajo County did not budget for PILT revenues in FY 2015. The amount reflected in the table is an estimate based on FY 2014 actual revenues.

The total budgets for counties dropped this year by 1.5% (Table 3), which is a smaller reduction relative to last year's 4.1% decrease. In addition to the GF, total funds (TF) include special revenue funds, capital project funds, debt service funds for voter-approved and non-voter approved bonds, and enterprise funds. Included in the special revenue funds are the countywide special taxing districts in which the county boards of supervisors (BOS) sit as the board of directors. The creation of special taxing districts have provided counties with a dedicated funding source separate from the GF to fund a variety of services, such as library services, flood control, public health services, as well as a television district specific only to Mohave County.

Table 3. Total Budgets

County	FY 2014	FY 2015	$ Change	% Change
Apache	$51,171,362	$52,839,970	$1,668,608	3.3%
Cochise	$160,363,511	$151,975,063	($8,388,448)	-5.2%
Coconino	$263,715,576	$235,165,312	($28,550,264)	-10.8%
Gila	$95,252,025	$94,444,905	($807,120)	-0.8%
Graham	$32,891,242	$33,523,198	$631,956	1.9%
Greenlee	$23,572,100	$25,130,309	$1,558,209	6.6%
La Paz	$33,036,650	$32,040,614	($996,036)	-3.0%
Maricopa	$3,065,393,528	$3,060,728,490	($4,665,038)	-0.2%
Mohave	$253,015,076	$252,282,568	($732,508)	-0.3%
Navajo	$118,533,913	$120,792,901	$2,258,988	1.9%
Pima	$1,569,147,951	$1,497,657,953	($71,489,998)	-4.6%
Pinal	$373,723,558	$378,079,096	$4,355,538	1.2%
Santa Cruz	$70,355,234	$74,308,956	$3,953,722	5.6%
Yavapai	$224,231,808	$231,642,537	$7,410,729	3.3%
Yuma	$249,718,511	$242,313,069	($7,405,442)	-3.0%
TOTALS	**$6,584,122,045**	**$6,482,924,941**	**($101,197,104)**	**-1.5%**

Note: Total budgeted amounts represent total financial resources for comparison purposes.

GF Cash Balances

The GF cash on hand reported by Arizona Counties in FY 2015 was $314 million (see Table 4). Total GF cash balances represent an average of 13.6% of total GF budgets, which range from a low of 6.2% in Pima County to a high of 37.6% in Coconino County. Total cash is down $135 million (30%) from last year, mostly as a result of the $116 million reduction in Maricopa County, otherwise the overall reduction would represent just $19 million. Nevertheless, the hefty cash balances that grew during the boom years provided a substantial cushion for the counties to weather the lean years.

The underreporting of cash balances by several counties continues to be a problem. Although state law clearly requires all cash, both restricted and unrestricted, be reported in the county GF balance, Arizona counties underreported their cash by $77 million (15%) based on the most recent financial audits. Although the beginning fund balance is an estimate, the amount budgeted compared to the audited amounts should be fairly close. That is clearly not the case for several counties that failed to report more than 50% of their actual cash balances, such as Apache (underreported by $4.7 million/54%), Greenlee ($5.5 million/59%), La Paz ($2.7 million/100%), and Mohave ($11.2 million/86%). With the exception of La Paz County, the underreporting of cash is the result of a legal interpretation by these counties that they are not required to show cash that they don't plan to spend. The Arizona Auditor General's office has supported ATRA's position that the law requires all cash to be included in the beginning fund balance.

Table 4. General Fund Cash Balances

County	FY 14 GF Budgeted Beg. Cash Balance	Audited (June 30, 2013) Cash Balance*	Diff. between Budgeted & Actual	FY 15 GF Budgeted Beg. Cash Balance	$ Change	% Change	% of FY 2015 GF budget
Apache	$4,000,000	$8,663,279	($4,663,279)	$5,000,000	$1,000,000	25.0%	27.2%
Cochise	$27,892,296	$30,510,247	($2,617,951)	$29,059,354	$1,167,058	4.2%	35.6%
Coconino	$30,237,664	$29,184,907	$1,052,757	$27,259,345	($2,978,319)	-9.8%	37.6%
Gila	$19,848,897	$25,204,358	($5,355,461)	$15,766,569	($4,082,328)	-20.6%	35.6%
Graham	$1,268,293	$2,155,713	($887,420)	$1,926,170	$657,877	51.9%	9.1%
Greenlee*	$3,802,990	$9,344,218	($5,541,228)	$3,532,504	($270,486)	-7.1%	30.6%
La Paz	$0	$2,729,106	($2,729,106)	$1,868,393	$1,868,393	100.0%	11.1%
Maricopa	$230,066,825	$258,686,425	($28,619,600)	$113,712,308	($116,354,517)	-50.6%	11.2%
Mohave*	$1,860,717	$13,026,776	($11,166,059)	$7,695,004	$5,834,287	313.6%	9.5%
Navajo	$4,000,000	$5,870,369	($1,870,369)	$4,300,000	$300,000	7.5%	10.1%
Pima	$44,056,613	$56,684,000	($12,627,387)	$32,474,480	($11,582,133)	-26.3%	6.2%
Pinal	$49,127,286	$47,326,000	$1,801,286	$40,392,961	($8,734,325)	-17.8%	21.9%
Santa Cruz	$10,949,691	$13,458,400	($2,508,709)	$10,336,084	($613,607)	-5.6%	36.1%
Yavapai	$5,268,001	$5,948,186	($680,185)	$6,523,933	$1,255,932	23.8%	6.9%
Yuma	$16,576,861	$17,337,497	($760,636)	$13,777,216	($2,799,645)	-16.9%	18.3%
TOTALS	**$448,956,134**	**$526,129,481**	**($77,173,347)**	**$313,624,321**	**($135,331,813)**	**-30.1%**	**13.6%**

*Apache and Gila County data is based on FY 2012 data, which is their most recent financial audit

Property Values & Levies

Statewide primary net assessed values (NAV) increased 2.7%; however, the growth was isolated to only a few counties. Greenlee County had the largest percentage growth of nearly 37%, followed by Graham County with 10%, Maricopa with 4.8%, and Pinal County with 0.8% growth. Secondary NAV grew at twice the rate of PNAV, with a 5.2% increase in FY 2015.

Table 5. Net Assessed Values

County	FY 2014 PNAV	FY 2015 PNAV	$ Change	% Change	FY 2014 SNAV	FY 2015 SNAV	$ change	% change
Apache	$ 525,723,278	$ 513,655,622	($12,067,656)	-2.3%	$ 531,638,110	$ 517,650,768	$ (13,987,342)	-2.6%
Cochise	1,006,475,403	955,783,522	($50,691,881)	-5.0%	1,011,138,917	959,542,199	$ (51,596,718)	-5.1%
Coconino	1,519,086,333	1,512,794,264	($6,292,069)	-0.4%	1,533,065,282	1,534,483,938	$ 1,418,656	0.1%
Gila	438,624,843	416,099,715	($22,525,128)	-5.1%	440,187,536	419,257,531	$ (20,930,005)	-4.8%
Graham	192,240,653	211,469,611	$19,228,958	10.0%	194,024,943	213,508,436	$ 19,483,493	10.0%
Greenlee	335,715,128	458,425,787	$122,710,659	36.6%	336,148,250	462,439,380	$ 126,291,130	37.6%
La Paz	216,835,366	205,814,389	($11,020,977)	-5.1%	224,552,041	210,720,562	$ (13,831,479)	-6.2%
Maricopa	31,996,204,979	33,519,795,354	$1,523,590,375	4.8%	32,229,006,810	35,079,646,593	$ 2,850,639,783	8.8%
Mohave	1,771,371,872	1,727,793,369	($43,578,503)	-2.5%	1,809,668,423	1,757,074,571	$ (52,593,852)	-2.9%
Navajo	903,351,854	845,018,236	($58,333,618)	-6.5%	904,776,433	846,247,083	$ (58,529,350)	-6.5%
Pima	7,559,129,097	7,518,481,988	($40,647,109)	-0.5%	7,623,691,280	7,579,898,868	$ (43,792,412)	-0.6%
Pinal	1,988,882,373	2,005,151,766	$16,269,393	0.8%	2,005,343,534	2,040,749,841	$ 35,406,307	1.8%
Santa Cru:	338,356,662	320,999,663	($17,356,999)	-5.1%	339,878,006	323,843,644	$ (16,034,362)	-4.7%
Yavapai	2,232,629,599	2,217,272,811	($15,356,788)	-0.7%	2,279,676,521	2,267,389,484	$ (12,287,037)	-0.5%
Yuma	1,112,115,440	1,112,447,688	$332,248	0.0%	1,131,581,406	1,139,598,176	$ 8,016,770	0.7%
Total	**$ 52,136,742,880**	**$ 53,541,003,785**	**$1,404,260,905**	**2.7%**	**$ 52,594,377,492**	**$ 55,352,051,074**	**$ 2,757,673,582**	**5.2%**

The average primary tax rates adopted by Arizona's counties increased over 7 cents, from $2.1046 to $2.1788 (See Table 6). Four counties left their tax rates the same while two reduced their rates. Overall, eight counties adopted tax rates within their truth in taxation (TNT) limits. Under the TNT laws, local governments are required to notify taxpayers of their intent to increase primary property taxes (exclusive of new construction) over the previous year. This year, seven counties exceeded their TNT limits, with the most significant increase in Pima County. Despite the extensive opposition from Pima County taxpayers and businesses, the Pima County BOS adopted a staggering 61-cent primary property tax rate increase. As a result, Pima County has regained the unfavorable distinction of levying the highest tax rate of all the counties with the adoption of its $4.2779 tax rate, which exceeds the average county primary tax rate by $2.0991.

Table 6. Primary Tax Rates

County	FY 2014	FY 2015	$ Change	% Change	Max Tax Rate	TNT	$ over TNT
Apache	$0.4593	$0.4810	$0.0217	4.7%	$0.4810	$0.4716	$0.0094
Cochise	$2.6276	$2.6276	$0.0000	0.0%	$3.3418	$2.8295	-$0.2019
Coconino	$0.5466	$0.5646	$0.0180	3.3%	$0.5646	$0.5535	$0.0111
Gila	$4.1900	$4.1900	$0.0000	0.0%	$6.7275	$4.5318	-$0.3418
Graham	$2.3711	$2.1794	($0.1917)	-8.1%	$2.3127	$2.1794	$0.0000
Greenlee	$0.7350	$0.5500	($0.1850)	-25.2%	$0.5559	$0.5390	$0.0110
La Paz	$1.9608	$2.2863	$0.3255	16.6%	$2.2863	$2.1145	$0.1718
Maricopa	$1.2807	$1.3209	$0.0402	3.1%	$1.8068	$1.2486	$0.0723
Mohave	$1.8196	$1.8196	$0.0000	0.0%	$2.2729	$1.8909	-$0.0713
Navajo	$0.6995	$0.8185	$0.1190	17.0%	$0.8185	$0.7561	$0.0624
Pima	$3.6665	$4.2779	$0.6114	16.7%	$4.9720	$3.7633	$0.5146
Pinal	$3.7999	$3.7999	$0.0000	0.0%	$5.9982	$3.8371	-$0.0372
Santa Cruz	$3.4215	$3.6471	$0.2256	6.6%	$4.1822	$3.6471	$0.0000
Yavapai	$1.9308	$1.9580	$0.0272	1.4%	$2.2599	$1.9732	-$0.0152
Yuma	$2.0606	$2.1608	$0.1002	4.9%	$2.4470	$2.1609	-$0.0001
Avg. Rates	**$2.1046**	**$2.1788**	**$0.0741**	**3.5%**	**$2.7352**	**$2.1664**	**$0.0123**

Overall, primary levies adopted by the counties increased more than $78 million (8.3%). Six counties that are at or near (within 10%) their constitutional levy limit include Apache, Coconino, Graham, Greenlee, La Paz, and Navajo County (Table 7).

Table 7. Primary Levies

County	FY 2014	FY 2015	$ Change	% Change	Max Levy
Apache	$2,414,647	$2,470,684	$56,037	2.3%	$2,470,684
Cochise	$26,446,148	$25,114,167	($1,331,981)	-5.0%	$31,940,374
Coconino	$8,303,326	$8,541,236	$237,910	2.9%	$8,541,236
Gila	$18,378,381	$17,434,578	($943,803)	-5.1%	$27,993,108
Graham	$4,558,218	$4,608,769	$50,551	1.1%	$4,890,658
Greenlee	$2,478,151	$2,521,341	$43,190	1.7%	$2,548,389
La Paz	$4,251,708	$4,705,534	$453,826	10.7%	$4,705,534
Maricopa	$409,775,397	$442,762,977	$32,987,580	8.1%	$605,635,662
Mohave	$32,231,883	$31,438,928	($792,955)	-2.5%	$39,271,015
Navajo	$6,318,553	$6,916,474	$597,921	9.5%	$6,916,474
Pima	$277,155,468	$321,633,141	$44,477,673	16.0%	$373,818,925
Pinal	$75,575,541	$76,193,762	$618,221	0.8%	$120,273,013
Santa Cruz	$11,576,873	$11,707,247	$130,374	1.1%	$13,424,848
Yavapai*	$43,108,560	$43,415,263	$306,703	0.7%	$50,108,148
Yuma	$22,916,250	$24,037,770	$1,121,520	4.9%	$27,221,595
TOTALS	**$945,489,104**	**$1,023,501,871**	**$78,012,767**	**8.3%**	**$1,319,759,663**

*The primary property tax levy for Yavapai County includes an additional levy of $306,703 for the Transwestern judgment.

Charges to Special Districts

Most of the 15 counties charge their special revenue funds, particularly their countywide special taxing districts, for the reimbursement of county services. The methodology used to determine the amount to charge the Districts vary between counties but should be representative of real costs associated with those Districts.

In addition, the state budget has included a provision over the last several years that has allowed the counties with population under 200,000 to transfer revenues from any special revenue source including countywide special taxing districts to their general funds to meet any financial obligation. Effective for FY 2014, the counties were required for the first time to report those transfers to the Joint Legislative Budget Committee. Of the ten counties that qualify for the transfers, only three reported using the flexibility language to transfer a total of $1.3 million from their special revenue funds to their GF. Apache County transferred $500,000 from three of its special taxing districts, Navajo $580,300 from the Public Health Services District, and Yuma transferred $28,868 from a few of its special taxing districts to their GF. The remaining qualifying counties that did not use the flexibility language included Cochise, Coconino, Gila, Graham, Greenlee, La Paz, and Santa Cruz Counties[1].

County Employee Compensation

In recent years, most counties opted to award employees with one-time distributions due to the uncertain economic times. However, now that county GF revenues are on the rise again, almost all of the counties made the decision to award employee pay raises. Many of the counties that previously awarded only one-time distributions moved to permanent pay raises this year, which included raises for cost-of-living (COLA), pay-for-performance (PFP), and market adjustments. Many counties have either conducted or are in the process of conducting a classification and compensation study conducted to make a determination on current and future employee pay increases (Table 8).

Table 8. Employee Compensation

County	FY 2014 Budget	Estimated Total Impact	FY 2015 Budget	Estimated Total Impact
Apache	5% COLA	$420,000	2%/3% COLA	$200,000
Cochise	one-time distribution	$1,482,000	One-time distribution + Market adjustments	$1.08 million
Coconino	1.5% market + 2.5% merit on anniversary	$2.75 million	2.5% Merit + $400k for compression adj.	$1.7 M (TF)
Gila	classification & compensation study	$2 million slated	Avg. 6.2% increase	$1.34 M (GF)
Graham	longevity raises	$53,000	longevity + 4% avg. market adj.	$346k (GF), $561k (TF)
Greenlee	3.5% increase + 1.5% add'l for sheriffs	$550,000	3% across the board	$160K (GF), $251K (TF)
La Paz	N/A	N/A	3% COLA	$250k (GF), $500k (TF)
Maricopa	PFP 5% avg. + equity adjs.	$67 million	2.5% PFP, Market adj., Ed Asst Program	$16.6 M (GF), $27.5 M (TF)
Mohave	2.5% COLA	$1.7 million	Conditional reclassifications	$180,100 (TF)
Navajo	2% adj.	$300,000	2% COLA, cond.2% one-time payment, Sheriff's mkt adj.	$784k (GF), $1.2 M (TF)
Pima	1% COLA + 2% + one-time adj	$12 million	$0.50 increase to all employees	$5.3 M (GF), $7.8M (TF)
Pinal	2.5% Merit	$2.4 million (annualized)	2.5% (conditional distribution in 4th QTR)	$2.2M (GF), $2.8 M (TF)
Santa Cruz	one-time distribution	$204,750	5% across the board	$359k (GF), $785k (TF)
Yavapai	Not budgeted	N/A	1% COLA, 0-3% adj.	$1.3 M (GF), $2.6 M (TF)
Yuma	Step increases	$1.69 million	Reclassifications	$27,114 (GF), $55,570 (TF)

*See county summaries for details on budgeted employee compensation.

Total GF salaries, including employee related expenses (EREs), increased 5.5% to approximately $1.3 billion in FY 2015. This year's increase was mainly driven by the 6.5% growth in EREs, which accounts for 30% of total employee compensation. EREs include the costs associated with retirement, health care, FICA, and Medicare. Employee salaries, which represent the majority of total compensation, grew 5.5%. The counties with the largest percentage increases in salaries were Greenlee (9.4%), Maricopa (8.5%), Navajo (7.4%), Coconino (5.1%), and Apache (5%). Employee compensation as a percentage of county GF budgets averaged approximately 55% in FY 2015, ranging from a low of 41% in Santa Cruz County to a high of nearly 63% in Yavapai County.

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[1] JLBC Monthly Fiscal Highlights, November 2013.

Table 9. General Fund

County	FTE'S		Salaries		Employee Related Exp.		Total Comp			
	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015	% Chg.	% of GF
Apache	154	165	$6,531,918	$6,858,429	$3,354,376	$3,175,628	$9,886,294	$10,034,057	1.5%	54.5%
Cochise	614	617	$28,146,530	$28,465,516	$11,174,045	$11,221,023	$39,320,575	$39,686,539	0.9%	48.6%
Coconino	487	497	$25,447,329	$26,738,366	$10,479,121	$10,999,580	$35,926,450	$37,737,946	5.0%	52.0%
Gila	413	404	$16,771,930	$16,335,391	$7,102,563	$7,014,193	$23,874,493	$23,349,584	-2.2%	52.8%
Graham	190	187	$8,494,295	$8,485,783	$2,726,287	$2,735,533	$11,220,582	$11,221,316	0.0%	52.8%
Greenlee	92	101	$4,286,247	$4,687,149	$1,820,229	$2,074,735	$6,106,476	$6,761,884	10.7%	58.5%
La Paz	131	130	$6,159,930	6,159,930	$2,660,706	2,667,535	$8,820,636	8,827,465	0.1%	52.4%
Maricopa*	7,339	7,620	$392,811,367	$426,022,150	$143,907,311	$159,184,541	$477,099,455	$519,517,084	8.9%	51.1%
Mohave	711	717	$32,140,407	$32,308,397	$14,051,947	$14,119,349	$46,192,354	$46,427,746	0.5%	57.5%
Navajo	376	394	$16,507,161	$17,722,468	$7,019,621	$7,733,837	$23,526,782	$25,456,305	8.2%	59.8%
Pima	4,739	4,755	$207,371,588	$217,362,979	$88,473,823	$92,192,216	$295,845,411	$309,555,195	4.6%	59.4%
Pinal	1,544	1,572	$81,358,979	$82,685,522	$29,671,584	$30,515,661	$111,030,563	$113,201,183	2.0%	61.5%
Santa Cruz	180	183	$8,161,289	$8,216,867	$3,534,033	$3,600,181	$11,695,322	$11,817,048	1.0%	41.2%
Yavapai	850	874	$40,565,156	$42,350,296	$16,097,460	$17,120,936	$56,662,616	$59,471,232	5.0%	62.6%
Yuma	666	659	$31,177,515	$30,910,513	$12,761,417	$13,665,260	$43,938,932	$44,575,773	1.4%	59.2%
TOTALS	**18,486**	**18,875**	**$905,931,641**	**$955,309,756**	**$354,834,523**	**$378,020,208**	**$1,201,146,941**	**$1,267,640,357**	**5.5%**	**54.9%**

*Total compensation in the Maricopa County FY 2014 GF budget nets out $59,619,223 in Personnel Allocation costs and $65,689,607 in FY 2015.

In FY 2015, full-time equivalents (FTEs) included in the county GF budgets represent 57% of total budgeted FTEs and varies between the fifteen counties (Table 9). The difference between counties can be due to the level of reliance on special taxing districts. For example, a low percentage of FTEs in the GF may be reflective of a county that has greater reliance on special taxing districts compared to a county that funds the same services from its GF without creating an additional taxing source. The percentage of GF budgeted FTEs as a percentage of total FTEs ranges from a low of 41% in Apache County, which relies the most on special taxing districts, to a high of 74% in Pinal County, which relies less on special taxing districts.

Total employee compensation, including EREs, in all funds increased 5.7% to over $2.2 billion in FY 2015 as a result of a 5.2% increase in EREs and a 5.9% increase in salaries. Total budgeted FTEs in FY 2015 are up 1.2% and amounted to 33,261 (Table 10).

Table 10. Total Funds

County	FTE'S		Salaries		Employee Related Exp.		Total Comp			
	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015	FY 2014	FY 2015	% Chg.	% of TF
Apache	390	404	$14,413,425	$14,873,372	$7,155,563	$6,728,728	$21,568,988	$21,602,100	0.2%	40.9%
Cochise	908	898	$39,677,358	$40,246,293	$15,555,590	$15,651,738	$55,232,948	$55,898,031	1.2%	36.8%
Coconino	1,056	1,062	$50,638,768	$53,441,204	$21,146,941	$21,566,075	$71,785,709	$75,007,279	4.5%	31.9%
Gila	660	652	$25,882,666	$25,412,964	$10,908,052	$10,890,871	$36,790,718	$36,303,835	-1.3%	38.4%
Graham	264	260	$11,852,238	$11,617,613	$3,607,957	$3,767,184	$15,460,195	$15,384,796	-0.5%	45.9%
Greenlee	160	168	$6,525,373	$6,939,938	$2,855,093	$3,120,812	$9,380,466	$10,060,750	7.3%	40.0%
La Paz	278	289	$11,371,360	11,953,745	$5,130,317	5,344,543	$16,501,677	17,298,288	4.8%	54.0%
Maricopa	14,423	14,812	$711,507,690	$774,095,998	$268,841,994	$290,877,185	$980,349,684	$1,064,973,183	8.6%	34.8%
Mohave	1,272	1,275	$55,863,245	$55,347,435	$24,245,262	$24,163,337	$80,108,507	$79,510,772	-0.7%	31.5%
Navajo	679	692	$28,256,868	$29,320,344	$11,339,115	$12,639,255	$39,595,983	$41,959,599	6.0%	34.7%
Pima	7,328	7,255	$311,458,136	$330,630,578	$132,676,288	$134,022,351	$444,134,424	$464,652,929	4.6%	31.0%
Pinal	2,123	2,118	$108,398,857	$109,994,918	$38,321,770	$39,821,972	$146,720,627	$149,816,890	2.1%	39.6%
Santa Cruz	386	378	$16,553,523	$16,366,043	$7,033,273	$6,987,181	$23,586,796	$23,353,224	-1.0%	31.4%
Yavapai	1,504	1,555	$69,275,429	$72,779,035	$26,928,645	$28,844,580	$96,204,074	$101,623,615	5.6%	43.9%
Yuma	1,445	1,443	$64,910,376	$63,769,342	$26,429,124	$28,113,302	$91,339,500	$91,882,644	0.6%	37.9%
TOTALS	**32,876**	**33,261**	**$1,526,585,312**	**$1,616,788,822**	**$601,492,196**	**$632,539,114**	**$2,128,077,508**	**$2,249,327,936**	**5.7%**	**34.7%**

APACHE COUNTY

Overview

- Apache's GF budget for FY 2015 is $18,404,897. This represents an increase of $61,041 over last year's budget of $18,343,856.
- The County's GF balance is $5 million (27% of the GF budget). This amount is underreported by $3 million. The FY 2015 county budget presentation to the BOS shows the actual opening fund balance is nearly $8 million (43% of the GF budget), which County officials confirm is accurate.
- The total budget for FY 2015 is $52,839,970, which represents an increase of $1,668,608 (3.3%) over last year's budget of $51,171,362.

Property Values

- The primary NAV decreased 2.3% to $513,655,622. New construction amounted to $1,605,610 (0.31% of total NAV). The secondary NAV is down 2.6% to $517,650,768.

Property Tax Revenues

Primary Levy

- Apache County adopted its maximum tax rate of $0.4810. Since the adopted rate exceeded the TNT rate of $0.4716, the County was required to publish notice and hold a public hearing regarding the tax increase.
- The primary levy increased $56,037 (2.3%), from $2,414,647 to $2,470,684.

Flood Control District

- The District's NAV decreased $12,263,464 (5.5%), from $223,646,043 to $211,382,579.
- In FY 2014, there was enough in reserves to operate the District that the BOS did not need to levy a tax. In FY 2015 however, the County levied a tax rate of $0.0442, which resulted in a levy of $98,852.
- The FY 2015 District budget is down $182,708 (48%), from $382,000 to $199,292.
- The FY 2015 beginning fund balance in the District is approximately $200,000.

Library District

Operations

- The secondary tax rate for operations in the Library District is up $0.0714, from $0.2160 to $0.2874. As a result, the levy increased $339,390 (29.6%), from $1,148,338 to $1,487,728.
- The District's operating budget of $1,617,563 is $5,437 below last year's budget. The balance in the fund was approximately $785,000 in FY 2014, which dropped to nearly $150,000 in FY 2015.

GO Bonds

- At the November 2006 General Election, voters approved $7.19 million in General Obligation (GO) bonds to construct new libraries.
- The tax rate levied for bonds increased from $0.0813 to $0.0989. As a result, the levy increased $79,735 (18.4%), from $432,222 to $511,957.
- The FY 2015 debt service payment for the bonds is $915,000; however, the actual required payment is only $715,000. The fund balance in the District's GO debt fund was $500,000 in FY 2014. The FY 2015 beginning fund balance is $157,000.

Jail District

- The tax rate levied for the Jail District of $0.2000 is the maximum rate per statute. The FY 2015 levy is $1,035,302, a decrease of $27,974 (2.6%) below the FY 2014 levy.
- Apache County budgeted $686,350 in Federal inmate housing in FY 2015, $63,350 (8.5%) less than last year's budget (FY 2014 actual revenues were only $85,995). The County lost most of its Federal inmates and now currently has contracts with the Apache Reservation, Graham County, and is working on a contract

with the Navajo Nation. The adult facility can hold up to 178 beds. The jail was nearly 80% occupied on average in FY 2014 and is average occupancy is currently down to approximately 40%.

- The amount of budgeted FTEs in the District did not change as a result of the loss in Federal inmates. There are currently 39 FTEs in the District.
- The Jail District's budget decreased $812,115 (22.6%), from $3,591,333 to $2,779,218 (FY 2014 actual estimated expenditures amounted to $2,416,888).
- The maintenance of effort (MOE)[2] payment is $450,516 in FY 2015.
- In FY 2014, the budgeted medical expenses in the jail were flat at approximately $110,000 and dropped slightly to $105,000 in FY 2015. The District uses a contractor in Maricopa County to facilitate psychological medical care to inmates.
- The District's beginning fund balance in FY 2014 was $362,000 and dropped to approximately $200,000 in FY 2015.

Juvenile Jail District

- The Juvenile Jail District tax rate decreased from $0.0930 to $0.0916. The levy decreased $20,255 (4.1%), from $494,423 to $474,168.
- The juvenile facility holds 13 beds and the average occupancy is approximately 30%. The County does not rent beds to other entities but that option is currently being considered.
- The District budget decreased $50,695 (6%), from $844,343 to $793,648.
- The MOE payment is $316,033 in FY 2015.

Community College/Post Secondary Education

- Community College: Since there is no community college district in Apache County, the County levies a property tax to pay the cost of tuition for residents that attend other colleges. The tax rate levied for junior college tuition is down $0.0165, from $0.2982 to $0.2817. As a result, the levy decreased $127,123 (8%), from $1,585,345 to $1,458,222.
- The State General Fund budget partially offsets the costs incurred by Apache County. In FY 2015, tuition assistance from the state increased $233,300 (50%), from $466,000 to $699,300.
- The budget stayed the same at $2,600,650.
- Post Secondary Education: The tax rate levied for post secondary education to operate a local branch of Northland Pioneer College is staying the same at $0.1000. As a result, the levy decreased $13,987 (3%), from $531,638 to $517,651. The budget remains the same at $630,000.

Public Health Services District

- The District was created by a unanimous vote of the Board in April 2007 and FY 2008 was the first year the County levied a property tax for the District.
- The tax rate levied in FY 2015 decreased slightly from $0.1274 to $0.1260. This year's tax rate generated a levy of $652,240, $25,067 (3.7%) less than last year.
- The budget increased $107,436 (24%), from $447,058 to $554,494 (operations budget only).
- The MOE payment from the GF to the District is $105,688.
- The District's fund balance in FY 2014 was $398,000. The FY 2015 beginning fund balance is approximately $424,000.

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[2] A County that creates a Jail District and/or a Juvenile Jail District is required to maintain the same level of support of corrections facilities and programs by making a Maintenance of Effort (MOE) payment each year from the county GF to the District. The Auditor General determines the payment by using the amount expended by the County in the preceding fiscal year in which the District was initially created and adjusting that amount by the lesser of the annual change in the county primary property tax levy limit or the change in the GDP price deflator.

APACHE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.4593	0.4810	0.0217	0.4716	$2,414,647	$2,470,684	$56,037	2%
Flood Control	0.0000	0.0442	0.0442		$0	$98,852	$98,852	100%
Library*	0.2973	0.3863	0.0890		$1,580,560	$1,999,685	$419,125	27%
Jail District	0.2000	0.2000	0.0000		$1,063,276	$1,035,302	-$27,974	-3%
Juvenile Jail	0.0930	0.0916	-0.0014		$494,423	$474,168	-$20,255	-4%
JR College	0.2982	0.2817	-0.0165		$1,585,345	$1,458,222	-$127,123	-8%
Post S.Ed	0.1000	0.1000	0.0000		$531,638	$517,651	-$13,987	-3%
Public Health Services	0.1274	0.1260	-0.0014		$677,307	$652,240	-$25,067	-4%
OVERALL RATE	**1.5752**	**1.7108**	**0.1356**		**$8,347,196**	**$8,706,804**	**$359,608**	**4%**

*Apache's Library District rate and levy is for operations and voter-approved GO bonds.

Other GF Revenues

- VLT is up $30,000 (5.8%), from $520,000 to $550,000.
- State shared sales tax revenues are up $200,000 (4.3%), from $4,600,000 to $4,800,000.
- The budgeted half-cent sales tax remains level at $1,200,000.
- PILT decreased $442,091 (28.5%), from $1,551,945 to $1,109,854.
- In FY 2015, the County received $550,038 in lottery revenue from the state.

Special Revenues

Road Fund

- HURF revenue is up $550,000 (10.6%), from $5,200,000 to $5,750,000.
- VLT revenue is down $100,000 (4.8%) to $2,000,000.
- In FY 2014, the fund balance in the Road Fund was approximately $1.4 million and increased to $2.5 million in FY 2015.
- The budget increased $1,600,251 (19.1%), from $8,381,782 to $9,982,033.

Charges to Special Districts - This section shows the charges for reimbursement of indirect services and/or per parcel charges to its special taxing districts and other special revenue funds.

- The amount transferred from the special taxing districts to the GF in FY 2014 amounted to $2,256,829 and $2,257,459 in FY 2015 (includes additional transfers of $500,000 in each fiscal year as authorized by the state budget provision to offset state cost shifts):
  - Flood Control District – FY 2014 = $112,361; FY 2015=$127,418
  - Library District – FY 2014 = $251,293; FY 2015 = $390,492
  - Jail District – FY 2014 = $400,000; FY 2015 = 0
  - Juvenile Jail District – FY 2014 = $213,496; FY 2015 = $218,477
  - Public Health Services District – FY 2014 = $351,997; FY 2015 = $566,229
  - Road Fund – FY 2014 = $927,682; FY 2015 = $954,843

Expenditures

- Employee compensation: In FY 2014, the County awarded employee's with a 5% COLA, effective the first pay period in July. The estimated total cost was $420,000 [$280,000 to the GF/$140,000 to other funds (OF)]. The FY 2015 budget includes a 3% COLA for employees making less than $50,000 and 2% for all other employees, amounting to a total impact of approximately $200,000.
- Budgeted payroll: In FY 2014, GF budgeted payroll, including EREs, were budgeted at $9,886,294. The payroll in TF was budgeted at $21,289,355. In FY 2015, the GF budgeted payroll increased to $10,034,057 and total budgeted payroll increased to $21,602,101.
- Health benefits: The County covers 98% of the health premium costs for employees and 76% (on average) for dependents. In FY 2014, health insurance costs increased 5% and was passed on to employees at a cost of $120/employee. There was a minimal increase in health insurance costs in FY 2015.
- Budgeted FTEs: In FY 2015, FTEs in the GF increased from 154 to 165. The FTEs in TF increased from 390 to 404.
- Employee vacancy & turnover rates: The employee turnover rate was 19% in 2013. The current employee vacancy rate is unknown.

Capital Projects/Debt

According to the Arizona Department of Revenue's FY 2014 Report of Bonded Indebtedness, the Library District had $4,245,000 in outstanding GO debt. As noted previously under the Library District summary, the FY 2015 debt service payment is $915,000. In addition, the County has a loan from the Greater Arizona Development Authority (GADA), which has an outstanding balance of $3,580,000. Currently, the County is paying interest-only on the GADA loan but is building up reserves in order to pay off the loan in FY 2017.

COCHISE COUNTY

Overview

- Cochise County's GF budget for FY 2015 is $81,595,849, a $1,136,500 (1.4%) increase above the FY 2014 budget of $80,459,345.
- The County has a beginning fund balance of $29,059,354, an increase of $1,167,058 (4.2%) above last year. The beginning fund balance represents 35.6% of the total GF budget.
- The total budget is $151,975,063, which is a decrease of $8,388,448 (5.2%) below last year's adopted budget of $160,363,511.

Property Values

- The primary NAV dropped 5.6% to $955,783,522. New construction amounted to $21,122,320 (2.21% of total NAV). The secondary NAV is down 5.1% to $959,542,199.

Property Tax Revenues

Primary Levy

- The primary tax rate remains the same at $2.6276 in FY 2015. Since the tax rate is lower than the TNT rate of $2.8295, the County was not required to hold a TNT hearing.
- The primary property tax levy dropped $1,331,981 (5%) to $25,114,167.

Flood Control District

- The District's NAV decreased $46,561,018 (5.4%), from $855,854,956 to $809,293,938.
- The secondary tax rate for the District remains the same at $0.2597. The levy decreased from $2,222,655 to $2,101,736, $120,919 (5%) less than last year.
- Budgeted expenditures for the District are $5,924,340, a decrease of $1,290,335 (17.9%). The estimated actual expenditures reported for last year amounted to $3,119,622, 43% of budgeted expenditures.
- In FY 2014, the beginning fund balance was $5,306,375. In FY 2015, the district's beginning fund balance is $4.1 million, which is estimated to drop to $2 million by the end of the fiscal year. Reserves have been built up to fund a variety of projects, which will be steadily drawn down over the next few years.

County Library

- The Library District levy is $1,392,296, $74,867 (5%) less than last year's levy. The rate remains the same at $0.1451.
- The District budget dropped $206,160 (9%), from $2,294,664 to $2,088,504. The County operates five branches and a bookmobile. The District also operates the information system that is used by the city libraries.
- The beginning fund balance in FY 2014 was $883,085 and increased slightly to $894,000 in FY 2015. The reserves in the District will be used to purchase a new library cataloging system in the future at an estiamted cost of $500,000.

COCHISE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	2.6276	2.6276	0.0000	2.8295	$26,446,148	$25,114,167	-$1,331,981	-5%
Flood Control	0.2597	0.2597	0.0000		$2,222,655	$2,101,736	-$120,919	-5%
Library	0.1451	0.1451	0.0000		$1,467,163	$1,392,296	-$74,867	-5%
OVERALL RATE	**3.0324**	**3.0324**	**0.0000**		**$30,135,966**	**$28,608,199**	**-$1,527,767**	**-5%**

Other GF Revenues

- Budgeted Auto in Lieu revenues remain the same at $3,500,000.
- State shared sales tax is up $600,000 (5.3%), from $11,400,000 to $12,000,000.
- The County's half-cent sales tax in FY 2015 is budgeted at $7,000,000.
- PILT is budgeted to remain the same in FY 2015 at $1,816,386.
- The County budget includes $550,000 in State lottery fund revenues.

Special Revenues

HURF

- HURF revenues are up $792,279 (9.8%), from $8,100,000 to $8,892,279 (estimated actual revenues for FY 2014 are reported at $8,542,279).
- The HURF budget increased slightly to $15,134,349.

Charges to Special Districts

- Library District - In FY 2014, the County charged the District a $1.44 per parcel fee for the printing and mailing of tax bills, which amounted to a total charge of $181,872. The per parcel fee for FY 2015 is $181,900. The County also charged the District $256,431 for overhead costs.
- Flood Control District - In FY 2014, the $1.44 per parcel fee amounted to a total charge of $181,872 to the District. In FY 2015, the per parcel fee amounted to $181,900. An additional $64,197 was charged for overhead costs.
- Other taxing districts - In FY 2014, the County charged all of the other special taxing districts a total of $53,388 for indirect costs. The County charged the districts $53,328 in FY 2015.

Expenditures

- Employee compensation: In December 2013, the County provided employees with a one-time distribution that amounted to a total cost of $1.482 million ($1,000,000 impact to the GF). The distributions were based on employee performance and made in two separate payments in Decembers 2013 and May 2014. In addition, during FY 2014, the County provided market adjustments to Detention Officers due to high turnover. The County conducted an in-house study to determine the market adjustments, which was estimated to cost approximately $270,000 on an annual basis.
- For FY 2015, the County will be providing employees with one-time distributions once again at a maximum total cost of $880,000 ($600,000 to the GF and an estimated cost of $280,000 to OF). The distributions will be based on performance and are estimated to go into effect mid-fiscal year. The County also set aside an additional $200,000 in the GF for market adjustments that may be needed throughout the year and to assist in filling high turnover positions.
- Budgeted payroll: In FY 2015, the GF budgeted payroll, including EREs, increased from $39,320,575 to $39,686,539. Total budgeted payroll increased from $55,232,948 to $55,898,031.
- Health benefits: The 2.8% increase in health premium costs in FY 2013 was absorbed by the County. The impact to the GF was $103,826 and the impact to other funds was $57,703. The County subsidizes 100% of the employee's premiums and 44.5% of dependents (tiered system). There was no change in health care costs in FY 2014 and FY 2015.
- Budgeted FTEs: In FY 2015, the GF budgeted FTEs increased by 3 to 617 and TF FTEs dropped 10 to 898.
- Employee turnover & vacancy rates: In FY 2014, the employee vacancy rate was approximately 11% for all funds. The employee turnover rate was 22.4%.
- **Jail Facilities**:
  - **Juvenile**: The County has one juvenile facility with 20 detention cells that are double-bunked for a total of 40 beds. The average occupancy is estimated at 13. The County does not rent beds to other entities.
  - **Adult**: The adult facility is designed to hold 160 beds but actually accommodates 260 beds with double bunking, with an occupancy rate of approximately 77%. The County rents beds annually to the military, Customs, and Federal prisoners at a daily rate of $57.94. Federal prisoner reimbursements were budgeted at $9,000 in FY 2014. The Cochise County Jail operates a clinic in order to provide medical care to inmates and the Cochise County Health Department provides full-time medical professionals to the jail. Inmates are required to make a co-payment for medical services and medication. Medical costs for the jail were budgeted at $981,120 in FY 2014, which included $195,498 for mental health. The estimated medical costs for FY 2015 are budgeted at approximately $1 million.

Capital Projects

In FY 2015, the Capital Projects budget decreased from $29,117,440 to $22,220,813. The following is a list of some of the major capital projects:

- Jail Remodel ($2,500,000)
- Network upgrade ($600,000)
- Microwave improvements ($1,500,000)
- CCSO Regional Evidence Storage Facility ($130,000)
- IT Network backbone/infrastructure upgrade ($200,000)
- BDI Sweeper ($116,200)
- Joint Dispatch ($150,000)
- Mgt System Software ($104,153)
- Davis Road ($165,000)
- Communications Project ($771,601)

As noted in the above list, the County is currently considering a remodel of the existing jail facility at a maximum cost of $2.5 million. Although the jail population has been declining, partly due to a loss of Federal prisoners, the County must separate the prisoners with mental health issues and juveniles being tried as adults as well as the women prisoners, from the general prison population. Although the County has most if not all of the cash on hand to pay for the project, the County is currently near its Constitutional expenditure limit. County officials are considering all options, including the possibility of going to the voters to increase the base expenditure limit.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County held $3,165,000 in outstanding certificates of participation (COPs). The COPs funded the construction of the Melody Lane County Complex; however, County officials claim they have since paid the debt in full. The County also held $210,804 in outstanding lease purchase debt at the end of FY 2014.

COCONINO COUNTY

Overview

- Coconino County's GF budget for FY 2015 is $72,591,508. This is an increase of $1,782,595 (2.5%) over last year's budget of $70,808,913.
- The County's beginning fund balance decreased $2,978,319 (9.8%) in FY 2015 to $27,259,345. The fund balance is equivalent to 37.6% of the GF budget.
- Coconino County's total budget (financial resources) for FY 2015 is $235,165,312, a decrease of $28,550,264 (10.8%) below last year's budget of $263,715,576. The dramatic decrease in the total budget is largely the result of a $28 million reduction in unawarded grants. Of the total financial resources available, the County budgeted to spend $201,010,897.

Property Values

- In FY 2015, Coconino County's primary NAV fell just 0.41% to $1,512,794,264. New construction amounted to $12,653,745 (0.84% of total NAV). The Secondary NAV grew slightly to $1,534,483,938.

Property Tax Revenues

Primary Levy

- The County adopted its maximum tax rate of $0.5646, which exceeded the TNT rate of $0.5535 by $0.0111. As a result, the County was required to hold a TNT hearing and publish notice of the tax increase.
- The primary tax levy increased $237,910 (2.9%), from $8,303,326 to $8,541,236.

County Library

- The County kept the library district tax rate stayed the same at $0.2556. As a result, the levy increased $3,626 to $3,922,141.
- The budget decreased $4,925, from $3,834,594 to $3,829,669.
- In FY 2014, the estimated beginning fund balance was $254,789. The beginning fund balance in FY 2015 is 259,407.

Flood Control District

- The District's NAV dropped $11,299,482 (1.8%), from $617,332,542 to $606,033,060.
- Coconino County's Flood Control District tax is levied on all properties outside the cities of Flagstaff, Page, and Fredonia. The tax rate in FY 2015 remains the same at $0.4000.
- The levy increased $83,392 (3.4%), from $2,469,330 to $2,552,722.
- The District budget is down $710,608 (5.2%), from $13,736,681 to $13,026,073.
- In FY 2014, the beginning fund balance was estimated at $1,858,516. The beginning fund balance for FY 2015 is zero.

Public Health Services District

- The District was created in 2009 by a unanimous vote of the BOS. In FY 2011, the County levied a property tax for the first time and set the tax rate at the 25-cent maximum per state statute.
- In FY 2015, the levy increased $3,547 to $3,836,210.
- Other special revenue budgeted in the District in FY 2015 increased $57,136, from $5,802,075 to $5,859,211.
- In FY 2013, the MOE payment for the District was $3,739,233 and the County transferred an additional $299,155 from the GF to the District to augment the drop in property taxes (intended to be paid back in the future when the property taxes rebound). For FY 2014, the MOE increased to $3,851,420 and an additional $767,694 was transferred from the GF to the District to offset property taxes, as well as an additional $535,000 for Title 36 contracts (mental health services). The FY 2015 MOE increased to $3,928,438.
- The FY 2015 District budget (operating only) is up $89,403 (0.9%), from $10,292,465 to $10,381,868.

- The District's beginning fund balance in FY 2014 was estimated at $251,580 and increased to approximately $1.4 million in FY 2015.

COCONINO COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.5466	0.5646	0.0180	0.5535	$8,303,326	$8,541,236	$237,910	3%
Library	0.2556	0.2556	0.0000		$3,918,515	$3,922,141	$3,626	0%
Flood Control*	0.4000	0.4000	0.0000		$2,469,330	$2,552,722	$83,392	3%
Public Health Services	0.2500	0.2500	0.0000		$3,832,663	$3,836,210	$3,547	0%
OVERALL RATE	**1.4522**	**1.4702**	**0.0180**		**$18,523,834**	**$18,852,309**	**$328,475**	**2%**

*Applies to all property outside the cities of Flagstaff, Page, and Fredonia.

Other Revenues

GF Revenues

- Auto in Lieu revenues decreased $91,074 (2.7%), from $3,365,110 to $3,274,036.
- State shared sales tax is up $21,546, from $19,676,888 to $19,698,434.
- The half-cent sales tax is up $5,821, from $12,691,779 to $12,697,600.
- PILT revenue is up $593,210 (55.3%), from $1,073,000 to $1,666,210.
- Non-departmental revenue decreased $347,647 (10%), from $3,334,001 to $2,986,354. This line-item includes all of the indirect costs charged to County departments.
- The County continues to receive $550,038 in lottery revenue from the state.

Special Revenues

Jail District

- The County Jail District was initially approved by voters in 1997. In September 2006, the voters approved the County's request to increase the jail sales tax rate from a $^3/_{10}$-cent rate to a ½-cent, which went into effect on January 1, 2007. In addition, the Jail District sales tax was extended 15 years, which will now sunset in 2027.
- Total budgeted Jail District revenues in FY 2015 are up $5,821 to $14,310,140.
- The MOE payment increased $26,078, from $2,518,950 to $2,545,028.
- The operating budget increased $3,661,066 (25.9%), from $14,145,802 to $17,806,868.
- **Jail facilities**
  - **Juvenile**: The juvenile facility currently holds 34 beds. The County can potentially rent beds to the Federal Marshals at $265/day; however, revenue from renting beds was not collected or budgeted over the last four years. Last year, the average occupancy of the facility was 19.
  - **Adult Detention**: The Flagstaff Detention Facility holds 596 beds (the County attempts to maintain an average occupancy of approximately 80%) and the Page facility holds 48 beds. The County rents beds to the Bureau of Indian Affairs (BIA), the Federal Bureau of Prisons (BOP), and the Yavapai County Sheriff's office at $60/day. Revenues in FY 2014 were budgeted at $1,372,179 and dropped to approximately $1 million in FY 2015.
  - In FY 2014, the estimated medical expenses for the Flagstaff and Page facilities were estimated at $706,587.

Parks and Open Space

- At the 2002 General Election, voters approved a $^1/_8$-cent capital projects sales tax for the purpose of implementing the Coconino Parks and Open Space Program. The tax was scheduled to sunset once collections reached $33 million, which County officials expected would occur by September 2014. As a result, the tax rate was repealed effective October 1, 2014.
- The sales tax was budgeted at $3,217,556 in FY 2014.
- The FY 2015 budget increased $266,363 (2%), from $13,339,166 to $13,605,529.

Road Fund

- HURF (Public Works) budgeted revenues dropped $238,682 (2.2%), from $10,828,855 to $10,590,173.

- The HURF budget decreased $5,710,159 (24.4%), from $23,429,373 to $17,719,214.

Charges to Special Districts

- Public Health Services District- In FY 2014, the County charged the District $1,358,566 for indirect costs. In FY 2015, the County charged the District $1.3 million.
- Library District - The County does not charge the Library District for indirect costs.
- Jail District - The County charged the District $867,437 in FY 2014, which dropped to $786,036 in FY 2015.
- Flood Control District - The County charged the District $71,630 in FY 2014 and $179,352 in FY 2015.
- Road Fund - The County charged the Fund $907,145 in FY 2014 and $406,036 in FY 2015.

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a 1.5% market adjustment, effective July 1, 2013, and the total impact was $1.050 million ($500,000 to the GF/$550,000 to OF). In addition, the County provided employees with a 2.5% merit raise on their anniversary date for a total cost of $1.7 million ($800,000 to the GF/$900,000 to OF). In FY 2015, the County again awarded employees with a 2.5% merit increase effective on the employee's anniversary date at a total cost of $1.7 million ($800,000 to the GF/$900,000 to OF). The BOS set aside an additional $400,000 in the GF for possible compression mid-year raises for employees, which will be decided by the BOS following the November election (see discussion under *County Road Maintenance Sales Tax Initiative*).
- Budgeted payroll: Budgeted payroll, including EREs, in the GF increased from $35,926,450 to $37,737,946. The budgeted payroll in TF increased from $71,785,709 to $75,007,279.
- Health benefits: The County is the primary contributor to the Northern Arizona Public Employees Benefit Trust while employee contributions are minimal. The County has begun phasing in its wellness program, which offers a $20/month discount to employees who participate in preventive screenings and a healthy lifestyle. In FY 2014, the Health Insurance budget decreased 3.5% ($266,000). There is no increase budgeted for FY 2015.
- Budgeted FTEs: In FY 2015, the GF budgeted FTEs increased 10, from 487 to 497. Total FTEs rose 6, from 1,056 to 1,062.
- Employee vacancy and turnover rates: The turnover rate is approximately 12%. The vacancy rate is currently unknown.

County Road Maintenance Sales Tax Initiative (Prop 403)

Coconino County voters passed Prop 403 at the November 2014 ballot. The measure authorized a 3/10-cent County sales tax rate for maintaining and preserving the conditions of Coconino County roads. The tax will be in effect for 20 years beginning January 1, 2015. The County estimates that the sales tax will raise approximately $7 million a year to fund road maintenance costs, including costs related but not limited to snowplowing, dirt road grading, road surface chip sealing, road maintenance and other road-related expenses.

Capital Projects

The FY 2015 budget includes $2,050,278 in capital projects. Of the total, $757,961 is designated for repairs in the Jail District and the remainder is for various other capital improvement projects. The County is in the planning stages of demolishing the old jail that is not being utilized for its original purpose. The County is also planning to remodel the Page Justice building. The current jail facility is close to capacity; therefore, the County is planning to construct a new building on the existing parcel that will serve as transitional housing and is estimated to cost approximately $3 million.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County does not hold any debt.

GILA COUNTY

Overview

- Gila County's GF budget for FY 2015 is $44,230,262, a $1,801,593 (3.9%) decrease below last year's budget of $46,031,855. This year's decrease was accomplished with $1,342,343 in employee vacancy savings.
- The County's beginning fund balance for this year is $15,766,569, $4,082,328 (21%) less than last year. The fund balance represents 36% of the GF budget.
- The total budget for FY 2015 of $94,444,905 is a decrease of $807,120 (0.8%) below last year's adopted budget of $95,252,025.

Property Values

- The primary NAV decreased 5.14% to $416,099,715. New construction amounted to $10,558,743 (2.54% of total NAV). Secondary NAV is down 4.8% to $419,257,531.

Property Tax Revenues

Primary Levy

- Gila's primary property tax rate remains the same at $4.1900. This year's primary tax rate is $0.3418 below the TNT rate of $4.5318; therefore, the County was not required to hold a TNT hearing.
- The primary levy of $17,434,578 is $943,803 (5%) below last year's levy of $18,378,381.

County Library

- The Library District levy is $838,716, down $41,870 (4.8%) from last year. The tax rate stayed the same at $0.2000.
- The District budget decreased $200,485 (11.3%), from $1,779,558 to $1,579,073.
- The beginning fund balance for FY 2014 was $739,410, which dropped to $630,000 in FY 2015.

GILA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	4.1900	4.1900	0.0000	4.5318	$18,378,381	$17,434,578	-$943,803	-5%
Library	0.2000	0.2000	0.0000		$880,586	$838,716	-$41,870	-5%
OVERALL RATE	**4.3900**	**4.3900**	**0.0000**		**$19,258,967**	**$18,273,294**	**-$985,673**	**-5%**

Other GF Revenues

- Auto in Lieu is up $56,944 (3.8%), from $1,500,000 to $1,556,944.
- State shared sales tax is up $56,150 (1.1%), from $4,900,000 to $4,956,150.
- The County's half-cent sales tax revenue stayed the same at $2,600,000.
- PILT revenue is up slightly to $3,200,905.
- Lottery revenues are budgeted at $550,000 in FY 2015.

Jail Facilities

Adult facility

- The adult facility holds 219 beds and is near max occupancy. The County currently rents beds to other counties at a rate of $54.63/day. Projected revenues in FY 2015 are budgeted at $136,500.

Juvenile facility

- The juvenile facility holds 26 beds. Gila County contracts with the US Marshals for renting beds at $131/day (until recently, the County rented beds to BIA; however, the tribe built their own facility so the County currently receives few if any BIA prisoners). Total revenues from renting beds remain the same at $80,000. The Juvenile Detention budget increased $9,936, from $1,312,349 to $1,322,285.
- In FY 2015, the Sheriff's budget decreased $51,755, from $10,708,918 to $10,657,163.

Special Revenues

Road Budget

- HURF revenues increased $215,152 (7%), from $3,066,000 to $3,281,152.
- VLT dropped slightly to $809,409.
- The County Transportation Sales Tax was scheduled to sunset on December 31, 2014; however, voters approved Prop 404 at the November 2014 ballot, which extended the sales tax another 20 years, effective January 2015. With its passage, the County plans to share the revenues with cities and towns. In FY 2015, the budgeted revenues are anticipated to drop $807,156 (26%) to $2,282,844.
- The total Road Fund budget is up $635,530 (5.4%), from $11,809,197 to $12,444,727.

Charges for Services

- Library District - Beginning in FY 2014, the County charged the District $94,990 for indirect costs. The charges dropped to $54,990 in FY 2015. The County does not charge a per parcel fee for printing and mailing of tax bills like some other counties.
- Road Fund - The County charged the Road Fund $798,767 for indirect costs in FY 2014. In FY 2015, the charges increased to $823,072.

Expenditures

- Employee compensation:
  - The County offers two opportunities each year for employees to receive financial recognition of a one-time payment in December based on the change in CPI or in June based on the employee's performance appraisal score.
  - The County had a classification and compensation study completed in the Spring of 2014, which became effective for FY 2015. As a result, employee salaries increased by an average 6.2% and the total impact to the GF amounted to $1.34 million.
- Budgeted payroll: In FY 2014, the GF budgeted payroll, including EREs, was budgeted at $23.9 million and $36.8 million in TF. In FY 2015, budgeted payroll in the GF decreased to $23.3 million and $36.3 million in TF.
- Health benefits: In FY 2014, the County's health insurance premium costs increased by approximately 2%, which was entirely absorbed by the County ($65,406 to the GF/$24,902 to OF). In FY 2015, health insurance premiums costs increased 2.8%, which was entirely absorbed by the County GF ($129,000 impact). The County currently pays 93% for employee coverage and 60% for dependents, depending on the level of benefits.
- Budgeted FTEs: In FY 2014, GF FTEs were down 5 to 413 and FTEs in TF were down 15 to 660. In FY 2015, GF FTEs dropped 9 to 404 and total fund FTEs dropped by 8 to 652.
- Employee vacancy & turnover rates: In FY 2015, the GF budget included a line item titled "vacancy savings" that amounted to $1,342,343 and represented 3.8% of the GF budgeted expenditures. The voluntary turnover rate remains at approximately 20%.
- Enterprise Funds: The budgeted expenditures increased from $3,405,826 in FY 2014 to $4,649,764 in FY 2015. Of that amount, $2,608,354 is dedicated for recycling and landfill management, $1,991,410 for the Russell Gulch expansion, and $50,000 for Buckhead Mesa expansion.

Capital Projects

In FY 2015, the capital projects budget increased from $2,720,100 to $3,216,162 (non-capitalized projects not included). Some of the major capital improvement projects are as follows: $648,612 for the Globe Courthouse remodel/repairs; $196,400 for the Globe Jail bldg repairs/parking lot repaving; $386,750 for the Payson Jail remodel/parking lot repaving; $500,000 to construct an Animal Control building in Globe (joint project with city); $111,080 for the Payson Chamber remodel; and $129,000 for the Payson Courthouse steps & landings. The budget also includes $408,400 in Court security projects and $483,946 in bond building projects.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, there is $6,575,000 outstanding in revenue bonds. During FY 2010, the County borrowed $8 million in revenue bonds over 20 years for the construction of the new Public Works facilities, expansion of its jail facilities, and a new evidence storage facility for the Sheriff's office. The budgeted debt service payment stayed the same for FY 2015 at $628,150. The County also held $33,970 in lease-purchase debt.

GRAHAM COUNTY

Overview

- Graham County's GF budget for FY 2015 is $21,270,214, an increase of $334,776 (1.6%) from $20,935,438 in FY 2014.
- The County's beginning fund balance is $1,926,170, up $657,877 (51.9%) over last year's fund balance. The fund balance represents 9.1% of the total GF budget.
- The County's total budget of $33,523,198 is an increase of $631,956 (1.9%) over last year's total budget of $32,891,242.

Property Values

- In FY 2015, the primary NAV increased 10% to $211,469,611. New construction amounted to $2,320,858 (1.1% of total NAV). Secondary NAV is up 10% to $213,508,436.

Property Tax Revenues

Primary Levy

- The primary tax rate decreased $0.1917, from $2.3711 to $2.1794, which is the County's TNT rate.
- The County's primary levy is $4,608,769, which is an increase of $50,551 (1.1%) over last year's levy of $4,558,218.

Flood Control District

- The District's NAV increased $12,254,579 (6.4%), from $191,000,605 to $203,255,184.
- The District rate stayed the same at $0.0953.
- The levy for the District increased $11,678 (6%), from $182,024 to $193,702.
- The budget increased $47,675 (11.7%), from $408,959 to $456,634 (actual expenditures for FY 2014 amounted to $106,738).
- The beginning fund balance in FY 2014 was $226,435. The FY 2015 beginning fund balance is up $36,000 to $262,332.

GRAHAM COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	2.3711	2.1794	-0.1917	2.1794	$4,558,218	$4,608,769	$50,551	1%
Flood Control	0.0953	0.0953	0.0000		$182,024	$193,702	$11,678	6%
OVERALL RATE	**2.4664**	**2.2747**	**-0.1917**		**$4,740,242**	**$4,802,471**	**$62,229**	**1%**

Other GF Revenues

- PILT increased $141,708 (5.4%), from $2,636,873 to $2,778,581.
- State shared sales tax stayed the same at $4,000,000.
- The half-cent sales tax revenues remain the same at $2,000,000.
- Auto in Lieu is up $59,717 (7.2%), from $825,000 to $884,717.
- The County continues to receive $550,000 in state Lottery revenues.
- The County received an additional legislative appropriation of $500,000 in FY 2015.

Jail facilities:

- Juvenile facility: The juvenile facility holds 48 beds. The County budgeted $750,000 for renting beds to other jurisdictions ($500,000 from BOP and $250,000 from USM). The County continues to charge Greenlee County $250,000 for utilizing up to three beds. The budget for regional juvenile detention increased from $1,461,125 to $1,470,456.
- Adult facility: The current adult facility holds a maximum of approximately 200 beds. The County rents beds to the state at $38/day and to cities at a rate of $50/day. Budgeted revenue from renting beds in FY 2015 is $67,000. The average occupancy was 82%.

- In situations of overcrowding, the County sends its female prisoners to Greenlee County at a cost of $50/day, which is budgeted at $30,000 in FY 2015.
- Budgeted medical costs in the jail facilities amounted to $481,757 in FY 2014 and increased to $531,117 in FY 2015 ($20,000 for the purchase of new medical records software). The medical care is provided by an in-house nurse (four nurses on rotation).
- The Sheriff's budget (GF only) increased $142,893 (2.4%), from $6,044,573 to $6,187,466.

Special Revenues

Road Fund

- HURF revenue increased $39,152 (1.3%), from $2,950,000 to $2,989,152.
- In FY 2015, forest fee revenues decreased $10,568 (1.8%), from $585,568 to $575,000.
- The Road Fund budget increased $210,622 (3.4%), from $6,212,465 to $6,423,087 (estimated actual expenditures for FY 2014 were $3,344,001).

Charges to Special Districts

- Flood Control District -The County charged the District $74,588 in FY 2014 and $78,977 in FY 2015.
- Road Fund - The County charged the Road Fund $372,556 in FY 2014 and $346,463 in FY 2015.

Expenditures

- Employee compensation: In FY 2014, the County budgeted only for longevity raises at a total cost of $53,000 ($38,000 to the GF/$15,000 to OF). Longevity raises of 4% are awarded to employees at one-year of employment, two years, five years, and every third year beyond that point. In FY 2015, longevity raises amounted to a total impact of $78,000 ($46,000 to the GF/$32,000 to OF). In addition, the County awarded employees with a 4% average market adjustment at a total cost of $483,000 ($300,000 to the GF/$183,000 to OF).
- Budgeted payroll: In FY 2015, the GF budgeted payroll, including EREs, increased from $11,220,582 to $11,221,316. Total payroll decreased from $15,460,195 to $15,384,797.
- Health benefits: The County is part of the six-county insurance pool and charges employees with single coverage of $100/month and employees with family coverage of $300/month. The County pays approximately 90% for single coverage and 78% for family coverage. The County has implemented a health risk analysis and encourages employees to fill out the assessment or pay a $10/pay period penalty for failure to do so. In FY 2015, health insurance costs increased approximately 2%, which was absorbed by the County ($29,000 to the GF/$12,000 to OF).
- Budgeted FTEs: The FY 2015 FTEs in the GF are budgeted at 187 and 260 total FTEs.
- Employee vacancy & turnover rates: The most recent calculation reflects that the employee vacancy rate is approximately 10% and the turnover rate is 23%, primarily in Detention.

Capital Projects/Debt

The capital projects budget remained the same in FY 2015 at just $75,000.
According to the Department of Revenue FY 2014 Report of Bonded Indebtedness, the County held $1,095,769 in lease-purchase debt.

Jail District Measure - November 2014 Ballot

Voters narrowly approved the creation of a Jail District in Graham County at the November 2014 ballot. As a result, the County will levy a half-cent sales tax effective July 1, 2015 for 25 years. The sales tax is expected to generate $2 million each year. County officials claim the creation of the District was necessary because existing facilities are dilapidated and are not sufficient to hold the current and anticipated inmate population (The current facility houses up to 125 inmates with the ability to hold up to 200 beds). The plan is to build a 250-bed jail with the ability to expand. The County expects the facility to cost approximately $25 million and would take up to four years to complete.

GREENLEE COUNTY

Overview

- Greenlee's GF budget for FY 2015 is $11,562,861, representing an increase of $943,020 (8.9%).
- The County GF budget reflects a cash balance of $3,532,504; however, the budgeted cash balance is understated by nearly $3 million. It is estimated that the actual cash balance is approximately $7.5 million (the County's FY 2013 financial audit showed the County held $9.4 million in its GF balance but the County budget only reflected $3.8 million at the time).
- The total budget (total financial resources) for FY 2015 is $25,130,309, an increase of $1,558,209 (6.6%) over the FY 2014 total budget of $23,572,100. The FY 2015 budgeted expenditures are $23,979,451.

Property Values

- The primary NAV increased 36.6% to $458,425,787. New construction amounted to $658,083 (0.14% of total NAV). The Secondary NAV increased 37.6% to $462,439,380.

Property Tax Revenues

Primary Levy

- Greenlee County adopted a primary tax rate of $0.5500, which is just below the County's maximum tax rate of $0.5559. This year's rate exceeded the TNT rate of $0.5390; therefore, the County was required to hold a TNT hearing and publish a notice of the tax increase.
- Although the County's primary tax rate dropped to $0.5500, the levy increased $43,190 (2%) as a result of the 36.6% increase in the PNAV.

Public Health Services District

- In June 2006, the County BOS created the District by unanimous vote of the Board. The tax rate increased $0.0219 this year, from $0.2081 to $0.2300 (the maximum tax rate allowed by statute is $0.2500). As a result of the tax rate increase combined with the 37% growth in secondary value, the levy increased $363,883 (52%) to $1,063,611.
- The County uses the Public Health Services District fund to pay for health department services, animal control, inmate medical expenses, and ambulance services. The expenses for inmate medical expenses include nurses' salaries.
- The District budget increased $85,244 (4.6%), from $1,869,196 to $1,954,440.
- The MOE payment for the District is $356,000.

Flood Control District

- The District's NAV increased $2,932,654 (5.5%), from $53,254,826 to $56,187,480.
- The District's tax rate increased $0.0253, from $0.1647 to $0.1900. The levy increased $19,076 (22%), from $87,672 to $106,748.
- The District budget is down $17,000 (9.8%), from $174,000 to $157,000.

GREENLEE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.7350	0.5500	-0.1850	0.5390	$2,478,151	$2,521,341	$43,190	2%
Public Health Services	0.2081	0.2300	0.0219		$699,728	$1,063,611	$363,883	52%
Flood Control	0.1647	0.1900	0.0253		$87,672	$106,748	$19,076	22%
OVERALL RATE	**1.1078**	**0.9700**	**-0.1378**		**$3,265,551**	**$3,691,700**	**$426,149**	**13%**

Other GF Revenues

- Auto in Lieu remains the same at $325,000.
- The half-cent sales tax revenue stayed the same at $1,200,000 (actual FY 2014 revenues were $2,397,110).
- State shared sales tax revenue dropped $150,000 (3.3%), from $4,500,000 to $4,350,000 (FY 2014 actual revenues were $4,898,988. DOR estimates the County should receive $5,778,000 in state shared revenues in FY 2015).

- PILT is down $238,501 (30%), from $783,176 to $544,675 (FY 2014 actual revenues were $844,890).
- The County budgeted to receive $574,500 from the state for out-of-county tuition, which is up $191,700 (50%) from last year.
- The County continues to receive $550,000 in Lottery revenues from the state.

Special Revenue Funds

- Road fund revenue increased $130,000 (14.8%), from $880,000 to $1,010,000. The budget increased $330,000 (16.7%), from $1,980,000 to $2,310,000.
- National forest fee revenues stayed the same at $600,000. The County distributes $300,000 to both the schools and the Road Fund.

Charges to Special Districts

The County does not charge its special districts for reimbursement of services.

Expenditures

- In FY 2014, the County provided all employees with a 3.5% increase (increased pay scale by 1%, plus shifted all employees up one grade), effective September 1, 2013. Deputy Sheriff's received an additional 1.5% increase, effective July 1, 2013, at a total estimated annualized cost of $330,000 ($220,000 to the GF). In FY 2015, the County awarded employees with a 3% increase, effective September 1. The total estimated annualized cost, including EREs, is $280,000 ($180,000 to the GF).
- Budgeted payroll: In FY 2014, GF budgeted payroll, including employee related expenses (EREs), increased from $5,772,347 to $6,106,476. Total payroll increased from $8,863,964 to $9,380,466. In FY 2015, the GF budgeted payroll increased $655,408 (10.7%) to $6,761,884. Total budgeted payroll increased $680,294 (7.3%) to $10,060,750.
- Health benefits: In FY 2014, health premium costs increased 3% in FY 2014 and the County planned to share the cost with employees. The County currently covers 94% for employee coverage and 82% for dependents. In FY 2015, health premiums costs increased 2%, which will be entirely absorbed by the County at a total estimated cost of $107,142 ($96,428 to the GF).
- Budgeted FTEs: In FY 2014, the budgeted FTEs in the GF dropped from 101 to 92 and total FTEs decreased from 165 to 160. In FY 2015, GF FTEs increased back up to 101 and total fund FTEs increased to 168.
- Employee vacancy & turnover rates: The current employee vacancy rate is 2.5% and the turnover rate is 18%.
- Jail facilities: The County uses Gila Health Resources to control its inmate costs, which amounted to $87,410 in FY 2013. Also to control costs, the County has an ambulance service that it uses to avoid using a helicopter for emergencies. There are 55 beds in the adult facility and the facility is close to full capacity. The County does not have a facility to hold its juvenile inmates and instead transfers its juveniles to Graham County at an annual cost of approximately $250,000 by renting up to three beds.
- In FY 2015, the Sheriff's budgeted expenditures increased $481,458 (15.8%), from $3,056,666 to $3,538,124.

Debt

The Department of Revenue's FY 2014 Report of Bonded Indebtedness shows that the County held $2,286,459 in lease-purchase debt (the debt is for vehicles and equipment in the Road Department). The budgeted debt service payment in FY 2015 is $700,000.

Capital Projects

The capital projects budget increased $1,900,000 (127%), from $1,500,000 to $3,400,000.
The County budgeted for several projects, which include the following:

- New Duncan Annex building: total estimated cost of $1,900,000 (scheduled completion TBD).

- Greenlee County Airport: $335,000 to construct airport drainage/erosion control improvements (5-year project).
- Public Works: $259,000 (2-year project).
- Correctional Facility: The current correctional facility has been in use for 35 years and is in need of numerous repairs. A firm has provided the County with three options: 1) basic renovation ($1,056,000); 2) Fully renovate, replace deficient systems and building elements with new technology ($3,950,000); and 3) Replace facility ($5.5 million). Funding sources are currently being reviewed.

LA PAZ COUNTY

Overview

- La Paz's GF budget for FY 2015 is $16,838,277, an increase of $519,752 (3.2%) from the FY 2014 GF budget of $16,318,525.
- The County's FY 2015 GF beginning balance is $1,868,393.
- The FY 2015 total financial resources are $32,040,614, a decrease of $996,036 (3%) from last year's total budget of $33,036,650. Of the total financial resources, the County had budgeted $31,415,184 in total expenditures.

Property Values

- The primary NAV decreased 5.1% to $205,814,389. New construction amounted to $4,744,214 (2.31% of total NAV). The secondary NAV dropped 6.2% to $210,720,562.

Property Tax Revenues

Primary Levy

- La Paz County's primary tax rate increased $0.3255, from $1.9608 to $2.2863, which is the County's maximum tax rate. Since the County's adopted tax rate exceeded the TNT rate of $2.1145, the County was required to publish a notice and hold a public hearing regarding the tax increase.
- La Paz County's primary property tax levy is $4,705,534, which is $453,826 (10.7%) more than last year and is the maximum allowable constitutional levy.

LA PAZ COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.9608	2.2863	0.3255	2.1145	$4,251,708	$4,705,534	$453,826	11%

Other GF Revenues

- Auto in Lieu remains stable at $572,581. In FY 2015, the County began accounting for the Auto in Lieu revenues that were previously listed under the Road Fund under the GF. The amount budgeted in FY 2015 increased $26,128 (6%) to $456,987.
- State shared sales tax revenue dropped $148,000 (6.2%), from $2,400,000 to $2,252,000.
- Half-cent sales tax revenues increased $258,884 (22.4%), from $1,153,689 to $1,412,573.
- PILT is up $128,209 (7.1%) to $1,928,209.
- The County receives $550,000 in Lottery revenue from the state.
- Sanitation charges increased $1,320,000 (165%), from $800,000 to $2,120,000.
- Indirect cost revenues are budgeted at $500,000 in FY 2015.
- Other miscellaneous revenues remain the same at $100,000.

Special Revenues

Road Fund

- HURF revenue increased $163,547 (4.7%), from $3,480,632 to $3,644,179.
- The Public Works budget is down $416,005 (10.7%), from $3,885,750 to $3,469,745.

Enterprise Fund

- The revenues from the La Paz County Golf Course increased $101,777 (6.4%), from $1,583,183 to $1,684,940. The budget changed by the same amount.

Jail District

- The County levies a ½-cent sales tax to support its Jail District. Total revenues budgeted in the Jail District increased $138,700 (4.3%), from $3,200,000 to $3,338,700. The Jail District includes $1,350,000 in intergovernmental revenues from the housing of Federal and Coconino County inmates. The County rents beds to the US Marshals and ICE at a rate of $60/day (up from the previous $44/day charge) and currently house approximately 50 federal inmates on average. Beds are also rented to Lake Havasu, Kingman, and Mohave County at $65/day and to the Colorado River Indian Tribes and private entities at $65/day. The Jail District ½-cent excise tax is up $138,200 (12.2%), from $1,130,000 to $1,268,200.

- The District operations budget increased $155,392 (5%), from $3,134,608 to $3,290,000. The personnel costs in the District, including EREs, were budgeted at $2,092,525 in FY 2014. In FY 2015, total personnel costs in the Jail District increased to $2,209,989. There are currently 38 FTEs funded by the District.
- The County's MOE payment stayed the same in FY 2015 at $720,000.
- The adult facility holds 266 beds the average daily bed occupancy remains at approximately 135.
- The County does not currently have a juvenile facility, and instead, transfers its juveniles to Yuma County. Yuma County charges La Paz $80/day, which was budgeted at $50,000 in FY 2014.
- In FY 2015, the budget includes a lease purchase payment of $42,000.

Yakima Judgment/Bonds

With the passage of SB1178 in the 2011 legislative session, the County was authorized to issue TPT-funded bonds to pay its $14 million judgment to Yakima. The amount budgeted, not to exceed $19 million, includes the judgment, 2% underwriting fees, bond counsel fees, and charges for the bond issuance. The half-cent sales tax took effect on December 1, 2011. The tax is estimated to be in effect for twenty years.

- In FY 2015, the revenue generated from the sales tax for the judgment is down slightly to $2,179,576.
- The debt service payment for the bonds in FY 2015 is $1,500,000.

Expenditures

- Employee compensation: The County did not award pay raises in FY 2014. In FY 2015, the County awarded employees with a 3% COLA. The total impact amounted to approximately $500,000 ($250,000 impact to the GF).
- Budgeted payroll: The GF budgeted employee compensation in FY 2014 was $8,468,211 and budgeted employee compensation in TF was $14,291,688. In FY 2015, budgeted compensation in the GF increased to $8,827,465 and to $17,298,288 in TF (Includes $2,209,989 budgeted employee compensation in the Jail District).
- Health benefits: The County covers 100% of health benefit costs for employees and 50% for dependents.
- Budgeted FTEs: In FY 2014, the GF budgeted FTEs were 131 and TF FTEs were 278 (Includes an estimated 38 FTEs in the Jail District). In FY 2015, FTEs in the GF are budgeted at 130 and FTEs in TF are up to 289 (Includes 38 FTEs budgeted in the Jail District).
- Employee vacancy & turnover rates: The most recent data supplied by the County showed that the employee vacancy rate was 3.48% and the employee turnover rate was 13.2%.

Debt

According to the Department of Revenues FY 2014 Report of Bonded Indebtedness, the County held $18,760,000 in revenue bonds for the Yakima judgment. In addition, the County issued $2.022 million in COPs in 2007, financed over ten years, for the jail expansion. This debt was recently refinanced and the current outstanding debt is $1,585,000.

In addition, the Jail District held $1,585,000 in outstanding lease-purchase debt. The County held $93,699 in lease-purchase debt at the end of FY 2014.

MARICOPA COUNTY

Overview

- The GF budget increased $73,120,683 (7.8%), from $942,780,433 to $1,015,901,116.
- The GF balance decreased $116,354,517 (51%), from $230,066,825 to $113,712,308. The fund balance represents 11.2% of the GF budget.
- The County reports its total financial resources available at $3,060,728,490, which is down $4,665,038 (0.2%) from last year. Of the total financial resources, the County only budgeted to spend $2,309,530,514 in FY 2015 (75.7% of its total budgeted financial resources).

Property Values

- The County's primary NAV rose 4.8% to $33,519,795,354. New construction amounted to $701,381,830 (2.09% of total NAV). Secondary NAV increased 8.8% to $35,079,646,593.

Property Tax Revenues

Primary Levy

- The primary tax rate for Maricopa County increased $0.0402, from $1.2807 to $1.3209, which exceeded the $1.2486 TNT rate by $0.0723. As a result, the County was required to publish notice and hold a public hearing regarding the tax increase.
- The primary levy increased $32,987,580 (8.1%), from $409,775,397 to $442,762,977.

Library District

- The Library District's levy for FY 2015 is up $5,387,979 (38.2%), from $14,116,305 to $19,504,284. The secondary tax rate increased $0.0118, from $0.0438 to $0.0556.
- The Library District budget decreased $298,522 (1.2%), from $25,525,017 to $25,226,495.
- In FY 2014, the County's Library District beginning fund balance was $15,224,924. In FY 2015, the fund balance is $13,118,288.

Flood Control District

- The District's NAV increased $2,742,347,280 (9.6%), from $28,622,833,869 to $31,365,181,149.
- The FY 2015 levy is $43,660,332, a $3,817,347 (9.6%) increase above last year's levy. The tax rate remained the same at $0.1392.
- In the FY 2014 budget, the District began the year with a fund balance of $52,843,453. The district began FY 2015 with a $51,986,081 fund balance.
- The budget increased slightly, from $72,009,409 to $72,495,393. The FY 2015 District budget includes $40 million in capital projects, same as last year.

Stadium District

- Total revenue in the district increased from $10,334,868 to $10,458,111. Sales tax revenues remain the same at $4,997,042. License & permit revenues increased from $3,384,928 to $3,422,385. Other charges are up from $1,144,722 to $1,254,260.
- The FY 2015 Stadium District budget is $8,689,186, down $2,642,512 (23.3%) below last year's budget. Included in the budget is $2,985,808 for District operations, $3,700,378 for debt service, and $2,003,000 in reserves for long-term projects.
- In FY 2014, the District began the year with $27,316,604. The beginning fund balance in FY 2015 is $22,803,193.

MARICOPA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.2807	1.3209	0.0402	1.2486	$409,775,397	$442,762,977	$32,987,580	8%
Library	0.0438	0.0556	0.0118		$14,116,305	$19,504,284	$5,387,979	38%
Flood Control	0.1392	0.1392	0.0000		$39,842,985	$43,660,332	$3,817,347	10%
OVERALL RATE	**1.4637**	**1.5157**	**0.0520**		**$463,734,687**	**$505,927,593**	**$42,192,906**	**9%**

Other GF Revenues

- State shared sales taxes increased $27,897,879 (6.4%), from $437,402,846 to $465,300,725.
- State shared vehicle license tax increased $13,109,877 (10.9%), from $119,748,223 to $132,858,100.
- PILT is up $368,401 (3.1%), from $11,972,067 to $12,340,468.

Special Revenues

Jail Sales Tax

- Jail Sales tax revenue increased $10,189,460 (7.8%), from $131,106,321 in FY 2014 to $141,295,781 in FY 2015. The MOE payment in FY 2015 is $176,801,288.
- The County charges cities & towns a booking fee of $266.41 and per diem of $81.85 for housing inmates in the County jail facilities. The FY 2015 booking and per diem revenues were budgeted at $31,016,456.
- In FY 2015, the total budget for the Sheriff's office increased $42,342,487 (14.2%), from $298,336,365 to $340,678,852.

Jail facilities

In October 2013, the U.S. District Court for Arizona issued a Judgment Order in the Melendres v. Arpaio case. The Judgment Order stated requirements which MCSO must follow in order to comply with the court ruling. In April 2014, the Judgment Order was amended to make the Court Monitor responsible for Community Outreach rather than MCSO. The total implementation costs budgeted for the judgment amounted to $7,687,376 in FY 2014. The FY 2015 MCSO GF budget includes $8,310,737 for operating costs and $4,200,000 for non-recurring costs for the purchase of vehicle mounted cameras. Non-Departmental budget includes $2,825,000 in operating costs for the Court Appointed Monitor and other judgment related charges. The budget for the MCSO operating costs and the monitor are $11 million for the year.

Additional funding was provided for General and Detention Non-Recurring costs: Airplane ($850,000); Helicopter ($5,000,000); Camera Security System ($247,978); Records Management System ($675,000);

- **Adult facilities**: The adult facilities hold up to 11,509 beds (includes triple-bunking, portable beds, and beds in "tent city"). According to the recently completed Jail Master Plan, functional capacity is 7,398. Average occupancy is approximately 8,100 inmates. Maricopa County does not rent beds to other jurisdictions.
- **Juvenile facilities**: The juvenile facilities hold up to 406 beds; however, the current staffing levels assume 187 beds. The most recently calculated average daily population is 169 as of October 2014.
- In FY 2015, the budget for correctional health services increased from $58,281,681 to $61,409,512.

Highway & Transportation Revenue

- Revenue in the Road Fund in FY 2015 is up $11,212,552 (11.8%), from $94,767,838 to $105,980,390.
- In FY 2015, the Transportation Operations budget is up from $140,961,689 to $145,000,754. Included in this year's budget is $61,737,434 for operations and $82,578,500 for capital projects.

Elderly Assistance Fund (EAF)

- The EAF is unique to only Maricopa County in which the revenues are derived from the 16% interest paid for the redemption on property tax liens. The revenues in the Fund are applied by the County Treasurer to property that qualifies under the Senior Valuation Freeze to offset school primary property taxes.
- The fund balance in the EAF as of 5/31/14 was $16,268,808.
- In FY 2013, assistance from the fund was applied to 10,659 parcels and 10,088 in FY 2014. The FY 2014 distributions totaled over $2.3 million.

Charges to Special Districts

The County charges the following amounts for the reimbursement of indirect costs to the GF:

- Library District - In FY 2014, the County transferred $1,085,301 from the Library District to the GF and $1,149,371 in FY 2015.
- Flood Control District - In FY 2014, the County charged the District $1,592,089, which increased to $1,730,641 in FY 2015.
- Stadium District - The County charged the Stadium District $49,326 in FY 2014 and $36,293 in FY 2015.
- Transportation Fund - Charges to the Transportation Fund in FY 2014 amounted to $2,395,364, which increased to 2,788,047 in FY 2015.

Expenditures

- Employee compensation:
  - In FY 2014, the County budgeted for an employee pay-for-performance (PFP) compensation plan, which was funded at approximately 5% on average (effective 7/8/13). The County also reviewed various positions for market equity and adjusted salaries accordingly (areas that have a lot of overtime, such as the attorney's office, IT, healthcare providers, etc.). The total impact of the County compensation plan was estimated at $67 million ($40 million to the GF/$19 million to the Detention Fund/$7.7 million to OF).
  - In FY 2015, the County budgeted for an average 2.5% salary increase for employees at a total cost of $20,650,600 ($10,841,809 to the GF/$4,908,790 to the Detention Fund/$4.9 million to OF). In addition, the County authorized market adjustments for select positions: MCSO deputies and sergeants ($2.5 million to the GF and DT); probation officers and supervisors ($2.2 million GF/$964,000 DT); mental health professionals ($35,000 GF/$160,000 DT); and epidemiologists ($41,000 GF). Also, the County budgeted $1 million for continuation of its Education Assistance Program.
- Budgeted payroll: In FY 2014, GF budgeted payroll, including EREs, was $477,099,455 and TF payroll was $980,349,684. In FY 2015, the GF budgeted payroll increased to $519,517,084 and TF budgeted payroll increased to $1,064,973,183.
- Health benefits: Maricopa County is self-insured for employee health benefits and charges each department a composite rate for each employee ($8,904/year).
- Budgeted FTEs: In FY 2014, budgeted FTEs in the GF were 7,339 and total budgeted FTEs were 14,423. In FY 2015, FTEs in the GF increased to 7,620 and TF FTEs increased to 14,812.
- Employee vacancy & turnover rates: The budgeted employee vacancy rate is approximately 5%. The voluntary turnover rate was projected at 8.4% in FY 2014.

Capital Projects

Maricopa County's Capital Improvement Program (CIP) is a modified "pay as you go" policy in which the County funds its projects with a combination of cash reserves and lease revenue bonds.

In the FY 2015 budget, the County is planning to spend $279 million on the following capital projects:

Transportation ($82,578,500): Bridge construction/preservation ($525,000); County arterials ($14,840,000); Dust mitigation ($3,160,000); Intelligent Trans. Syst. ITS ($2,175,000); MAG ALCP projects ($23,400,000); Partnership support ($1,577,500); Pavement const/preservation ($15,912,000); Right-of-way ($180,000); Safety projects ($3,155,000); Traffic improvements ($5,047,000); Transportation administration ($10,877,000); Transportation planning ($1,730,000).

Intergovernmental ($127,500): Maricopa Regional Trail System Vulture Mountain Study.

GF ($38,945,102): Chambers building ($1,373,091); Court tower ($1,247,290); East court improvements ($8,513,546); Maricopa Regional Trail System ($582,886); Security building ($2,065,187); Sheriff HQ project

($1,000,000); Southwest Justice Courts ($23,413,814); SWAT covered parking ($706,537); Vulture Mountain ($42,751).

Detention ($5,796,583): 4th Avenue Jail ($2,565,291); Lower Buckeye Jail ($3,231,292).

Technology ($145,754,406): BIX Room Byte Info Exchange ($4,299,455); Computer Aided Mass Appraisal ($4,795,000); County telephone system ($6,473,633); Enterprise data center ($18,738,694); Enterprise Resource Planning System ($16,060,899); Infrastructure refresh phase 1 ($5,000,000); Infrastructure refresh phase 2 ($37,604,275); Internal service delivery system ($350,000); Maximo maintenance management upgrade ($750,000); Public Safety radio system ($40,382,450); Sheriff HQ project IT infra. ($1,500,000); Treasurer Tech System upgrade ($572,448); and Project Reserves ($9,227,552).

Detention Tech. ($40,330,136): CHS electronic health records ($2,450,331); Jail MGMT Info. System ($1,795,563); Jail Security System Upgrade ($11,084,242); Project reserve ($25,000,000).

Debt

At the end of FY 2014, the County held $97,135,000 in revenue bonds, according to the Arizona Department of Revenue's Report of Bonded Indebtedness. The FY 2015 debt service payment is budgeted at $16.8 million.

On August 1, 2012, the Maricopa County Stadium District issued Revenue refunding bonds in the amount of $25,140,000, in which the net proceeds, along with $6,277,014 of Stadium District funds, were used to advance the Revenue refunding bonds series 2002, which mature on June 1, 2019. At the end of FY 2014, the Stadium District had $19,260,000 in total outstanding debt. The FY 2015 budgeted debt service payment is $3.7 million.

MOHAVE COUNTY

Overview

- Mohave County's GF budget increased $4,627,051 (6.1%), from $76,154,008 to $80,781,059.
- The County shows that the GF beginning balance increased $5,834,287 (314%), from $1,860,717 to $7,695,004; however, County officials claim that they actually have $13 million in their beginning fund balance. As in past years, the County continues to ignore the statutory requirement that they show all of their cash.
- The total budget for Mohave County is $252,282,568, which is a decrease of $732,508 (0.3%) below last year's total budget of $253,015,076.

Property Values

- The primary NAV decreased 2.5% to $1,727,793,369. New construction amounted to $23,178,631 (1.34% of total NAV). The secondary NAV dropped 2.9% to $1,757,074,571.

Property Tax Revenues

Primary Levy

- The County maintained its primary tax rate of $1.8196, which is below its TNT rate of $1.8909.
- By keeping the tax rate the same, the County's primary levy dropped $792,955 (2.5%), from $32,231,883 to 31,438,928 as a result of the reduction in property values.

Flood Control District

- The District's NAV decreased $45,384,733 (2.6%), from $1,751,482,173 to $1,706,097,440.
- The County continues to levy a tax rate of $0.5000, the same rate that the County has levied since 1998, which is also the maximum tax rate allowable by statute.
- In FY 2015, the District levy decreased $226,924 (2.6%), from $8,757,411 to $8,530,487.
- The budget decreased $11,250,089 (48.2%), from $23,356,666 to $13,585,755 (Actual FY 2014 expenditures were $13,549,200). The fund balance at the beginning of FY 2015 was $4.6 million.

Library District

- The Library District tax rate stayed the same at $0.3236, which will generate $170,194 (2.9%) less in revenue this year, from $5,856,087 to $5,685,893.
- The budget decreased $2,497,284 (22%), from $11,324,455 to $8,827,171 (Actual FY 2014 expenditures were $5,477,301).
- The FY 2015 fund balance was $5.9 million.

Television District

- Mohave County's TV District was originally created to provide and maintain communication equipment resources for residents. For the first time since 1998, the BOS reduced the tax rate levied for the TV District, from $0.0867 to $0.0700. As a result, the levy decreased $339,031 (21.6%), from $1,568,983 to $1,229,952.
- The District's budget increased $1,063,542 (29.2%), from $3,639,450 to $4,702,992 (Actual FY 2014 expenditures were only $600,723). The amount budgeted for the District is nearly eight times more than the actual amount necessary to fund the District.
- The FY 2015 beginning fund balance in the TV District was $3 million.

MOHAVE COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.8196	1.8196	0.0000	1.8909	$32,231,883	$31,438,928	-$792,955	-2%
Flood Control	0.5000	0.5000	0.0000		$8,757,411	$8,530,487	-$226,924	-3%
Library	0.3236	0.3236	0.0000		$5,856,087	$5,685,893	-$170,194	-3%
T.V.	0.0867	0.0700	-0.0167		$1,568,983	$1,229,952	-$339,031	-22%
OVERALL RATE	**2.7299**	**2.7132**	**-0.0167**		**$48,414,364**	**$46,885,260**	**-$1,529,104**	**-3%**

Other GF Revenues

- State shared sales tax is up $219,000 (1.1%), from $20,300,000 to $20,519,000.
- Auto in Lieu increased $154,105 (2.5%), from $6,054,795 to $6,208,900.
- PILT is up $267,598 (8.5%), from $3,145,032 to $3,412,630.
- The County levies a ¼ -cent sales tax that is used to fund capital projects. In FY 2015, the revenues increased $619,100 (10.6%), from $5,819,100 to $6,438,200.
- The County received $550,000 in lottery revenues in FY 2015 from the state.

Special Revenues

Road Fund

- Revenues in the Road Fund increased $644,447 (5.1%), from $12,650,537 to $13,294,984.
- In FY 2015, the HURF budget increased $1,446,244 (7.7%), from $18,699,893 to $20,146,137. Actual expenditures in FY 2014 were $12,810,332 (69% of the amount budgeted).
- The FY 2015 beginning fund balance in the Road Fund was $14.4 million.

Charges to Special Districts

- In FY 2014, the County transferred $1,177,878 from the special taxing districts to the GF for indirect costs and $1,101,786 in FY 2015, broken down as follows:
  - Flood Control District - FY 2014 = $392,626; FY 2015 = $367,262
  - Library District - FY 2014 = $392,626; FY 2015 = $367,262
  - TV District - FY 2014 = $392,626; FY 2015 = $367,262

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a 2.5% COLA. The total estimated cost of the COLA was $1.7 million ($1 million to the GF). In addition, certain positions in the County were reclassified. Employee pay raises were effective July 1, 2013. In FY 2015, the BOS approved the following salary increases on condition that GF revenues exceed the budget through the first five months of the fiscal year, with an effective date of January 1, 2015: Sheriff's Dispatchers' reclassification ($59,000); Public Defender new office clerk and attorney ($33,000); Legal Defender new secretary ($42,000); Probation Department Lead PO reclassification ($16,600); Procurement Department reclassification ($13,800); and reclassification of a Legal Advocate ($15,700).
- Budgeted payroll: The FY 2014 budgeted payroll, including EREs, in the GF was $46,192,354. The budgeted payroll for TF amounted to $80,108,507. In FY 2015, the GF budgeted payroll is $46,427,746. The TF budgeted payroll dropped slightly to $79,510,772.
- Budgeted FTEs: In FY 2014, the County budgeted for 711 FTEs in the GF and 1,272 in TF. In FY 2015, the GF FTEs increased to 717 and TF FTEs increased to 1,275.
- Jail facilities: The County built a new jail which opened in December 2010. The total cost of the project was $72 million, with the majority financed through a 15-year lease purchase agreement ($25.5 million was dedicated from the County's ¼-cent sales tax). The facility has 242,000 square feet and holds 688 beds, with the ability to expand up to 850 beds upon the completion of an unfinished pod, with maximum future expansion up to 1,400 beds. The FY 2015 budget for the jail amounted to $11,921,669, which includes 150 FTEs.

Capital Projects

The budget for capital projects in FY 2015 increased from $4,174,593 to $5,239,855.

Debt

Based on the Arizona Department of Revenue FY 2014 Report of Bonded Indebtedness, Mohave County held $25,390,000 in outstanding revenue bonds, which was used to construct the jail facilities. The County recently paid the $9 million previously held in COPs that funded construction of the County administration building.

NAVAJO COUNTY

Overview

- Navajo County's GF budget in FY 2015 increased $2,559,744 (6.4%), from $39,984,750 to $42,544,494.
- The GF beginning balance in FY 2015 is up $300,000 (7.5%), from $4 million to $4.3 million. The fund balance represents 10% of the total GF.
- The County's total budget is up $2,258,988 (1.9%), from $118,533,913 to $120,792,901.

Property Values

- The primary NAV in Navajo County dropped 6.5% to $845,018,236. New construction amounted to $9,347,135 (1.11% of total NAV). Secondary NAV dropped 6.5% to $846,247,083.

Property Tax Revenues

Primary Levy

- The County adopted the maximum tax rate of $0.8185, which is $0.1190 more than last year's tax rate and $0.0624 above the TNT rate of $0.7561. As a result, the County was required to hold a TNT hearing and publish a notice of the tax increase.
- The County levied the maximum tax of $6,916,474, which resulted in $597,921 (9.5%) in additional revenue for the County.

Flood Control District

- The District's NAV decreased $57,196,933 (9%), from $638,564,841 to $581,367,908.
- The tax rate remained the same at $0.3000 in FY 2015 and generated a levy of $1,744,104, $171,591 (9%) less than last year.
- The budget decreased $250,982 (3.1%), from $7,975,948 to $7,724,966.
- The District began FY 2015 with a $7 million fund balance. The County is building up the District fund balance for the repair of the Winslow levee, which is currently in the design phase. The County anticipates the cost to repair is approximately $60 million, in which 34% will be funded by the County and 66% by the Army Corps of Engineers. County officials do not expect construction to commence for another five to seven years.

Library District

- The County increased the Library District tax rate nearly 3 cents to $0.1000. The levy of $846,247 represents an increase of $209,792 (33%) over last year's levy.
- The Library District budget increased $227,545 (38%), from $598,644 to $826,189 (includes $23,000 in state grants and $60,000 from First Things First Early Childhood Literacy).
- The District began FY 2015 with a zero fund balance.

Public Health Services District

- The BOS established the District by unanimous vote of the Board in 2002. In FY 2015, the tax rate increased nearly 3 cents, from $0.2151 to $0.2430 (the statutory rate cap is 25 cents). The levy increased $110,746 (5.7%), from $1,945,634 to $2,056,380. The MOE payment is $211,175.
- The budget (operations only) increased slightly from $1,529,701 to $1,534,083.
- The District began FY 2014 with a $600,000 fund balance. In FY 2015, the beginning fund balance is $350,000.

NAVAJO COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	0.6995	0.8185	0.1190	0.7561	$6,318,553	$6,916,474	$597,921	9%
Flood Control	0.3000	0.3000	0.0000		$1,915,695	$1,744,104	-$171,591	-9%
Library	0.0704	0.1000	0.0296		$636,455	$846,247	$209,792	33%
Public Health Services	0.2151	0.2430	0.0279		$1,945,634	$2,056,380	$110,746	6%
OVERALL RATE	**1.2850**	**1.4615**	**0.1765**		**$10,816,337**	**$11,563,205**	**$746,868**	7%

Other GF Revenues

- Auto in Lieu increased $35,295 (1.7%), from $2,031,705 to $2,067,000.
- State shared sales tax is up $731,335 (7.1%), from $10,314,665 to $11,046,000.
- Half-cent sales tax increased $604,161 (9.7%), from $6,211,839 to $6,816,000.
- In FY 2014, the County budgeted $983,382 in PILT revenue; however PILT is not included in the FY 2015 budget (actual revenues in FY 2014 amounted to $1,519,256).
- The County continues to receive $550,000 in lottery revenues from the state (included in the "other governmental" budget).

Special Revenues

Road Fund

- HURF revenue increased $790,152 (11.6%), from $6,782,564 to $7,572,716.
- Auto in Lieu decreased $24,697 (1.2%), from $2,140,407 to $2,115,710.
- The Public Works/HURF budget increased $299,216 (1.8%), from $16,760,175 to $17,059,391.

Jail Facilities

Adult facilities: The County adult jail facilities hold approximately 500 beds between the Holbrook and Show Low complexes and the average daily inmate population is 220. During FY 2014, the County expanded its facilities by adding space for a kitchen, laundry facilities, and medical examinations.

- **Budgeted Revenues:** In FY 2013, the County began charging municipalities for bed rentals at half of the federal rate for three years. In FY 2015, the County budgeted to receive $547,000 in revenue as a result. The County recently lost its contract to house inmates with the U.S. Marshals. The County recently entered into a new five-year contract with BIA for up to $2 million/year to house up to 100 inmates at $55/inmate day. In FY 2015, the County anticipates receiving $264,556 in revenue for housing BIA prisoners.
- The FY 2015 total budgeted expenditures for jail operations amount to $6,272,376 (GF budget is $4,088,334). Total medical costs in the jail facilities in FY 2014 were budgeted at approximately $210,000 and increased to $247,000 in FY 2015.

Juvenile Detention: The Juvenile Detention facility houses up to 40 beds and the average occupancy is 12. The County contracts with BIA for housing juvenile inmates at $130/day. In FY 2015, the County budgeted to receive $113,000 in revenues from BIA.

- The Juvenile Detention Fund budget is up $23,033 (2%), from $1,146,685 to $1,169,718 (GF budget is $1,139,081).

Charges to Special Districts

- Flood Control District - In FY 2014, the County transferred $214,528 from the District to the County GF for reimbursement of indirect services. In FY 2015, the County transferred $326,567 to the GF.
- Library District - FY 2014, the County charged the District $245,564. In FY 2015, the County transferred $208,575 from the District to the GF.
- Public Health Services District - The County transferred $1,041,767 from the District to the GF, of which $461,467 was for reimbursement of indirect services and $580,300 was to offset state cost shifts (AHCCCS). In FY 2015, the County will transfer $408,222 for indirect services and $580,300 for state cost shifts (AHCCCS).
- HURF - The County transferred $726,763 from HURF to the County GF for reimbursement of indirect services. In FY 2015, the County charged $769,705 to HURF for reimbursement of services.
- State Budget Flex Language: The County is planning to transfer an additional $1.430 million from its special taxing districts at the end of FY 2015 if the PILT revenues are not realized. The transfers are planned as follows: Flood Control District ($650,000); Public Health Services District ($580,300); and Library ($200,000).

Expenditures

- Employee compensation: In FY 2014, the County gave employees a 2% salary adjustment, which was decided by the Board at its December 2013 meeting. The total impact was $250,000. In FY 2015, the County awarded all employees with a 2% COLA at a total cost of $454,173 ($244,757 to the GF/$209,416 to OF). An additional 2% one-time payment may be awarded at some point during FY 2015 if funds are available with the same total impact of $454,173 ($244,747 to GF/$209,416 to OF). In addition, the County awarded market adjustments to 52 of its Sheriffs, with increases ranging from 10% to 15%. The total impact is $316,053 ($294,576 to GF/$21,477 to OF).
- Budgeted payroll: The FY 2014 budgeted payroll in the GF, including EREs, decreased from $23,775,588 to $23,526,782. Total budgeted payroll dropped from $40,951,915 to $39,595,983. In FY 2015, the budgeted GF payroll increased $1,929,523 (8.2%) to $25,456,305. Total budgeted payroll increased $2,363,616 (6%) to $41,959,599.
- Budgeted FTEs: In FY 2014, budgeted FTEs in the GF increased from 346 to 376 (increase was the result of the GF absorbing Detention Officers due to the loss of the US Marshals contract). Total FTEs increased from 659 to 679. In FY 2015, GF FTEs increased 394 and total FTEs increased to 692.
- Health benefits: In FY 2014, the County's overall rates for health insurance were anticipated to increase by 6.5%; however, as a result of many employees converting to a high deductible health plan in lieu of their existing co-pay option, the cost to the County actually decreased by approximately $100,000. Depending on the Health Plan option, the employer/employee percentage contribution split for employee coverage can range between 90/10 to 95/5 and employee/family coverage can range between 80/20 to 85/15. In FY 2015, health insurance premium costs increased 9.7%, which was distributed proportionately between the County and employees. The total impact amounted to $236,825 ($147,891 to GF/$88,934 to OF.)
- Employee vacancy & turnover rates: In FY 2013, the County had an employee vacancy rate of approximately 10.6% and a turnover rate of approximately 20% for all funds.

Capital Projects

In FY 2015, the County's capital projects budget decreased from $10,060,926 to $6,500,000 and includes the following: Jail construction ($2 million); Regional Communications ($1.25 million); Public Works Complex-Holbrook ($3 million); and Health-Holbrook ($250,000).

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County held $17,150,000 in revenue bonds. In FY 2014, the County issued $10,625,000 in new revenue bonds to refund $4.8 million of its existing revenue bonds, $1.2 million for Detention Facility improvements, and $4.5 million for a new Public Works complex. As a result, the total revenue bond debt service payments decreased from $7.5 million to $3 million.

PIMA COUNTY

Overview

- Pima County's GF budget for FY 2015 is $521,401,927, an increase of $17,877,096 (3.6%) over last year's GF budget of $503,524,831.
- The County's unreserved GF balance for the beginning of this fiscal year is $32,474,480, $11,582,133 (26.3%) less than last year's budgeted fund balance of $44,056,613.
- Total financial resources available decreased $71,489,998 (4.6%), from $1,569,147,951 to $1,497,657,953. Total budgeted expenditures decreased $78,435,365 (6.2%), from $1,266,899,617 to $1,188,464,252. The large decrease in this year's total budget was mainly the result of the county excluding $84 million in the Regional Wastewater Reclamation Capital Improvement Program from the total budgeted expenditures. The total budgeted expenditures represent 79% of the total budgeted financial resources.

Property Values

- Pima County's primary NAV dropped 0.5% to $7,518,481,988. New construction amounted to $153,837,905 (2.05% of total NAV). The secondary NAV decreased 0.6% to $7,579,898,868.

Property Tax Revenues

Primary Levy

- The County increased its primary tax rate over 61 cents, from $3.6665 to $4.2779. This year's tax rate exceeded the TNT rate of $3.7633 by $0.5146. As a result, the primary tax rate is just $0.6941 below the maximum tax rate of $4.9720.
- The primary levy increased $44,477,673 (16%), from $277,155,468 to $321,633,141.

Debt Service

- The County's debt service tax rate dropped $0.0800, from $0.7800 to $0.7000. The levy decreased $6,405,500 (10.8%), from $59,464,792 to $53,059,292.
- The debt service budget is down $9,089,649 (7.3%), from $124,043,471 to $114,953,822.

Flood Control District

- The District's NAV dropped $998,769, from $6,768,456,641 to $6,767,457,872.
- The levy is up $2,591,862 (14%), from $17,834,883 to $20,539,235. The tax rate increased $0.0400, from $0.2635 to $0.3035.
- The District's budget is up $3,436,583 (27.5%), from $12,484,183 to $15,920,766 (excluding grants).
- The FY 2015 beginning fund balance was 7,390,056.

Library District

- The Pima County Library District tax rate is up $0.0600, from $0.3753 to $0.4353. The levy increased $4,259,836 (15%), from $28,487,320 to $32,747,156.
- The Library District budget is up $2,202,853 (6.3%), from $35,000,000 to $37,202,853 (excluding grants). The County operates 27 branches, a Book Mobile, and main deposit locations at the Pima County Jail and the Juvenile Detention Center.
- The FY 2015 beginning fund balance was 4,526,990.

PIMA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	3.6665	4.2779	0.6114	3.7633	$277,155,468	$321,633,141	$44,477,673	16%
Bonds	0.7800	0.7000	-0.0800		$59,464,792	$53,059,292	-$6,405,500	-11%
Flood Control	0.2635	0.3035	0.0400		$17,947,373	$20,539,235	$2,591,862	14%
Library	0.3753	0.4353	0.0600		$28,487,320	$32,747,156	$4,259,836	15%
OVERALL RATE	**5.0853**	**5.7167**	**0.6314**		**$383,054,953**	**$427,978,824**	**$44,923,871**	**12%**

Stadium District

- In FY 2015, the total budgeted revenue in the Stadium District is $2,656,135. The revenue in the Stadium District is generated from car and recreational vehicle space rental surcharges of $1,590,000, charges for services provided for special events of $1,045,000 (mostly from soccer events), and $21,135 from investment earnings.
- An additional $5,531,284 is transferred in from the County GF to the District as follows: $2,295,351 from the hotel/motel tax; $1,058,002 for maintenance of baseball practice fields; and $2,177,931 in additional GF support.
- The Stadium District budget increased from $5,039,746 to $5,253,097. There is a debt service payment of $2,855,700 included in the FY 2015 budget, which is the annual debt service for the COPs issued to pay for the construction of the stadium facilities. The COPs will be paid off in December 2017.

Other GF Revenues

- State shared sales tax revenues are budgeted to bring in $106,640,000, $7,340,000 (7.4%) more than last year.
- Auto in Lieu tax is up $768,000 (3.3%), from $23,332,000 to $24,100,000.
- Transient lodging tax is up $177,267 (3.2%), from $5,493,600 to $5,670,867.
- PILT is expected to generate $2,035,000 in FY 2015.

Other Special Revenues

Transportation

- Intergovernmental revenue (HURF) is budgeted to generate $49,323,707, $89,867 more than last year.
- The transportation budget decreased $1,095,454 (2.7%), from $40,277,267 to $39,181,813.

Sheriff

- The County charges $247.83 to jurisdictions for misdemeanor arrests for the first day and $80.10/day for the remaining time served. Total revenue budgeted for correctional housing is $7,626,700 in FY 2015. The adult facility can hold up to 2,377 beds and the estimated average occupancy is 88%.
- In FY 2015, budgeted expenditures in the Sheriff's office (GF and special revenue funds) increased $1,633,497 (1.1%), from $148,893,784 to $150,527,281.

Charges to Special Districts: In FY 2015, the County moved personnel costs that had been directly charged to departments into County administrative overhead, which was offset by corresponding reductions in personnel costs.

- Library District – The County charged the District $2,797,497 in FY 2014 for administrative overhead costs. In FY 2015, the County charged the district $4,032,733.
- Flood Control District – The County charges the Flood Control District for administrative overhead and a $1.60 per parcel fee for tax assessment and collections. In FY 2014, the County charged the District $1,296,362. In FY 2015, the County charged the district $1,612,597.
- Road Fund – In FY 2014, the charge to the Road Fund was $1,800,296. In FY 2015, the County charged the district $2,876,868.

Expenditures

- Employee compensation:
  - In FY 2014, all employees received a 1% COLA effective 7/1/13 and an additional 2% effective 1/1/14 at a total cost of $6,610,336 ($4,505,480 to the GF/$2,104,856 to OF). In addition, employees received a one-time lump sum compensation adjustment on July 19, 2013 based on length of time of service since the last compensation adjustment in FY 2008, which ranged from $200 to $1,000 per employee at an estimated total cost of $5,317,800 ($3,456,570 to the GF).

- In FY 2015, the County gave employees a $0.50/hour increase. The impact to the GF was estimated at $5,257,866 and $7,793,546 to TF (these costs were absorbed within the existing departmental budgets).

- Budgeted payroll: In FY 2014, the GF budgeted payroll, including EREs, was $295,845,411 and the amount budgeted for TF was $444,134,424. In FY 2015, the budgeted payroll in the GF is up $13,709,784 (4.6%) to $309,555,195 and TF are up $20,518,505 (4.6%) to $464,652,929.
- Health benefits: The County is self-funded and anticipates costs to increase approximately 5% in FY 2015.
- Budgeted FTEs: In FY 2014, GF FTEs increased from 4,731 to 4,739 and FTEs in TF increased from 7,314 to 7,328. In FY 2015, GF FTEs increased to 4,755 and TF FTEs dropped to 7,255.

Capital Projects

The total Capital Projects fund, which includes both bond and non-bond projects, is budgeted at $145,815,785 in FY 2015. The projects are broken down as follows:

- Transportation ($62,056,308): 49 projects.
- Facilities Management ($33,915,787): 18 projects including $30 million for the Downtown Court Complex project, $690,000 for the Roy Place Building Facade Restoration Completion, and $500,000 for the Legal Services Building Lighting Retrofit.
- Regional Flood Control ($15,138,247): 12 projects, including $4 million for the Santa Cruz River Flood Control Erosion Control & Linear Park, $2.4 million for the CDO Pathway, $2 million for the Urban Drainage project, $2 million for the El Corazon de los Tres Rios Del Norte project, $1.6 million for the TV Creek, and $1 million for the Floodprone Land Acquisition Program.
- Open Space ($10,404,623): $7.5 million for the Painted Hills property acquisition, $1.4 million for Town of Sahuarita priorities, $1.3 million for Tucson Mountain Park, and $100,000 for the Raytheon Buffer.
- Natural Resources, Parks and Recreation ($8,767,599): 11 projects including $4.1 million for the Northside Community Park, $1.2 million for the Pantano Path, $870,842 for the Southeast Community Park, $723,926 for the Santa Cruz River Park, $620,686 for the Catalina Community Park, and $579,000 for the Pantano Infill.
- Information Technology ($5,345,240): 8 projects, including $2 million for Data Center Storage Growth and $1.9 million for Public Works Permitting/Licensing Application.
- Sheriff ($4,561,707): $4.5 million for the Regional Public Safety Communications System.
- Community Development ($2,621,164): 5 projects, which includes a major project of $1.1 million for Housing Reinvestment 2004 Authorization.
- Finance ($1,000,000): AMS v.3.10 upgrade.
- Office of Sustainability and Conservation ($905,110): 7 projects total.
- Elections ($750,000): Election System upgrades.
- Environmental Quality ($350,000): Environmental Remediation/El Camino del Cerro Landfill.

Sources of Funding: Bond/COPs Proceeds ($78,681,000); Intergovernmental Revenue ($22,094,324); Operating Transfers ($41,312,487); Charges for Services/Impact Fees ($3,003,300); Investment & Miscellaneous Revenue ($724,674).

- Additional CIP projects for Telecommunications, Fleet Services, and Regional Wastewater Reclamation: $1.5 million for the VoIP Phone System; $6.8 million for Fleet Services ($5.2 million for the new Fleet Services Facility and $1.3 million for the Mission Road Complex Fuel Island); $84.3 million for 62 reclamation projects.

The County paid $8.75 million for the purchase of land to expand the soccer complex at the Kino Sports Complex (down payment of $1.75 million was paid from the GF and the remaining amount to be paid off over five years). Soccer fields will be constructed in a future fiscal year when funding becomes available. The cost to build the soccer fields are estimated to be between $25 million and $35 million. In addition, the County purchased land in the Painted Hills area for $7.5 million, $3.5 million of which came from the 2004 Open Space program. The remaining amount required from both projects will be included as part of the County's bond question on the FY 2015 ballot. If voters fail to approve the ballot measure, the GF will provide the necessary funding for the Kino Sports Complex debt and the Starr Pass Environmental Enhancement Fund for Painted Hills debt.

Prop 415

At the November 2014 election, voters approved $22 million in general obligation bonds to build a new Animal Control Center.

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, Pima County held $138,900,000 in COPs, $407,275,000 in GO bonds, and $778,750,019 in Revenue bonds. In addition, the Stadium District held $10,375,000 in lease-purchase debt and the County held $639,400 in lease-purchase debt.

GO Bond debt: The budgeted payment in FY 2015 is $53,120,800.

Street and Highway Revenue Debt Service: The 1997 Transportation Bond authorization provides for the sale of Street and Highway Revenue bonds with the debt service being repaid from HURF revenues. The budgeted debt service in FY 2015 is $18,881,569.

Certificates of Participation (COPs): The 2008 and 2009 COPs were issued primarily to fund short-term cash flow requirements affecting the construction of transportation and sewer projects. The debt service is primarily funded with operating transfers from transportation impact fees and sewer revenue funds. In January, 2010, the County issued $20 million in COPs to fund the PimaCore project for the acquisition of a countywide resource management system. In FY 2013, the County issued $54.5 million in COPs, in which $30 million funded short-term cash flow requirements, $18.5 million for the construction of Fleet services facility improvements, and $6 million for the construction of Curtis Park. The total debt service payment in FY 2015 is $40,075,738.

Additional Debt Service: The debt service for the Stadium District is $2,855,700, $2,134,085 for the Regional Wastewater Reclamation Enterprise Fund, and $69,750,706 for Sewer Revenue Bonds.

In FY 2015, the Citizen's Bond Committee is reviewing possible projects for inclusion in a bond election that will not occur until 2014 or 2015.

PINAL COUNTY

Overview

- Pinal County's GF budget for FY 2015 is $184,084,963. This is a decrease of $9,566,238 (4.9%) below the FY 2014 budget of $193,676,201. The decrease in the GF was mainly the result of a reduction in the County reserves ("designation for financial stability" line item) by $14.6 million.
- The County shows an unreserved GF balance of $40,392,961, which is $8,734,325 (17.8%) less than last year. The fund balance represents 22% of the GF budget.
- The total budget increased $4,355,538 (1.2%), from $373,723,558 to $378,079,096.

Property Values

- Primary NAV increased 0.8% to $2,005,151,766. New construction amounted to $35,575,419 (1.77% of total NAV). Secondary NAV increased 1.8% to $2,040,749,841.

Property Tax Revenues

Primary Levy

- The primary tax rate remains the same at $3.7999, which is $0.0372 less than the TNT rate of $3.8371.
- The primary property tax levy for FY 2015 is $76,193,762, generating $618,221 (0.8%) more revenue than last year's levy of $75,575,541.

Flood Control District

- The District's NAV increased $71,471,257 (4.3%), from $1,669,430,618 to $1,740,901,875.
- The levy increased $121,501 (4.3%), from $2,838,032 to $2,959,533. The tax rate for the District remained the same at $0.1700.
- The budget is down $1,414,927 (9.1%), from $15,465,579 to $14,050,652.
- In FY 2014, the fund balance in the district was $13.3 million. The FY 2015 beginning fund balance is $10,958,065.

Library District

- The Library District levy is $34,344 (1.8%) higher than last year at $1,979,527. The rate remained the same this year at $0.0970.
- The total Library District budget decreased $562,784 (24%), from $2,345,879 to $1,783,095.
- The FY 2014 fund balance in the Library District was approximately $1.8 million. The FY 2015 fund balance is approximately $500,000.

Public Health Services District

- The County BOS created the District by unanimous vote of the Board, which became effective in October 2007, and is funded by a 0.10-cent sales tax rate.
- The sales tax revenue that supports the District budget increased $223,356 (9%), from $2,492,130 to $2,715,486.
- The budget is up $623,366 (10.2%), from $6,135,086 to $6,758,452.
- In FY 2014, the fund balance was approximately $2.4 million. The FY 2015 beginning fund balance is $2,605,441.
- The MOE payment was $1,207,075 in FY 2014 and increased to $1,407,075 in FY 2015 (environmental health services added to the budget in FY 2015).
- The FY 2014 budget included a transfer of $361,888 from the District to the County GF for the debt service payment on its revenue bonds.

PINAL COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	3.7999	3.7999	0.0000	3.8371	$75,575,541	$76,193,792	$618,251	1%
Flood Control	0.1700	0.1700	0.0000		$2,838,032	$2,959,533	$121,501	4%
Library	0.0970	0.0970	0.0000		$1,945,183	$1,979,527	$34,344	2%
OVERALL RATE	**4.0669**	**4.0669**	**0.0000**		**$80,358,756**	**$81,132,852**	**$774,096**	**1%**

Other GF Revenues

- The half-cent sales tax increased $1,311,000 (10%), from $13,041,000 to $14,352,000.
- State shared sales tax is up $1,473,750 (5.1%), from $28,800,000 to $30,273,750.
- Auto in Lieu is up $512,500 (6%), from $8,500,000 to $9,012,500.
- PILT increased $127,757 (11.7%), from $1,087,865 to $1,215,622.
- Building permit revenues increased $217,037 (15%), from $1,446,912 to $1,663,949.
- The County received $550,000 in lottery funds in FY 2015.

Special Revenue Funds

Roads

- HURF revenue is up $1,867,958 (8.5%), from $22,000,000 to $23,867,958.
- The HURF budget is up $7,135,371 (29%), from $24,372,710 to $31,508,081.

Jail Facilities

- **Adult Jail**: The adult facility has a maximum of 1,511 beds with an average daily occupancy of 1,135. The County has a contract with the US Marshals to rent up to 250 beds at $59.74/day, and up until recently, ICE to rent up to 625 beds at $59.64/day. Consequently, the County's ICE contract was terminated on July 25, 2014, which previously generated approximately $11 million in revenue. As a result, probationary employees were terminated and vacancies were held open for position eliminations. A consultant study is currently underway to determine the most efficient and effective way to operate and staff going forward. Budgeted revenue from renting beds in the adult facility was $15,402,300 in FY 2014. In FY 2015, estimated revenues dropped to $13,874,500. Now as a result of the terminated contract, an initial budget reduction of $5 million was approved by the Board, with further reductions to be determined once the study is final.
- **Juvenile**: The juvenile facility holds 96 beds, with an average occupancy of 23. Up to 22 beds are rented to the US Marshals at $175/day (average beds rented to the US Marshals is 4).

Charges to Special Districts

- Flood Control District - In FY 2014, the County charged the District $50,000 for reimbursement of services. The FY 2015 budgeted transfer is $47,413.
- Library District - In FY 2014 and FY 2015, the County charged the District $650,000.
- Public Health Services District - In FY 2014, the County charged the District $406,003. In FY 2015, the County is not charging the District due to the District taking over environmental Health Services and transportation program as a result of the loss in grant funding.
- Road Fund – The County charged the Fund $1,751,594 in FY 2014 and FY 2015 for indirect costs.

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a 2.5% merit increase (effective Spring 2014). The annualized cost was approximately $2.4 million. In FY 2015, an equivalent increase of 2.5% has been set aside in the budget that may be awarded to employees in the fourth quarter if approved by the Board. County officials state that the Board's approval depends on the financial status of the County at that time and the outcome of a classification and compensation study that is currently being conducted. If implemented, the annualized total impact will be $2.8 million ($2.2 million to the GF). The County currently has a 14-step system but there is no guarantee that employees will automatically receive a step increase and the Board will decide if that is something they want to authorize in the future. After the study, the County may move away from the 14-step system.

- Budgeted payroll: In FY 2015, GF budgeted payroll, including EREs, increased from $111 million to $113.2 million. Total payroll is up from $146.7 million to $149.8 million.
- Health benefits: In FY 2013, the County covered a flat amount toward employee benefits at $6,741/employee. The County absorbed 100% of the increase in insurance premiums, which was estimated to be 10%. The budgeted cost of the increase to the County was $503,909 to the GF and $686,801 to all funds. The County did no budget for any cost increases in FY 2014. In FY 2015, the flat rate benefit for contribution is $7,709/employee. Increases due to ACA were passed on to employees in the form of increasing their contributions and other actuary increases were absorbed by the County. The Impact to the County GF was approximately $1 million and $1.5 million to TF.
- Budgeted FTEs: In FY 2015, GF FTEs increased 28 to 1,572 and total FTEs decreased 5 to 2,118.
- Employee vacancy & turnover rates: The County has a vacancy rate factor of approximately 7%. The County does not currently calculate a turnover rate.

Capital Projects

The total capital projects budget in FY 2015 is $20,282,039:

- Countywide Computer Project ($2,860,000)
- Public Works/Kelvin Bridge ($5,931,000)
- Public Works/Gantzel Road ($8,759,987)
- Fairgrounds ($154,552)
- Capital projects miscellaneous ($2,574,500)

The BOS will consider approval of the four additional projects at its November meeting: Hunt Hwy ($20 m), Ironwood Dr. imps ($5 m), upgrade of radio systems for Sheriff's office ($19 m), and master plan for courts construction & security ($15 M).

Debt

According to the Department of Revenue's FY 2014 Report of Bonded Indebtedness, the County held $54,620,000 in MPC debt and $78,960,000 in revenue bonds. In addition, the County held $566,443 in lease-purchase debt.

In FY 2011, the County issued $30.4 million in new revenue bonds, of which $12 million was for construction of health clinics and renovations of human resources and administration office space. Over $18 million was for the refunding of the Series 2001 COPs.

At its November meeting, the BOS will consider the refinancing of approximately $41 million of the 2006 GADA loan and approximately $45 million of the 2004 COPS that was issued for the adult detention facility and other projects. The financing will be secured with excise tax revenue and may occur in the spring of 2015.

Debt Service Payments: Total debt service payments in FY 2015 amount to a total of $15,683,726 and include the following:

- Adult/juvenile detention expansion COP ($4,970,425); Series 2010 refunding bond ($2,500,900); capital leases ($89,019).
- GADA loan: Ironwood/Gantzel Road ($5,121,175); Animal Control expansion ($213,085); 2008 long-term care facility ($347,665); and various projects ($1,581,238).
- Series 2010 bonds/public health clinic and GF ($770,076).
- Lease & Long-Term Debt: Heavy equipment leases ($90,143).

SANTA CRUZ COUNTY

Overview

- Santa Cruz County's FY 2015 GF budget is $28,661,791, which is $1,157,342 (4.2%) higher than last year's budget of $27,504,449.
- The County started the year with an unreserved GF balance of $10,336,084. This is $613,607 (5.6%) below last year's balance of $10,949,691. The fund balance represents 35.6% of the total GF budget.
- This year's total budget of $74,308,956 is $3,953,722 (5.6%) more than last year's adopted budget of $70,355,234.

Property Values

- The primary NAV decreased 5.1% to $320,999,663. New construction amounted to $3,574,722 (1.11% of total NAV). The secondary NAV dropped 4.7% to $323,843,644.

Property Tax Revenues

Primary Levy

- The primary property tax rate of $3.6471 that was adopted by Santa Cruz County is the county's TNT rate, which is up $0.2256 from last year's adopted rate of $3.4215.
- The adopted primary property tax levy of $11,707,247 is $130,374 (1.1%) higher than last year's levy of $11,576,873.

Flood Control District

- The District's NAV decreased $17,202,133 (5.5%), from $311,805,366 to $294,603,233.
- The levy is up $15,152 this year, from $2,133,684 to $2,148,836. The rate increased $0.0451, from $0.6843 to $0.7294.
- The budget is down $539,326 (7.2%), from $7,454,383 to $6,915,057, of which $4,153,207 is dedicated as reserves.

SANTA CRUZ COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	3.4215	3.6471	0.2256	3.6471	$11,576,873	$11,707,247	$130,374	1%
Flood Control	0.6843	0.7294	0.0451		$2,133,684	$2,148,836	$15,152	1%
OVERALL RATE	**4.1058**	**4.3765**	**0.2707**		**$13,710,557**	**$13,856,083**	**$145,526**	**1%**

Other GF Revenues

- Auto in Lieu tax revenues are up $100,000 (7.7%), from $1,300,000 to $1,400,000.
- The half-cent sales tax is up $300,000 (13%), from $2,300,000 to $2,600,000.
- State shared sales tax is up $600,000 (15.4%), from $3,900,000 to $4,500,000.
- PILT stayed the same at $900,000.
- The County budget includes $550,000 in state Lottery revenues.

Special Revenue Funds

- Road fund revenue is up $231,000 (5.6%), from $4,119,000 to $4,350,000.
- Forest fees decreased $75,000 (13%), from $575,000 to $500,000.
- The Road Fund budget increased $300,804 (5%), from $5,966,584 to $6,267,388.

Jail District

- Voters approved the Jail District in November 2005, with the ability to levy a half-cent sales tax effective 7/1/06. In FY 2015, total revenues in the District decreased $1,497,891 (30%), from $5,000,000 to $3,502,109, which includes a combination of the ½-cent sales tax revenue and revenue from renting beds to other entities.

- **Adult facilities:** The adult jail facility holds 377 beds and the average occupancy is approximately 35%.
- The Jail District budget is down $2,087,510 (23%), from $9,081,023 to $6,993,513. The FTEs in the District dropped from 85 to 77. Total personnel compensation costs FTEs in the District, with total personnel compensation costs, including EREs, dropped from $4,043,644 to $2,617,876 (salaries from $2.8 million to $1.8 million). [Changes made to the personnel costs in the Jail District at final budget adoption are not reflected in Schedule G of the budget per County officials.]
- In FY 2015, medical expenses in the jail facilities are down from $900,000 to $400,000 as a result of the reduction in the jail population. The County now has three nurses (down from four) assigned to the jail facilities.
- In FY 2014, the District anticipated renting approximately 140 beds on average to other entities, such as the US Marshals, ICE, and Customs, at a charge of $65/day. The Feds are responsible for any additional medical and dental costs, as well as transportation costs. In FY 2014, approximately $2 million was estimated in revenue for the housing of inmates for other jurisdictions, which is down from the previous year's revenue estimate of $3 million. In FY 2015, the estimated revenue for renting beds to Federal prisoners plummeted to $700,000. Like other Arizona counties, Santa Cruz County is experiencing a dramatic decline in the housing of federal inmates.
- The MOE payment increased from $3,015,761 to $3,076,077.
- **Juvenile jail facility:** The juvenile facility was completed in 2010 and holds 32 beds. The current occupancy levels are low.

Charges to Special Districts:

- Flood Control District - The County charged the District $108,066 in FY 2014 and FY 2015.
- Road Fund - The amount charged to the Road Fund in FY 2014 and FY 2015 was $279,019.

Expenditures

- Employee compensation: In FY 2014, the County awarded employees with a one-time bonus of $1,000 for full-time employees and $500 for part-time permanent employees, effective December 2014. The total impact was $205,000 ($160,000 to the GF). In FY 2015, the County budgeted for a 5% across the Board raise for all permanent employees, which was awarded in October 2014. The estimated total impact was $785,000 ($359,000 to the GF).
- Budgeted payroll**:** In FY 2015, GF budgeted payroll, including EREs, increased from $11,695,322 to $11,817,048. Total budgeted payroll decreased from $23,586,796 to $23,353,224.
- Health benefits**:** Health premiums did not increase in FY 2013. The average subsidy for employee coverage is 89.3% and 75.3% for dependents. In FY 2014, the County absorbed the increase in health insurance costs at a total cost of approximately $106,000 ($48,000 to the GF and $58,000 to other funds). In FY 2015, health premiums increased 4.3%, which was entirely absorbed by the County. The net impact between the GF and other funds was $88,278.
- Budgeted FTEs**:** In FY 2015, budgeted GF FTEs increased from 180 to 183 and total FTEs decreased from 386 to 378.
- Employee vacancy & turnover rates: The County employee vacancy rate is less than 5% and the estimated employee turnover rate is less than 1%.

Debt

At the end of FY 2014, Santa Cruz County held $13,585,000 in outstanding revenue bonds, which was a GADA loan used for the new court facilities (the debt is scheduled to be paid off in 2032). The debt service payment in FY 2015 is budgeted at $1,094,515 (actual payment is $994,925). The County also held $9,351,453 in lease-purchase debt.

The Santa Cruz County Jail District had $36,665,000 outstanding in revenue bonds at the end of FY 2014 and the budgeted debt service payment in FY 2015 is $3,246,506. The debt in the Jail District is scheduled to be paid off in 2031.

Flood Control District-revenue debt

In January 2012, the BOS approved a $13 million, 20-year loan for the construction of the Chula Vista Bridge and Palo Parado Road. The $13 million obligation is the result of an IGA between the County BOS and the Flood Control District, in which the BOS is the Board of Directors. The annual debt service payment amounted to $688,172 in FY 2015.

Construction on the Palo Parado project was completed in March 2013. Construction on the Chula Vista Bridge will be completed during the Fall of 2014 and the County received the necessary funding from the federal government. Based on previous estimates, the total cost of the Chula Vista project was $56 million and the County impact amounted to approximately $2 million.

Capital Projects

The capital projects budget increased from $796,602 to $2,621,661, which includes the following projects: Apron Construction ($1,770,258); Phase I Apron design ($100,000); Environmental assessment ($203,000); Courthouse construction ($16,249); Jail District Construction ($92,179); Rio Rico Rd. improvement CDBG ($380,341); CDBG projects ($59,634).

YAVAPAI COUNTY

Overview

- The County GF budget for FY 2015 of $94,937,304 is a $5,257,600 (5.9%) increase over last year's adopted budget of $89,679,704.
- This year's beginning GF balance of $6,523,933 is $1,255,932 (23.8%) more than last year's balance of $5,268,001. The fund balance represents 6.9% of the total GF.
- The total financial resources in FY 2015 increased $7,410,729 (3.3%), from $224,231,808 to $231,642,537. The total budgeted expenditures in FY 2015 amount to $199,955,116 and represent 86% of total financial resources.

Property Values

- The primary NAV decreased 0.7% to $2,217,272,811. New construction amounted to $32,593,402 (1.47% of total NAV). The County's secondary NAV dropped 0.5% to $2,267,389,484.

Property Tax Revenues

Primary Levy

- This County's primary property tax levy of $43,415,263 is the same levy as last year plus an additional $306,703 for a property tax judgment.
- The primary rate increased $0.0272, from $1.9308 to $1.9580, which is below the County's TNT rate of $1.9732.

Flood Control District

- The District's NAV increased $41,128,020 (2.2%), from $1,893,026,850 to $1,934,154,870.
- The tax rate decreased from $0.2162 to $0.2116. The levy stayed the same at $4,092,000.
- The budget decreased $749,012 (8.9%), from $8,395,225 to $7,649,213.
- In FY 2014, the beginning fund balance was 4,103,225. In FY 2015, the beginning fund balance is $3,357,213.

Library District

- The Library District rate increased from $0.1491 to $0.1512. An additional $27,977 was levied for the property tax judgment, thereby increasing the levy from $3,400,000 to $3,427,977.
- The Library District budget decreased $482,896 (10%), from $4,827,414 to $4,344,518.
- In FY 2014, the beginning fund balance was $1,361,271. In FY 2015, the beginning fund balance is $878,375.
- County employees only staff libraries in unincorporated areas of the County. Otherwise, cities administer their municipal libraries and receive a direct contribution of cash for their operations. The County supports all libraries with the library network for inter-library book loans, databases, and capital improvements.

YAVAPAI COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	1.9308	1.9580	0.0272	1.9732	$43,108,560	$43,415,263	$306,703	1%
Flood Control	0.2162	0.2116	-0.0046		$4,092,000	$4,092,000	$0	0%
Library	0.1491	0.1512	0.0021		$3,400,000	$3,427,977	$27,977	1%
OVERALL RATE	**2.2961**	**2.3208**	**0.0247**		**$50,600,560**	**$50,935,240**	**$334,680**	**1%**

Other GF Revenues

- The County apportions the ½-cent sales tax as follows: 45% to the GF, regional roads 40%, and 15% for capital improvements. The total budgeted ½-cent sales tax for FY 2015 is $15,150,875, which is $904,704 (6.4%) more than last year's budgeted revenues of $14,246,171.
- VLT increased $462,357 (6.8%), from $6,812,796 to $7,275,153.
- State shared sales tax is up $1,808,962 (7.3%), from $24,741,824 to $26,550,786.
- PILT revenues decreased $214,027 (8.1%), from $2,642,970 to $2,428,943.

- The County received $550,038 in Lottery revenues.

Special Revenue Funds

Road Fund

- In FY 2015, total revenues in the Public Works funds are up $3,047,710 (20.7%), from $14,706,256 to $17,753,966. The available fund balance is $16,638,728.
- The Public Works budget increased $3,738,053 (15.5%), from $24,055,810 to $27,793,863.

Jail District

- Yavapai County voters approved the Jail District in November 1999 with the authority to levy a ¼-cent sales tax to fund the District. At the November 2014 ballot, the County asked voters to increase the ¼-cent sales tax to ½-cent for an additional 20 years; however, the measure failed to pass. According to County officials, the purpose of the increased sales tax was to fund a jail in Prescott to house up to 300 beds with the capability to expand since the existing jail, which is in Camp Verde, is at its maximum occupancy. The estimated cost to build the new jail was approximately $26 million.
- In FY 2015, the sales tax will generate $7,574,902, $452,650 (6%) more than last year.
- There are approximately 600 beds in the Verde Valley adult facility, with the ability to open an additional 44 beds (the Prescott facility held 135 beds). The average occupancy of the Verde Valley facility was 533 in FY 2014. In FY 2015, the County estimated total revenues from renting beds dropped from $1,770,000 to $1,200,000 due to the decrease in U.S. Marshals prisoners. The County also rents beds to the state Department of Corrections and the tribes.
- In FY 2015, the MOE payment increased $193,133 (2.8%), from $6,836,804 to $7,029,937.
- The Jail District budget increased $580,474 (3.6%), from $16,174,634 to $16,755,108. The fund balance in the District is $1,554,291.
- In FY 2015, medical costs in the jail are budgeted at $3,172,771, plus $312,499 in contingency. The County contracts with Wexford to deliver its medical services in the jails, including restoration-to-competency (RTC) services.
- The juvenile jail facility was built during FY 2013. The facility holds 80 beds and the average occupancy is approximately 50%.

Charges to Special Districts

- Flood Control District - In FY 2014, the County charged the District $550,000 for administrative costs. In FY 2015, the County charged the District $590,000.
- Library District - In FY 2014, the County charged the District $570,340 for administrative costs. In FY 2015, the County charged the District $650,340.

Expenditures

- Employee compensation: The County did not award pay raises to employees in FY 2014. In FY 2015, the County budgeted $2,550,411 in employee pay raises: a 1% COLA , with a total impact of $960,000 ($496,968 to the GF); up to 3% for "salary compression" raises to make up for the lack of pay raises over the last several years at a total impact of $1,590,411 ($837,679 to the GF).
- Budgeted payroll: In FY 2015, the GF budgeted payroll, including EREs, increased from $56,662,616 to $59,471,232. Total budgeted payroll increased from $96,204,074 to $101,623,615.
- Health benefits: In FY 2015, the 1.5% increase in health premium insurance costs were proportionally absorbed between the County and the employees. The total impact of the insurance premium increase was $605,907 ($282,281 estimated impact to the GF). The County continues to pay 100% of employee benefit costs and 25% for dependents.
- Budgeted FTEs: The budgeted GF FTEs in FY 2015 increased from 850 to 874. The total budgeted FTEs increased from 1,504 to 1,555.

- Employee vacancy & turnover rates: The turnover rate for calendar year 2013 was 15.3%. The County removed its hiring freeze and all unbudgeted positions as a result.

Capital Projects

In FY 2015, the County's capital projects include the following, which will be funded with cash:

- Public Works addition ($2,026,446)
- Phase III of Courthouse renovations ($2,420,000)
- Marina Street renovations ($2,000,000)
- Adult Probation building-Verde Valley complex ($2,000,000)
- Health Department Facility ($2,000,000)

Debt

According to DOR FY 2014 Report of Bonded Indebtedness, the County held $21,830,105 in lease-purchase debt. This debt is the result of a 20-year, $25 million agreement in 2008 that was used to fund the Superior Court building next to the Camp Verde Jail ($11 million) and the Juvenile Detention and Administration facility on the Prescott Lakes Parkway ($14 million). This debt agreement requires annual principal and interest payments of $2,111,865 through FY 2028.

YUMA COUNTY

Overview

- Yuma County's FY 2015 GF budget decreased $1,966,018 (2.5%), from $77,258,446 to $75,292,428, which was mainly the result of a $2 million reduction in County reserves.
- The County started FY 2015 with an unreserved GF balance of $13,777,216, which is $2,799,645 (16.9%) less than last year's fund balance of $16,576,861. The fund balance represents 18.3% of the GF Budget.
- The FY 2015 total budget decreased $7,405,442 (3%), from $249,718,511 to $242,313,069.

Property Values

- The primary NAV remained nearly flat this year at $1,112,447,688. New construction amounted to $51,929,659 (4.67% of total NAV). The secondary NAV increased 0.7% to $1,139,598,176.

Property Tax Revenues

Primary Levy

- The County adopted a primary levy of $24,037,770, which is an increase of $1,121,520 (4.9%) above last year's levy of $22,916,250.
- The primary tax rate of $2.1608 is $0.1002 over last year's primary tax rate but is just below the County's TNT rate of $2.1609.

Flood Control District

- The NAV in the District dropped $31,251,711 (3.3%), from $958,740,667 to $927,488,956.
- In FY 2015, the levy decreased $91,264 (3.4%), from $2,682,668 to $2,591,404.
- The secondary tax rate for the District remained the same at $0.2794.
- In FY 2015, the District began the year with a fund balance of approximately $16.6 million. The fund balance has been accumulated for several projects, including the Smucker Park Detention Basin, in which the total estimated cost of the project is approximately $8.7 million. Last year, the District completed the design-phase of the project and is expected to be completed during FY 2015 at the latest.
- In FY 2015, the budget decreased $806,397 (3.9%), from $20,929,161 to $20,122,764.

Library District

- In 2005, the voters of Yuma County authorized the Library District to sell $53 million in GO bonds to pay for three new libraries, expansion/renovation of three branches, and enhancements of two branches throughout the County.
- The Library District levy increased $25,556, from $9,566,146 to $9,591,702 (M&O from $6,226,171 to $6,248,177; bonds from $3,339,975 to $3,343,525).
- The tax rate decreased slightly from $0.8424 to $0.8417 (M&O rate stayed constant at $0.5483; bond rate decreased from $0.2941 to $0.2934).
- The budgeted amount for debt service in FY 2015 is $7,346,862 (budgeted payment is $3,343,525 and the remainder is contingency).
- The beginning fund balance for FY 2014 was $8,319,022 and dropped down to $7.1 million in FY 2015.
- The Library District budget decreased $1,248,734 (8.6%), from $14,558,700 to $13,309,966.

YUMA COUNTY	FY 2014 RATE	FY 2015 RATE	CHANGE	TNT	FY 2014 LEVY	FY 2015 LEVY	CHANGE	% CHANGE
Primary	2.0606	2.1608	0.1002	2.1609	$22,916,250	$24,037,770	$1,121,520	5%
Flood Control	0.2794	0.2794	0.0000		$2,682,668	$2,591,404	-$91,264	-3%
Library*	0.8424	0.8417	-0.0007		$9,566,146	$9,591,702	$25,556	0%
OVERALL RATE	**3.1824**	**3.2819**	**0.0995**		**$35,165,064**	**$36,220,876**	**$1,055,812**	**3%**

*Yuma's Library District rate includes a rate of $0.2941 for voter-approved GO bonds in tax year 2013 and $0.2934 in tax year 2014.

Other GF Revenue

- Auto in Lieu is up $59,922 (0.9%), from $6,445,785 to $6,505,707, and is distributed as follows: $4,605,707 (GF); $950,000 (HURF-Public Works); and $950,000 (HURF-Development Services).

- The budgeted half-cent County sales tax is down $355,798 (2.9%), from $12,150,578 to $11,794,780.
- State shared sales tax increased $728,959 (4%), from $18,434,421 to $19,163,380.
- PILT is up $85,865 (2.7%), from $3,159,077 to $3,244,942.
- The County continues to receive $550,038 in state lottery revenues.

Special Revenue Funds

HURF (Road) Fund

- The County's HURF revenues are up $621,123 (6.8%), from $9,153,000 to $9,774,123. In addition to the Auto in Lieu revenues noted above, the County distributed $3,396,807 of HURF revenues to Development Services and $6,377,316 to Public Works in FY 2015.
- The HURF fund budget increased $581,506 (2.1%), from $28,024,847 to $28,606,353 ($18,438,024 in the Development Services fund and $10,168,329 in Public Works).

Jail District

- In FY 2015, the Yuma County Jail District sales tax decreased $355,798 (2.9%), from $12,150,578 to $11,794,780. In May 2011, voters approved a 20-year extension for the Jail District sales tax. The tax, which was originally scheduled to expire at the end of 2015, will now expire in 2035.
- The adult facility holds 757 beds and the average occupancy is 550. The County rents beds at $78/day for total budgeted revenues of $553,500 from the Cocopah Tribe and other entities ($43,500), the US Marshals, and other federal law enforcement agencies ($510,000). Medical expenses were budgeted at $725,000 in FY 2014 and remain the same for FY 2015.
- The juvenile facility holds 79 beds, which are rented to La Paz County and the Cocopah Tribe at an estimated $45,000 in FY 2014 and increased to $84,885 in FY 2015.
- There are 273 FTEs in the adult facility (includes 37 vacant positions) and 62 in the juvenile facility (includes 4 vacant positions).
- The County jail holds up to 757 beds, of which approximately 550 are occupied on average.
- In FY 2014, the beginning fund balance was approximately $2.8 million. The beginning fund balance in FY 2015 dropped to $308,593.
- The Jail District budget decreased $2,072,732 (10%), from $20,477,864 to $18,405,132.
- The MOE payment in FY 2015 is $6,613,040.

Public Health Services District

- The County BOS created the District in April 2005, which is funded with a local sales tax. On June 17, 2013, the Board voted to increase the sales tax rate from 0.10% to 0.112%, effective October 1, 2013. The sales tax is estimated to produce $2,630,236 in FY 2015, down $18,590 (0.7%) from last year.
- The MOE payment for the District is $786,898.
- The beginning fund balance in FY 2014 was $258,368 and increased to $895,422 in FY 2015.
- The budget increased $628,545 (14.4%), from $4,376,394 to $5,004,939.

Charges to Special Districts

- Flood Control District - The County charges the District a $2.00 per parcel fee for reimbursement of services. In FY 2014, the County charged the district $316,000 and budgeted for a charge of $177,100 in FY 2015.
- Jail District - The District was charged $573,802 by the County for reimbursement of services in FY 2014 and has budgeted to charge the district $424,665 in FY 2015.
- Public Health Services District - The County charged the District $465,524 for reimbursement of services in FY 2014. In FY 2015, the charge increased to $687,545.
- Library District - The County charged the District $331,955 for reimbursement of services in FY 2014, which dropped down to $294,580 this year.

Expenditures

- Employee compensation: In FY 2014, the County provided employees that met certain standards a step increase based on the following: 2 years < 5 years of service-1/2-step (2.5%); 5+ years of service-1 step (5%). The step increases were effective 9/2013, with a total annualized impact of $2 million ($1.1 million to the GF). [This information is based on the County Regular Step Pay Plan. The information varies for the other pay plans.]. The FY 2015 budget does not include any adjustments to employee compensation. Reclassifications: The County budgeted for twelve reclassifications in the FY 2015 budget, effective for July 1, 2014. The impact to GF budget is $27,114 and $55,570 to TF.
- Budgeted payroll: The GF budgeted payroll in FY 2015 increased from $43,938,932 to $44,575,773. The total budgeted payroll increased from $91,339,500 to $91,882,644.
- Health benefits: In FY 2014, the County increased their $250 deductible plan to a $500 deductible PPO option and reduced three plan options to one PPO and a high deductible health savings account and the County pays a percentage of the monthly premium costs. In FY 2015, the Employee Benefit Trust Fund budget increased $813,469 (4.4%), from $18,484,061 to $19,297,530. The only change in the benefit structure pertains to dependent coverage, which was changed from a 90/10 split to 80/20 split.
- Budgeted FTEs: In FY 2014, the GF FTEs were budgeted at 666 and total budgeted FTEs amounted to 1,445. In FY 2015, GF FTEs decreased to 659 and total budgeted FTEs decreased to 1,443.
- Vacancy & turnover rates: The current employee vacancy rate is approximately 7% and the turnover rate is under 1%.
- Restoration to Competency (RTC): In an effort to decrease expenditures attributable to RTC costs, the County developed its own program in FY 2014, which is modeled after the Yavapai County model that uses private providers. There are currently between seven to eight individuals funded in the program, down from ten last year.

Capital Projects

- The Capital Projects budget decreased $3,081,408 (31.6%), from $9,745,590 to $6,664,182. Capital projects slated for FY 2015 include:
  - County administration: Includes the renovation of the vacant building at 197 Main St. containing approximately 50,000 square feet. Initially, the County plans to occupy approximately 20,000 square feet with the ability to expand to full capacity. The County pledged its sales taxes to pay the debt service on the lease-purchase. The amount budgeted for the project this year is $4,484,751.
  - The remaining capital projects are included for various improvement districts ($1,129,736); Library District ($205,678); Administration-Port of Entry ($153,000); Jail District ($40,000); and general capital improvement projects ($651,017).

Debt

In FY 2013, the County entered into a lease-purchase agreement to construct the East County facility. In FY 2014, the County refunded the outstanding revenue bonds and combined that debt with $5.3 million in new debt, and increased the payoff of the debt from 10 to 20 years. According to the DOR FY 2013-14 Report of Bonded Indebtedness, the total outstanding lease purchase debt was $7,216,000. The budgeted debt service in FY 2015 is $502,450.

Library District: As of June 30, 2014, the total GO debt for the Library District was $44,310,000. Although the debt service payment in FY 2015 is reported as $7,346,862, the actual debt service payment is $3,343,525. The debt is scheduled to be paid off in FY 2035.

Jail District: The outstanding debt as of June 30, 2014 in the District was reported at $6,020,000 and the budgeted debt service payment in FY 2015 was $1,038,752. The debt will be paid off in FY 2021.

ATTACHMENT E

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RUCO 1.06

Gila River Fuel Cost and Revenue – On page 6 of the rate case Application, followed by a table on page 7, the Company states that rate payers would receive a reduction of $9.3 million or a decrease of 3.57 percent in year 1. Please provide the percentage increase per year if one were to average the $9.3 million over a three year period (i.e. $3.1 million per year). In addition, please provide the worksheet calculation.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Attached files RUCO 1.06_9.3M over _3 Years CAJ-2.xlsx and RUCO 1.06_9.3M over_3 Years Bill Impact Summary CAJ-2.xlsx provide the results of averaging the $9.3 million in cost over a three year period.

The Excel file is not identified by Bates numbers.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RUCO 1.08

Purchased Power and Fuel Adjustment Clause ("PPFAC") – On page 9, of the Company's Application the Company stated "Presently, the PPFAC rate is adjusted monthly and charged to customers on a per kWh basis. The modified PPFAC will still be adjusted monthly but the adjustment will be based on a percentage change calculation. This approach will better align the changes in fuel costs with each rate classes' base." Based on this statement and the example described on page 74 of Mr. Craig A. Jones testimony, is it fair to say the following:

a. Instead of assigning a partial percentage to each customer class based on a kilowatt per hour basis, the Company essentially wants the overall change in Kilowatt hours to be divided equally and allocated to each customer class. So there is no confusion hypothetically, if there are four customer classes with the following percentage decreases – Residential 30, Small General Services 30, Large General Service 20, and Large Light and Power 20. Under the Company's new proposal, each class of customer would be allocated a 25 decrease.

b. If the answer to subpart a. is correct, then please explain why this is not cross-subsidization?

c. Please explain why customer classes no longer have to pay their fair share?

RESPONSE:

a.-c. The hypothetical, as UNS Electric understands it, could not occur under either the current method or the proposed method. Under the current PPFAC method, in any given month the PPFAC kWh rate is the same for all rate classes. However, the Base Power kWh charge, as established in the Company's most recent rate case based on actual cost differences to serve each class.. That Base Power rate typically declines as the size of the class gets larger, reflecting the higher load factors and voltage differentials. Under current tariffs the Base Power rate for the Residential, Small General Service, Large General Service and Large Power Service rates are $0.064510, $0.058241, $0.056603 and $0.041880 per kWh, respectively. For purposes of this example, if one were to assume total system sales of 1.6 GWh, total fuel costs of $77 million and a change in fuel costs of $770,000, the current method would generally divide $770,000 by the sales of 1.6 GWh and calculate a PPFAC rate of approximately $0.000481 per kWh, and this would apply to all classes equally based on consumed kWh.

Using the above Base Power rates and PPFAC rate of $0.000481, the respective percentage change to each class' fuel cost would be: 0.75%, 0.83%, 0.85% and 1.15% ($0.000481 divided by the respective Base Power cost). Under the Company's proposed percentage based PPFAC method, the PPFAC rate would be 1.00% ($770,000 of fuel cost change divided by $77 million of Base Power cost). This percentage would be applied to each rate class equally. Thereby distributing the change in overall system purchased power and fuel cost equally based on the level of Base Power approved in the most recent rate case. In the Company's opinion this better aligns changes in fuel costs with each rate classes Commission approved Base Power costs.

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

Arizona Corporation Commission ("Commission")	UniSource Energy Services ("UES")
Fortis Inc. ("Fortis")	UniSource Energy Development Company ("UED")
Tucson Electric Power Company ("TEP")	UNS Electric, Inc. ("UNS Electric" or the "Company")
UNS Energy Corporation ("UNS")	UNS Gas, Inc. ("UNS Gas")

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 7, 2015

RUCO 1.16

Weather Normalization – What are the results (i.e. revenue adjustment in dollar terms) if the Company used its old weather normalization model which it used in its last rate case. Please provide your calculations and Excel worksheets.

RESPONSE:

The Company's updated weather normalization model matches the improved weather normalization model that the Company has developed since the last rate case. The new model has proven to be more statistically robust, as well as better at providing weather variance guidance with more consistent results.

The benefits of the new model are as follows:

1. It utilizes more accurate and objective measures of temperature.

   The old model took the daily high and low temperature in each day of the month to produce two daily degree day values (cooling degree days and heating degree days), each of which were then summed to produce two monthly degree day variables. The degree day variables assume a comfort level as experienced by the customer, namely 65 degrees, and insists that this comfort level is the same year-round and for all customer classes.

   The new model averages the temperature from each hour in the month and averages the dew point from each hour in the month. This level of detail is easy to capture now that we have desktop computers and data storage is not as expensive as it was, say, 50 years ago. The new model makes no attempts to define a comfort level for the customer. It merely looks at historical average temperatures and average dew points and compares it to historical usage per customer values. As such, the data can speak for itself and customers comfort levels can adapt throughout the year as outdoor temperatures change.

2. The new model is simpler and does better statistically when compared to the old model.

   The relationship between customer usage and average monthly temperature is not linear. A downfall of using cooling degree days and heating degree days is that such models attempt to model the relationship between customer usage and temperature in a linear manner. To get around this, in the old rate case, the Company used a cooling degree day variable and a heating degree day variable for each month called a seasonal dummy model. So, a cooling degree day variable for January would have the appropriate cooling degree day value for each January in the data history and a value of 0 for every other month in the data history. This leads to 12 cooling degree day variables and 12 heating degree day variables in the initial model (this might be reduced if the model produces a coefficient of 0 for any of these variables). As opposed to the new model which has one average temperature variable and one average dew point variable. Since these measures of weather do not force a linear relationship, we don't need to inflate the number of variables that we have. Even when accounting for the economic trend variable, the moving average variable, and the autoregressive variable that the new model has, which are not in the old model, this is fewer variables. Fewer variables are desirable in a statistical model when the model comparison statistics between two models are similar. The new model is not only simpler, but it has better model comparison statistics, such as R^2 and MAPE, which make it the statistically better choice.

3. The new model attempts to isolate weather effects from economical trend effects and non-weather related seasonal effects.

In the old model, the only input variables were the monthly degree day variables. In the new model, the Company includes additional variables to better capture what variances are due to weather and what variances are due to other factors. An economic trend variable has been added. The forecasts for the economic trend variables are taken from IHS.

The adoption of the use of the ARIMAX model allows the Company to account for seasonal trends that are not weather related, such as the coming and going of snow birds or students. The ARIMAX model does this largely by introducing autoregressive terms and moving average terms. The terms look for seasonal patterns in the data and attempts to capture these. The inclusion of these terms, along with the economic trend term, allow us to better estimate how much of a month's variance are due to weather as opposed to another external factor.

For these reasons, the Company found it advantageous to switch to the new model for weather normalization. Given the sophistication of the new model, it is to be expected that the results will differ slightly from the old method. Since it seems counter-productive to continue using outdated and statistically weaker models, the Company used this new model in the current rate case. For these reasons, the Company did not produce a revenue model based on the old weather normalization method.

To answer this question, the Company ran the old model to obtain the needed coefficients to produce weather normalized sales adjustments. These coefficients have been run through the sales adjustments files to produce what the adjusted sales would be based on the old method. It is a time consuming process to run these numbers through the bill frequency process and through the revenue model process, and as such, the Company has estimated what the effect of the old weather normalization model would have been on sales.

The table below contains the adjusted sales for the residential and commercial rate classes, the adjusted revenue for the respective classes based on the revenue proof for the current weather normalization method, and an estimate of revenue based on the old weather normalization method. The industrial, mining, and other rate classes are not weather normalized and therefore were not included in the table.

Adjusted Sales	Current Model (A)	Old Model (B)	Difference (A-B)	Adjusted Revenue	Current Model (C)	Old Model Estimate (C/A*B)=D	Difference (C-D)
Residential	823,953,185	839,151,190	(15,198,005)	**Residential**	$88,446,210	$90,077,621	($1,631,411)
Commercial	607,753,087	611,522,502	(3,769,415)	**Commercial**	$61,940,344	$62,324,511	($384,167)
Residential + Commercial	**1,431,706,272**	**1,450,673,692**	**(18,967,420)**	**Residential + Commercial**	**$150,386,554**	**$152,402,131**	**($2,015,578)**

The total adjusted test year revenue was $164,220,093, and thus the result with the old weather normalization method would be estimated to be around $166,235,671. The adjusted revenue numbers come from the "TY Revenue Proof" tab in 2015 UNSE Revenue Proof - Public Version.xlsx. The revenue numbers in this tab do not contain any pro forma adjustments to fuel. (The referenced file can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Schedule G and H Support.)

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 17, 2015

RUCO 2.03

Employee Benefits – Please provide the total costs spent on the Wellness Incentive program for the test year. In addition, is the Company seeking recovery of these costs in the current rate case?

RESPONSE:

Total costs spent on the Wellness Incentive program for the test year (2014) was $15,738.

Yes, the Company is seeking recovery of these costs in the current rate case.

RESPONDENT:

Steve Bracamonte

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
August 17, 2015

RUCO 2.04

Employee Benefits – Is the Company seeking recovery of Employee Recognition costs (i.e. $32,653) in the current rate case?

RESPONSE:

Yes, the Company is seeking recovery of Employee Recognition costs of $10,740 in the current rate case.

RESPONDENT:

Steve Bracamonte

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE

DOCKET NO. E-04204A-15-0142

August 17, 2015

RUCO 2.05

Short-Term Incentive Program ("PEP") – What was the amount PEP paid-out during the test year? In addition, is the Company seeking recovery of these costs in the current rate case?

RESPONSE:

Short-Term Incentive ("PEP") charged to UNS Electric during the 2014 test year was $674K and was included for recovery in the current rate case.

RESPONDENT:

Steve Sims

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 2, 2015

RUCO 3.1

Residential Bright Solar Customers – In brief narrative please reconcile the difference between the Company's Adjusted H-5 bill count number of 959 and the 944 which was used to calculate the Company's test year revenue and proposed revenue. In addition please provide a new H-5 bill count that reconciles to the 944 customer billing. Where did the 15 residential bright solar customers migrate to?

RESPONSE:

On a booked basis the Company had an average customer count of 79 during the test year, which calculates to 944 annual bills based on customer counts; however the test-year bill count was actually 959 bills. Typically, this would occur when a "cycle billed" customer receives more than one bill in a month. The Company did not annualize this rate schedule based on bills and maintained the customer count status for both present and proposed rates in the revenue proof.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 18, 2015

RUCO 4.01

Accumulated Deferred Income Tax ("ADIT") – On page 9, of Company Witness Jason Rademacher's testimony, he states that the Company has reduced its ADIT amount by its Net Operating Loss Carryforward ("NOLC"). Please provide the amount of the NOLC ADIT offset. In addition, please provide all other components that may be affected by the NOLC ADIT adjustment in this rate case (e.g. rate base and expenses), if not already provided.

RESPONSE:

Please refer to Rate Base – Accumulated Deferred Income Taxes.xlsm provided with response to UDR 1.001 for NOLC amounts. NOLC ADIT does not impact other components in this rate case. (The referenced file can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Pro Forma Adjustments.)

RESPONDENT:

Jason Rademacher

WITNESS:

Jason Rademacher

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 18, 2015

RUCO 4.02

Private Letter Ruling – Has the Company asked for a Private Letter Ruling from the Internal Revenue Service ("IRS"), in relation to its NOLC ADIT offset? If yes, please provide a copy of the letter sent to the IRS and the current status of this ruling.

RESPONSE:

No.

RESPONDENT:

Jason Rademacher

WITNESS:

Jason Rademacher

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
September 18, 2015

RUCO 4.03

Residential Bright Solar Customers – This is a follow-up question to RUCO Data Request 3.1 in which RUCO asked the following question:

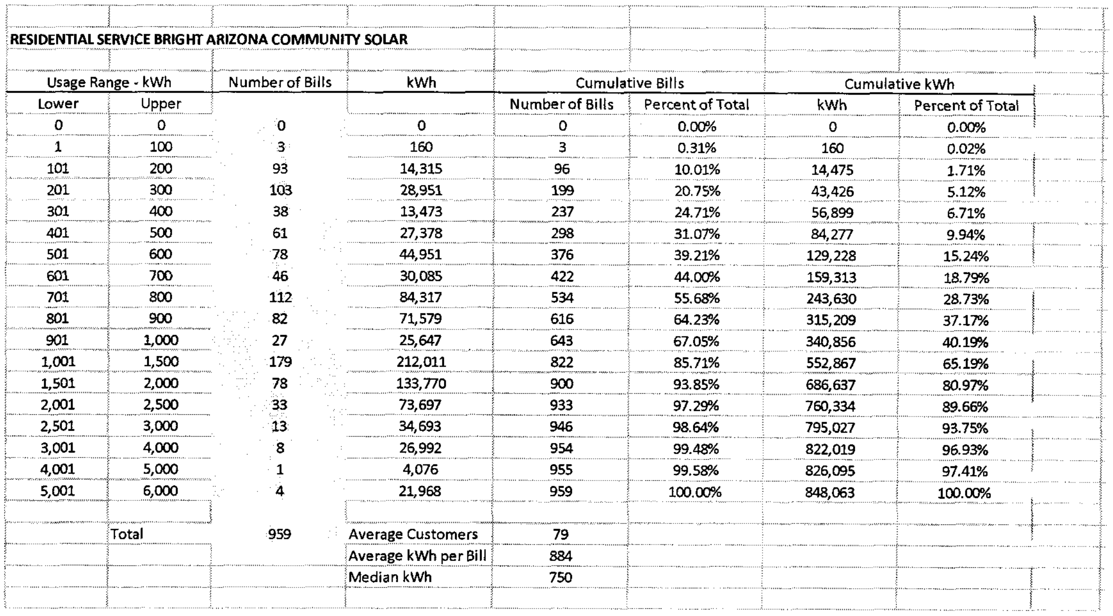
In a brief narrative please reconcile the difference between the Company's Adjusted H-5 bill count number of 959 and the 944 which was used to calculate the Company's test year revenue and proposed revenue. In addition please provide a new H-5 bill count that reconciles to the 944 customer billing. Where did the 15 residential bright solar customers migrate to?

The Company responded as follows:

On a booked basis the Company had an average customer count of 79 during the test year, which calculates to 944 annual bills based on customer counts; however the test-year bill count was actually 959 bills. Typically, this would occur when a "cycle billed" customer receives more than one bill in a month. The Company did not annualize this rate schedule based on bills and maintained the customer count status for both present and proposed rates in the revenue proof.

Thank you for your response. However the response was not fully responsive to RUCO's data request.

Based on the Company's excel "2015 UNSE Schedule H-5 ***Adjusted***" the following schedule has been reproduced below:



RESIDENTIAL SERVICE BRIGHT ARIZONA COMMUNITY SOLAR

Usage Range - kWh		Number of Bills	kWh	Cumulative Bills		Cumulative kWh	
Lower	Upper			Number of Bills	Percent of Total	kWh	Percent of Total
0	0	0	0	0	0.00%	0	0.00%
1	100	3	160	3	0.31%	160	0.02%
101	200	93	14,315	96	10.01%	14,475	1.71%
201	300	103	28,951	199	20.75%	43,426	5.12%
301	400	38	13,473	237	24.71%	56,899	6.71%
401	500	61	27,378	298	31.07%	84,277	9.94%
501	600	78	44,951	376	39.21%	129,228	15.24%
601	700	46	30,085	422	44.00%	159,313	18.79%
701	800	112	84,317	534	55.68%	243,630	28.73%
801	900	82	71,579	616	64.23%	315,209	37.17%
901	1,000	27	25,647	643	67.05%	340,856	40.19%
1,001	1,500	179	212,011	822	85.71%	552,867	65.19%
1,501	2,000	78	133,770	900	93.85%	686,637	80.97%
2,001	2,500	33	73,697	933	97.29%	760,334	89.66%
2,501	3,000	13	34,693	946	98.64%	795,027	93.75%
3,001	4,000	8	26,992	954	99.48%	822,019	96.93%
4,001	5,000	1	4,076	955	99.58%	826,095	97.41%
5,001	6,000	4	21,968	959	100.00%	848,063	100.00%
	Total	959	Average Customers	79			
			Average kWh per Bill	884			
			Median kWh	750			

This bill count coincidently is the same as the Company's excel "2015 UNSE Schedule H-5 ***Unadjusted***" 959 billings. This equates to an average customer billing of 79.9166 (i.e. 959/12) customers.

As part of the audit procedure RUCO ties the billing determents contained in the Company's H-5's to the Company's test year revenues and proposed revenues. Currently they do not tie.

As was previously requested, ***please provide a new H-5 bill count that reconciles to the 944 customer billings.*** Based on the above example, the Company should be able to provide a new H-5 schedule that has total billing determinants of 944, instead of 959 as is highlighted in the above schedule.

Further, as part of the response to RUCO data request 3.1 the Company states some customers were billed twice in one month. Please provide a listing of the month(s) customers were billed twice.

RESPONSE:

Please refer to **RUCO 4.03.xlsx** for a Schedule H-5 exhibit that reconciles to the 944 customer billings. The Excel file is <u>not</u> identified by Bates numbers. (2015 UNSE Schedule H-5 Adjusted.xlsx can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\\Workpapers – Schedules\Schedule G and H Support.)

During the test year period, the months of January, March, April, October, and November had instances where some Residential Service Bright Arizona Community Solar customers were billed twice during the month. Customers can be billed more or less than once during a given month for a variety of reasons, including bill cycle scheduling and starting or stopping service.

RESPONDENT:

Brenda Pries

WITNESS:

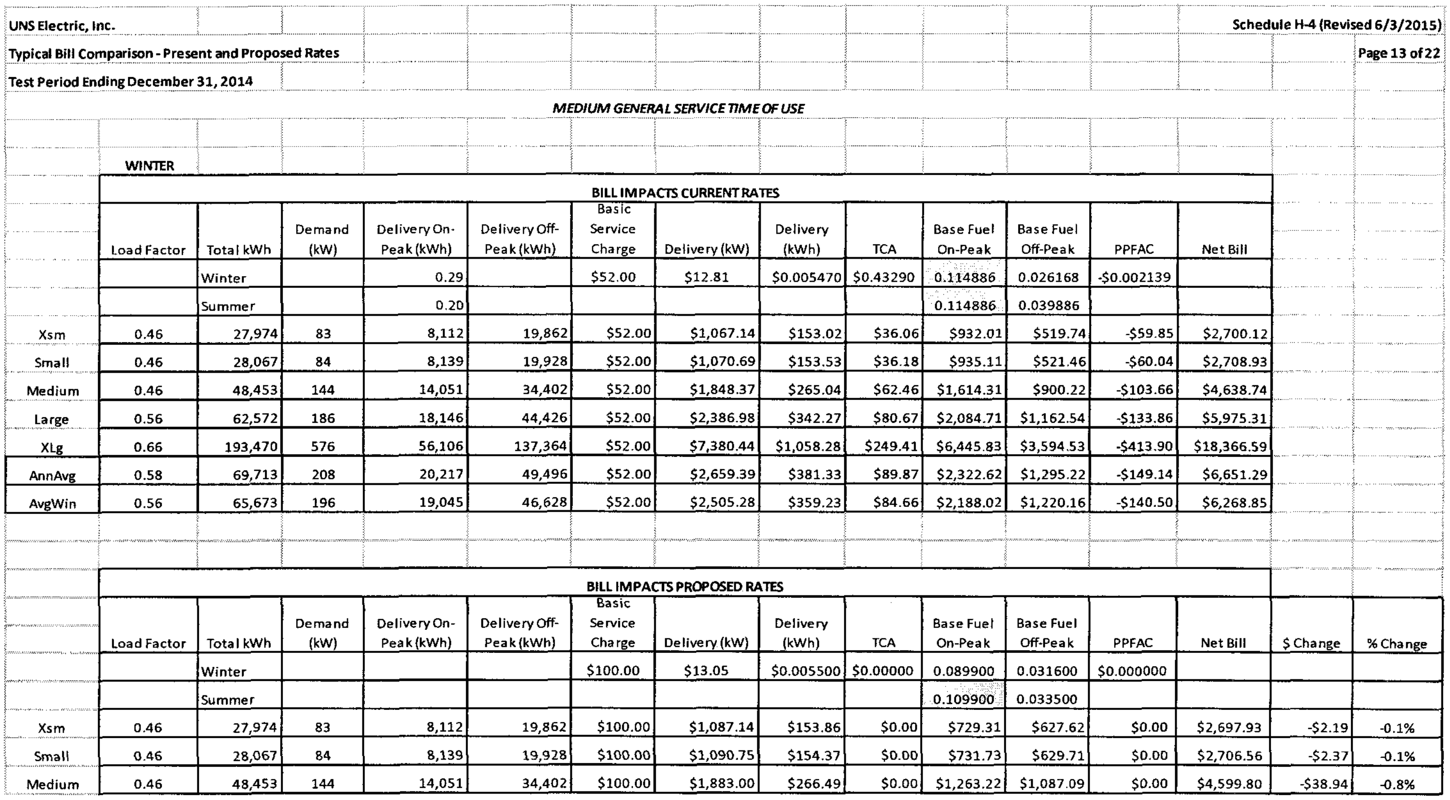
Craig Jones

RUCO 4.12

Large General Service TOU – Please explain why the Company used the following charges $0.109900 Summer on Peak, $0.033500 Summer off Peak, $0.089900 Winter on Peak, and $0.031600 (H-4) instead of tariff rates of $0.114886 Summer on Peak, $0.039866 Summer off Peak, $0.114886 Winter on Peak, and $0.026168 (H-3). In addition, the Company's TY Revenue Proof does not tie to the Company's Final Revenue Proof tab in the Company's "2015 UNSE Revenue Proof- Public Version" excel sheet test year revenue because of this discrepancy.

RESPONSE:

Below is a snap shot of Schedule H-4, which the Company filed for current and proposed rates. As shown below, the Company used its tariff rates for current bill impacts and the $0.109900 number referenced was used in the proposed bill impacts – see highlight below. These same rates are presented in Schedule H-3. (2015 UNSE Revenue Proof- Public Version.XLSX and 2015 Schedule H-4.xlsx can be accessed in UNS Electric's electronic data room under Data Requests\Uniform Data Requests\Attachments - 1st Set\UDR 1.001\Workpapers – Schedules\Schedule G and H Support.)



UNS Electric, Inc. Schedule H-4 (Revised 6/3/2015)
Typical Bill Comparison - Present and Proposed Rates Page 13 of 22
Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.05	$0.005500	$0.00000	0.089900	0.031600	$0.000000			
		Summer								0.109900	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,087.14	$153.86	$0.00	$729.31	$627.62	$0.00	$2,697.93	-$2.19	-0.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,090.75	$154.37	$0.00	$731.73	$629.71	$0.00	$2,706.56	-$2.37	-0.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$1,883.00	$266.49	$0.00	$1,263.22	$1,087.09	$0.00	$4,599.80	-$38.94	-0.8%

There are four key steps in the Company filed revenue proof: 1) test year revenues; 2) adjusted revenues; 3) adjusted revenues with the rebalance of fuel cost (proposed fuel rates); and 4) final revenues (proposed rates with rebalance of fuel cost – new fuel rates). The tab "TY Revenue Proof" demonstrates step one and two, whereas the tab "Final Revenue Proof" completes steps three and four. Since the average cost of fuel is reset in the case, the Company felt it was important to show this third interim step between adjusted revenues and proposed rates which shows current rates with new fuel rates. This is why all fuel rates for step three and four are the same. The comparison of adjusted test-year revenues to proposed are simply between step two and four.

Both test-year and adjusted revenues and the bill impacts use current rates for calculating current revenues and current bill impacts

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

RUCO 5.04

Rate Case Expense – What was amount of rate case expense agreed to by the parties in settlement Decision No. 74235 (dated December 31, 2013).

RESPONSE:

The rate case amount agreed to in the referenced decision was $300,000, which was less than the $1,086,226 actually incurred for preparing the rate case.

RESPONDENT:

Anne Liu

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 5.05

Lost Fixed Cost Recovery ("LFCR") – Is the Company still willing to honor an opt-out provision of the LFCR in this case?

RESPONSE:

The Company agreed in settlement in the last case to establish a fixed price option for Residential customers to choose, if they desired. It is the Company's understanding that this fixed price option is what RUCO is referring to in their question. With that assumption, the Company is not proposing that option in this proceeding. Company witness Craig Jones indicated this in his direct testimony on page 77 at lines 15-18 that no customers have expressed an interest in this option to date; therefore, the Company believes it's unnecessary to retain the option.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 5.06

Director and Officers' ("D&O") Liability Insurance – Please answer the following regarding D&O Liability Insurance:

a. What is the amount of D&O insurance that the Company is requesting to recover in this rate case?

b. Please provide a copy of the insurance policy.

c. Please provide the amounts of insurance that have been paid out if any for the last 5 years.

d. Is it the Company's intention to have ratepayers bear the full burden of this cost?

RESPONSE:

a. Please see UNS Electric's response to STF 16.05. The net amount of Officers & Directors Liability insurance premium included in the test year was $40,055.

b. The Company objects to the request to provide its D&O policy because it has negotiated favorable proprietary coverage it needs to keep confidential. Without waiver of objection, please see RUCO 5.06 10-19-15 UNS DO Insurance Summary 2014 to 2015.pdf, Bates Nos. UNSE\014691-014699, for a summary of the policy which provides the essential information regarding policy limits, deductible, coverages and policy exclusions in plain English rather than having to read 6 insurance policies.

c. No D&O claims have been paid by our insurers during the test period, nor have there been any claims paid for the previous five years. However, in 2015 a claim payment within the Company deductible was made to resolve the class action litigation objecting to the merger of UNS with Fortis. The UNS Electric expense portion of that settlement was $29,015 (9.39% of total based upon Massachusetts formula). In addition, the UNS Electric portion of an accrued expense reserve for notice of the settlement to shareholders is $4,695.

d. Yes, the Company is requesting a full recovery of D&O premium expense, because it is a standard business requirement in order to retain talented directors and officers, which is a benefit to the ratepayers. In addition, the majority of claims paid by D&O insurers for this type of coverage are on behalf of the insured entity, not individual directors and officers, which is a benefit to ratepayers, rather than being exposed to multi-million dollar claims.

RESPONDENT:

Karl Zimmel

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S FIFTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 5.07

Short-Term Incentive Program ("PEP") – This a follow-up to RUCO data request 2.05 in which RUCO asked the following:

What was the amount PEP paid-out during the test year? In addition, is the Company seeking recovery of these costs in the current rate case?

The Company responded:

Short-Term Incentive ("PEP") charged to UNS Electric during the 2014 test year was $674K and was included for recovery in the current rate case.

Based on the Company Income – Incentive Compensation Excel worksheet, please answer the following:

a. Please clarify that the Company is seeking recover of $673,550.92 as shown on the tab entitled query in adjusted test year expenses.

b. If no to a. The tab entitled PEP Summary Pivot shows a reduction of $(265,055) from $673,550.92 to $408,495, is this the adjusted test year expense amount that the Company is seeking in this rate case?

c. Please confirm that the $169,377 on the Rev-Exp tab is the amount of the pro-forma adjustment that relates to the PEP, which includes projected costs in 2016 and 2017, as shown on tab 3 year average adjustment.

d. Is the $169,377 in addition to the $673,550.92 or is it included in this amount? Please break-out the test year expense amount and pro-forma expense amount. In addition please identify the payroll amount associated with the PEP.

RESPONSE:

a. The Company is seeking recovery of $315,745 in normalized incentive compensation expenses as determined below:

Incentive Compensation - Query tab	$673,551
J903 PEP Transfer - PEP Summary Pivot tab	(265,055)
	408,496
Less:	
920 Capitalized - Adjusted PEP Summary tab	(26,961)
920 Capitalized - Adjusted PEP Summary tab	(72,645)
	$308,890
Add:	
Normalized 3 Yr. Avg. Adjustment	4,122
Normalized Tax	13,741
Normalized 3 Yr. Avg. incl. 2% Projected Cost	$326,753
ACC Jurisdictional Factor	.96631
Normalized Incentive Compensation Expenses	$315,745

b. Refer to part "a" above.

c. Yes.

d. No, the Company is requesting a total of $315,745, consisting of $169,377 ($175,281*.96631) plus $146,368 ($151,472*.96631). The PEP associated with total payroll is approximately 9%.

RESPONDENT:

David Lewis

WITNESS:

David Lewis

RUCO 6.1

Injuries and damages – Please answer the following regarding Injuries and damages?

a. The Company recorded injuries and damages of $1,071,000 in 2013, please break out the amounts between legal and medical expenses.

b. Please provide more detail of the incident, (i.e. time, day, persons involved).

c. Did the Company settle? If so why?

d. Why was the Company underinsured?

e. Is the Company currently underinsured?

f. Why did the Company not acquire supplemental insurance?

g. What is the deductible amount if any?

h. Please provide the 2011, and 2012 amounts for the following accounts

Account	Account Description	FERC	FERC Description
50250	Workers' Compensation	0925	Injuries & Damages
78040	Workers' Compensation	0925	Injuries & Damages
78100	Injuries & Damages	0925	Injuries & Damages

i. At what level does the Company's general liability insurance kick-in?

j. If self-insured, please provide in a brief narrative the coverage amounts, and threshold levels.

RESPONSE:

a. The $1,071,000 expense is for the claim reserve and/or liability claim payment for three claims.

b.
1. $1 Million claim reserve for a lawsuit in which the owner and tenant of a warehouse in Nogales allege a fire at their warehouse on 05-15-2013 was caused by an improperly installed dusk to dawn light that allegedly sparked causing the fire. On 07-24-2015 a jury returned a verdict in favor of UNS Electric with zero negligence and zero damages due. In July, 2015 the claim reserve was reversed.
2. $30,000 claim reserve for a pending lawsuit in which the plaintiff alleges UNS Electric was negligent for an auto accident on 05-15-2012 in Kingman, AZ resulting in injuries to the plaintiff.
3. $41,000 claim payment to the US Forest Service for firefighting expenses from a 2008 fire in Santa Cruz County allegedly caused by a downed power line.

c. The Company won the trial for the warehouse claim in Nogales. The auto accident in Kingman has not been settled and the litigation is still pending. The U.S. Forest Service claim was settled due to the documentation of a burned power line on the ground in the vicinity of the fire.

d. The Company was not underinsured for the three above mentioned claims. The expense for each claim is within the Company's self-insured retention, similar to having a deductible. Insurers charge significant additional premium above the actuarially expected loss amount for relatively low retention levels. Risk is better mitigated by utilizing insurance premium savings from self-insured retentions to procure higher insurance policy limits for protection from catastrophic losses. The Company regularly evaluates the most efficient level of self-insurance by taking into account the reduction in insurance premium for taking a higher retention of risk compared to the expected cost of self-insured claims from the higher retention. The Company self-insurance level is prudent based upon industry surveys and evaluation of its historical loss experience.

e. No, the Company is not currently underinsured. Continued evaluations of industry benchmarks and its own loss experience support the current amount of self-insurance and insurance policy limits above the self-insured retention.

f. The amount of losses incurred within the Company's self-insured retention is less than the premium it would pay for a lower retention.

g. The Company structures its Liability and Workers' Compensation policies with self-insured retentions rather than a deductible. While deductibles and self-insured retentions are a similar concept, insurance policies with self-insured retentions are less expensive than having deductibles. In addition, the Company insurer, which insures over 94% of investor owned utilities, only writes polices with self-insured retentions, not deductibles. The Company currently has a self-insured retention of $1 Million per occurrence for Auto Liability, $2 Million per occurrence for General Liability and $500,000 per occurrence for Workers' Compensation.

h. FERC 925 Injury and Damages for 2011 and 2012 are as follows:

Account	2011	2012
50250	$30,988.02	$55,586.04
78040	(23,305.42)	(32,916.52)
78100	-	10,000.00
Total	$7,682.60	$32,669.52

i. The Company transfers its risk to insurers via commercial insurance for losses above the self-insured retention levels stated in the response to question g.

RESPONDENT:

Rigo Ramirez (parts a, h) / Karl Zimmel (parts b, c, d, e, f, g, i, j)

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 6.2

Membership Dues – Please answer the following regarding membership dues?

a. Does the company have a more recent Edison Electric Institute Schedule of Expenses by NARUC Category for Core Dues Activities that list all nine categories (e.g. Legislative Advocacy) other than the December 31, 2005 version? If so, please provide a copy.

b. To clarify on the Company excel sheet entitled "Income – Membership Dues, tab Inv 124829," of the $35,000 invoice is it correct to say $3,500 was allocated to UNS and the remainder to TEP. If correct how was the allocation factor determined?

c. Please provide an itemized expense category listing of core activities that EEI Utility Air Regulation Groups participates in.

RESPONSE:

a. The Company does not retain the information requested through its normal course of business and/or does not have immediate access to, or authority from EEI, to provide the information requested. Please see UDR 1.54 for the EEI percentage devoted to legislative.

b. $3,500 is equal to 10% allocated to UNS Electric, Inc. (not UNS). Ten percent is representative of the amount of work generally performed by TEP's Corporate Environmental Services for UNS Electric, Inc. that relates to USWAG issues.

c. The core activities or areas of regulation that the Utility Air Regulatory Group participates in are follows:

   Ambient Standards

   Atmospheric Modeling

   Climate Change

   Control Technologies

   Hazardous Air Pollutants

   Measurement Techniques

   Nonattainment

   Plant Repair, Enforcement, and Permitting

   Regional Air Quality Effects

RESPONDENT:

Erik Bakken (parts a, c) / Rigo Ramirez (part b)

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE

DOCKET NO. E-04204A-15-0142

October 23, 2015

RUCO 6.3

Director and Officers Insurance – Please provide the amount of D&O prepaid insurance by month included in the test year?

RESPONSE:

As requested, listed below is the D&O prepaid insurance by month:

Month	Expense
Jan-14	$ 5,592.81
Feb-14	5,592.81
Mar-14	5,592.81
Apr-14	5,592.81
May-14	5,592.81
Jun-14	5,592.83
Jul-14	5,647.75
Aug-14	-
Sep-14	-
Oct-14	(656.68)
Nov-14	650.76
Dec-14	856.58
Total	$40,055.29

RESPONDENT:

Rigo Ramirez

WITNESS:

David Lewis

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S SIXTH SET OF DATA REQUESTS
REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
October 23, 2015

RUCO 6.4

Director and Officers Insurance - Has the Company included this amount in its calculation of working capital, or any other rate base line item? If so, please specify?

RESPONSE:

Yes, the Company has included $40,055.29 of Director and Officer Insurance in its calculation of working capital.

RESPONDENT:

Rigo Ramirez

WITNESS:

David Lewis